EXHIBIT 1

SIERRA CLUB

March 29, 2018

PDEQ
Air Program Manager, Rupesh Patel
33 N. Stone Avenue, Suite 700
Tucson, Arizona 85701
Submitted via e-mail at air.permits@pima.gov.

Re: Intent to Approve: Proposed Revision to the existing Air Quality Permit No. 1052 to Tucson Electric Power (TEP) Irvington/H.Wilson Sundt Generating Station (IGS)

Dear Mr. Patel,

Thank you for the opportunity to comment the proposed revision to the existing Air Quality Permit No. 1052 to Tucson Electric Power (TEP) Irvington/H.Wilson Sundt Generating Station (IGS). We submit these comments on behalf of Sierra Club and its 3 million members and supporters, including over 16,000 members in Arizona.

PDEQ is proposing to approve a permit for a major modification that will allow construction of ten Reciprocating Internal Combustion Engines (RICE), each with a capacity of 19 MW. IGS is a major source of emissions for particulate matter less than 10 microns in diameter (PM10), fine particulate matter (PM2.5), sulfur dioxide (SO2), nitrogen oxides (NOX), carbon monoxide (CO), carbon dioxide equivalent (CO2e), volatile organize compounds (VOCs), and hazardous air pollutants (HAPs). The new RICE units alone have the potential to emit 256.9 tons per year (tpy) of CO, 215.4 tpy of VOCs, 170.0 tpy of NOx, and 326.1 tpy of HAPS.[1]

As detailed below and in the attached report of Pless Environmental, Inc., PDEQ should deny the RICE Project because it does not comply with federal and state law.[2] Most significantly,

- TEP has avoided best available control technology (BACT) and air quality review of NOx by wrongfully taking credit for NOx emissions from shutdown of the 2 existing units and subtracting these emissions from the new units' expected emissions. The permit does not require both existing units to shut down unless 6 RICE units are constructed, so the facility

[1] Proposed TSD at PDF p. 156.
[2] ARS 49-481(A).

could continue to run an existing unit with the 5 RICE units, while still getting credit for shutting down both existing units. Also, TEP plans to run the existing units simultaneously with the new units for 180 days, but the emissions from the existing units can only be subtracted from the new units if they are shut down before the new units begin operations.

- Based on this erroneous netting analysis, neither TEP nor PDEQ performed a BACT analysis for NOx emissions. Pless' expert comments demonstrate that NOx emissions from the RICE units are significantly higher than what could be achieved with the best available control technology. Likewise, Pless' comments show that the proposed permit's emission limits for PM10 and PM2.5 does not reflect the maximum degree of reduction required under BACT.

- PDEQ underestimated the visibility impacts at Saguaro National Park because the modeling rate it employed does not reflect the maximum emissions – the potential to emit. The NOx rate PDEQ accepted for the modeling demonstration is not an enforceable condition in the permit so there is no assurance that the units will not emit NOx at a much higher rate. TEP should redo the modeling at the higher rate to show the true potential visibility impacts at Saguaro and/or the lower modeled emission rate should be enforceable in the permit.

- Many of the proposed permit conditions are not practically enforceable. Specifically, using stack tests once every two years to determine whether the RICE units are in compliance with the permit is woefully inadequate; the permit does not contain an unambiguous methodology for demonstrating compliance with the annual NOx emission cap, and there is no support for the applicant's "vendor-guaranteed" NOx rate that is used to demonstrate compliance.

- The agency did not adequately consider impacts to the surrounding community, which contains a 85% minority population. The agency's environmental justice report wrongly relies on the applicant's erroneous "netting" of pollutants that does not comply with the law and does not reflect the reality of the toxic air pollution that people in the community will breathe. The environmental justice analysis should consider the total amount of air pollution that the facility will emit and not subtract the emissions from the shutdown of the 2 existing gas units. A proper analysis of environmental justice impacts should include air quality modeling of the NOx impacts.

For all the reasons detailed in these comments and exhibits, PDEQ cannot issue the permit for this project.

I. Legal Background

A. The Clean Air Act and the National Ambient Air Quality Standards (NAAQS)

The Clean Air Act's central purpose is to protect public health and welfare.[3] Severe air pollution events in the 1940s to 60s sickened thousands, and even killed people, raising public awareness of the health hazards of air pollution.[4] Congress adopted the Clean Air Act Amendments of 1970 in response to growing public concern over those hazards.[5]

A key component for achieving the Act's public health goal is compliance with the NAAQS.[6] NAAQS are the maximum permissible levels of common pollutants in the ambient air. NAAQS are set at levels to protect public health with an "adequate margin of safety."

EPA has set NAAQS for six common air pollutants known as "criteria pollutants." They are particulate matter, ground-level ozone, carbon monoxide, sulfur oxides, nitrogen oxides, and lead.[7] PDEQ cannot issue a permit unless the proposal meets the requirements of the NAAQS.[8]

Exposure to particulate matter less than 10 microns in diameter (PM10) and fine particulate matter (PM2.5) leads to a variety of adverse health effects including premature death, heart attacks, strokes, birth defects, and asthma attacks. Fine particles are especially dangerous; they evade the body's filtering mechanisms, lodge deep inside our lungs and are able to cross over into our bloodstream.[9]

Sulfur dioxide (SO_2) emissions are both harmful to human health on their own, and contribute to the formation of fine particulate. Exposure to SO_2 for even very short time periods—such as five minutes—has significant health impacts including impaired lung function, aggravation of asthma, and respiratory and cardiovascular morbidity.[10] EPA has determined that SO_2 exposure

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[3] 42 U.S.C. § 7401(b)(1).
[4] *See* Arnold W. Reitze, Jr., The Legislative History of U.S. Air Pollution Control, 36 Hous. L. Rev. 679, 696, 698 (1999).
[5] *Id*. at 700-704; *see also Lloyd A. Fry Roofing Co. v. EPA*, 415 F. Supp. 799, 805 (W.D. Mo. 1976) ("[T]he Clean Air Act was enacted and amended for the purpose of protecting public health.").
[6] 42 U.S.C. §§ 7401, 7409.
[7] *See* 40 C.F.R. Part 50.
[8] PCC § 17.16.590(5); 17.12.020 (A).
[9] National Ambient Air Quality Standards for Particulate Matter, 78 Fed. Reg. 3,086 (Jan. 15, 2013); National Ambient Air Quality Standards for Particulate Matter, 71 Fed. Reg. 2,620, 2,626-7 (proposed Jan. 17, 2006) (EPA unable to find evidence supporting the selection of a threshold level of $PM_{2.5}$ under which the death and disease associated with $PM_{2.5}$ would not occur at the population level); Clean Air Fine Particle Implementation Rule, 72 Fed. Reg. 20,586, 20,586-87 (Apr. 25, 2007); 70 Fed. Reg. 65,983, 65,988 (Nov. 1, 2005) ("emissions reductions resulting in reduced concentrations below the level of the standards may continue to provide additional health benefits to the local population."); National Ambient Air Quality Standards for Particulate Matter, 62 Fed. Reg. 38,652, 38,656 (July 18, 1997) (EPA rulemakings detailing harmful impacts of particulate matter).
[10] *See* EPA, EPA/600/R-08/047F, Integrated Science Assessment for Sulfur Oxides—Health Criteria ch. 5 tbls. 5-1, 5-2 (2008); Primary National Ambient Air Quality Standard for Sulfur Dioxide, 75 Fed. Reg. 35,520, 35,525 (June 22, 2010); *see also* EPA, Our Nation's Air: Status and Trends Through 2008, 4

can also aggravate existing heart disease, leading to increased hospitalizations and premature deaths.[11] Short-term SO_2 exposure is especially dangerous for children with asthma.[12]

Nitrogen oxides ("NOx"), in combination with other pollutants like volatile organic compounds ("VOCs") and sunlight, create ground-level ozone – better known as smog – which contributes to asthma, bronchitis, and other respiratory and cardiovascular illnesses.[13]

NAAQS must be reviewed and updated every five years to reflect current scientific understanding on the health impacts of pollutants.[14] Over time, ambient air quality standards have become increasingly stringent as scientific understanding of health impacts has increased. Evidence has mounted linking short bursts of air pollution with severe health impacts, leading EPA to set updated standards for some pollutants on an hourly basis. The first sulfur dioxide standard was a 24-hour primary standard at 140 parts per billion (ppb) and an annual average standard at 30 ppb in 1971; in 2010, citing evidence linking short-term exposure to bronchoconstriction and increased asthma symptoms, as well as increased visits to emergency departments and hospital admissions for respiratory illnesses, EPA established a new 1-hour standard at a level of 75 ppb.[15]

Similarly, EPA established an additional one-hour primary standard for nitrogen oxides at 100 ppb in January 2010 after many studies established connections between short-term exposure to nitrogen oxides and adverse respiratory effects, increased visits to emergency departments, and hospital admissions for respiratory issues, especially asthma.[16] These recent 1-hour standards prove more than ever that ensuring compliance with emission limits at all times is critical to delivering on the Clean Air Act's promise of healthful air.

B. New Sources of Air Pollution Must Obtain Permits to Ensure Protection of the NAAQS.

The core goals of the Clean Air Act's preconstruction permitting program are to ensure that new sources of air pollution incorporate state-of-the-art pollution controls and do not contribute to air pollution in excess of air quality standards.[17] Congress targeted "major emitting facilities,"[18] such

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(2010) (noting that the health effects of sulfur dioxide exposure include aggravation of asthma and chest tightness), *available at* https://goo.gl/Wemzpd.

[11] Fact Sheet, Revisions to the Primary National Ambient Air Quality Standard, Monitoring Network, and Data Reporting Requirements for Sulfur Dioxide, *available at* https://www.epa.gov/sites/production/files/2016-05/documents/final_primary_naaqs_factsheet.pdf

[12] *See* 75 Fed. Reg. at 35,525.

[13] *See* Revision to the Rate of Progress Plan for the Beaumont/Port Arthur Ozone Nonattainment Area, 71 Fed. Reg. 8,962, 8,963 (Feb. 22, 2006).

[14] 42 U.S.C. § 7409.

[15] *See* EPA, Table of Historical Sulfur Dioxide National Ambient Air Quality Standards (NAAQS), *available at* https://www.epa.gov/so2-pollution/table-historical-sulfur-dioxide-national-ambient-air-quality-standards-naaqs

[16] *See* EPA, Nitrogen Oxides Effects, *available at* https://www.epa.gov/no2-pollution/basic-information-about-no2#Effects

[17] *See Nat'l Parks Conservation Ass'n v. Tenn. Valley Auth*., 480 F.3d 410, 412 (6th Cir. 2007); 42 U.S.C. §§ 7470-7492.

as the IGS plant, for stringent permitting because Congress' intent was to "identify facilities which, due to their size, are financially able to bear the substantial regulatory costs imposed by the [Prevention of Significant Deterioration] PSD provisions and which, as a group, are primarily responsible for emission of the deleterious pollutants that befoul our nation's air."[19] The preconstruction PSD process is critical for these massive sources of air pollution that operate for decades because there is little opportunity under the Clean Air Act to revisit the allowed emissions levels.

The preconstruction permit for a major source, referred to as a "PSD permit," has two central purposes, each critical to the Act's overall scheme: First, the permit sets the limits that will govern the plant's emissions of air pollutants to a rate consistent with the use of the best available methods, systems, and techniques of pollution control (in Clean Air Act jargon, this emission limit is called the "Best Available Control Technology" (BACT)). BACT is considered "[o]ne of the most critical elements of the PSD permitting process."[20] Second, the application must provide a comprehensive public assessment of the plant's impact on air quality, ensuring that air quality remains consistent with the Act's National Ambient Air Quality Standards as well as various site-specific ambient air quality standards, some of which are referred to as "increments."

The Act also contains special preconstruction permitting provisions to protect the public from hazardous air pollutants (HAPs). HAPs threaten human health and include substances that are "carcinogenic, mutagenic, teratogenic, neurotoxic, which cause reproductive dysfunction, or which are acutely or chronically toxic."[21] The purpose of the Act's HAP program is to require the stringent control of these dangerous pollutants because they could "cause, or contribute to, an increase in mortality or an increase in serious irreversible[] or incapacitating reversible[] illness."[22]

II. PDEQ Failed to Apply the Best Available Control Technology (BACT) to the RICE Units

BACT is "one of the most critical elements of the PSD permitting process."[23] BACT is defined as:

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[18] 42 U.S.C. § 7475.
[19] *Alabama Power Co. v. Costle*, 636 F.2d 323, 353 (D.C. Cir. 1979).
[20] *In re Knauf Fiber Glass*, 8 E.A.D. 121, 131 (E.A.B. 1999), 1999 WL 64235, at *8; hereinafter ("*Knauf I*")
[21] 42 U.S.C § 7412(b)(2). State courts often look to decisions from the Environmental Appeals Board (EAB) for guidance, affording the EPA's highest decision making authority significant deference. *See, e.g., United States v. S. Indiana Gas & Elec. Co*., 245 F. Supp. 2d 994, 1009-10 (S.D. Ind. 2003). The EAB is the final EPA decisionmaker on administrative appeals under all major federal environmental statutes. Arizona must interpret the Clean Air Act such that the state's program is no weaker than the federal program, as it has been interpreted by EPA. *See* 42 U.S.C. § 7416; *Alaska Dept. Envtl. Conservation v. EPA*, 540 U.S. 461 (2004) (upholding EPA's interpretations of BACT over state objections).
[22] *New Jersey v. EPA*, 517 F.3d 574, 577 (D.C. Cir. 2008).
[23] *Knauf I*, 8 E.A.D. at 131.

> an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.

40 C.F.R. § 52.21(b)(12); PCC § 17.04.340 (A)(37). To ensure that the limits in the permit ensure "maximum degree of reduction," the permit applicant is required to propose a permit limit that constitutes BACT and to supply sufficient information on the control option used to achieve that limit.[24] Specifically, the applicant must provide "[a] detailed description [of the] system of continuous emission[s] reduction [] planned for the source or modification, emission estimates," and any other information necessary to ensure a detailed analysis leading to a limit ensuring maximum achievable pollution reduction.[25]

To ensure that the BACT determination is "reasonably moored" to the Clean Air Act's statutory requirement that BACT represent the maximum achievable reduction through the use of various pollution control techniques, U.S. EPA established a top-down analysis process outlined in the 1990 New Source Review (NSR) Manual,[26] which PDEQ adopted in its review of the RICE unit. Each step of the BACT analysis, and especially a decision to reject an effective pollution reduction option in favor of a less effective option when establishing a BACT limit "must be adequately explained and justified."[27]

A BACT analysis begins with the identification of all available control technology options for each regulated pollutant.[28] This step must include "inherently lower-polluting processes," "technologies employed outside of the United States," "controls applied to similar source categories and gas streams and innovative control technologies."[29] BACT's forward-looking emphasis is the "most important" mechanism promoting the Clean Air Act's "philosophy of encouragement of technology development." The BACT standard is intended to require the use

[24] *In re* Genesee Power Station Ltd., 4 E.A.D. 832 (E.A.B. 1993) WL 484880, at *3.
[25] 40 C.F.R. § 52.21(n); NSR Manual at B.24. EPA issued detailed guidance for permitting authorities on how to best perform a BACT analysis that comports with the statute's mandate in its NSR Manual. EPA's adjudicatory arm for Clean Air Act permitting, the Environmental Appeals Board (EAB), explained the import of the NSR Manual in evaluating BACT determinations *in In re N. Mich. Univ*., slip op. at 54-55, PSD Appeal 08-02, 2009 WL 443976, at *8 (EAB Feb. 18, 2009). PDEQ adopted the NSR manual's BACT approach here. Proposed TSD Attach. C at PDF 191.
[26] *Alaska Dept. of Envt'l Conservation v. EPA*, 540 U.S. 461, 485 (2004).
[27] *Knauf I*, 8 E.A.D. at 131; NSR Manual at B.26-B.29; *In re General Motors, Inc*., 10 E.A.D. 360, 379 (EAB 2002*); In re Steel Dynamics*, Inc., 9 E.A.D. 165, 206-07 (EAB 20022000);
In re Masonite Corp., 5 E.A.D. 551, 546-69 (EAB 1994).
[28] NSR Workshop Manual B.5-9.
[29] *Id.*

of “the latest technological developments [in pollution control] as a requirement in granting the permit,” so as to “lead to rapid adoption of improvements in technology as new sources are built,” rather than “the stagnation that occurs when everyone works against a single national standard for new sources.”

Nex,t technical infeasible options are eliminated only if “clearly documented…based on physical, chemical and engineering principles.”[30] The control technologies are next ranked by “effectiveness” based on efficiency, emission rate, and emission reductions.[31]

In Step 4, starting with the most stringent technology, the economic, environmental, and energy impacts, “both beneficial and adverse,” are evaluated and quantified if possible.[32] Only if this analysis documents that the first ranked technology is inappropriate, that technology is eliminated and the next most effective alternative evaluated. Based on this process, the most effective, achievable technology is proposed as BACT.[33] As the Supreme Court has recognized, the definition of BACT contains the “strong, normative terms ‘maximum’ and ‘achievable.’” PDEQ must articulate a sound basis with supporting documentation to select anything other than the most stringent emissions limit achievable.[34]

As discussed in the attached technical comments by Pless Environmental, Inc., the proposed permit fails to establish BACT for NOx, PM10, and PM2.5.[35] Based on an erroneous netting analysis, neither the Applicant nor PDEQ performed a BACT analysis for NOx emissions. Pless’ comments demonstrate that NOx emissions from the RICE units are significantly higher than what could be achieved with the best available control technology. Likewise, Pless’ comments show that the proposed permit’s emission limit for PM10 and PM2.5 does not reflect the maximum degree of reduction required under BACT. Under PCC § 17.16.590, PDEQ cannot issue the permit without conducting a BACT analysis for NOx and redoing its BACT analysis for PM10 and PM2.5.

III. PDEQ’s Air Quality Impact Modeling Does Not Demonstrate That the RICE Project Will Not Cause Air Quality Deterioration and Underestimates Visibility Impacts

One of the Clean Air Act’s most fundamental requirements is that a permit applicant must show that emissions from a new facility would not contribute to significant air quality deterioration.[36] A permit applicant must show that emissions from a new facility would not cause or contribute to a violation of ambient air quality standards or the increment.[37] “[W]orst case emissions should

[30] *Id.*
[31] *Id.*
[32] *Id.*
[33] *Id.*
[34] *Id*. at 484-87, *see also In re Indeck-Elwood*, 2006 WL 3073109 at *6.
[35] Pless Comments at 17-19.
[36] 42 U.S.C. § 7475(a)(3); 40 C.F.R. § 52.21(c) & (d); PCC §§ 17.16.590;17.16.630.
[37] 42 U.S.C. §§ 7473, 7475(a)(3); 40 C.F.R. § 52.21(c) & (d); PCC §§ 17.16.590 (5).

be employed in the modeling analyses conducted to demonstrate a facility's compliance with the NAAQS and PSD increments."[38] As the NSR Manual explains:

> For both NAAQS and PSD increment compliance demonstrations, the emissions rate for the proposed new source or modification must reflect the maximum allowable operating conditions as expressed by the federally enforceable emissions limit, operating level, and operating factor for each applicable pollutant and averaging time.[39]

As demonstrated in Pless' comments, the modeling in the permitting record does not support issuance of the proposed permit for the RICE units.[40] Most significantly, PDEQ underestimated the visibility impacts at Saguaro National Park because the modeling rate used does not reflect the maximum allowable operating conditions, which is the potential to emit. Moreover, the NOx rate used for the modeling is not an enforceable condition in the permit so there is no assurance that the units will not emit NOx at a much higher rate. TEP must redo the modeling at the legally mandated higher rate to show the potential visibility impacts at Saguaro and/or the lower modeled emission rate must be included as an enforceable limit in the permit.

Additionally, PDEQ's modeling for CO, PM10, and PM2.5 is not supported because the modeling was based on average emission rates instead of worst case emissions, PDEQ failed to model secondary PM2.5 emissions, and PDEQ did not model NO2 impacts. PDEQ must revise and perform these analyses in order to support issuance of the permit.[41]

IV. The Proposed Permit Conditions Are Not Enforceable

To be practically enforceable, a permit must contain adequate monitoring procedures to assure compliance with emissions limits.[42] Practical enforceability means the source must be able to show continuous compliance with each limitation requirement,[43] and the permit must include adequate testing, monitoring, and recordkeeping requirements.[44]

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[38] *See in In re N. Mich. Univ.*, 14 E.A.D. 283, 319 (E.A.B. 2009), 2009 WL 443976 at *30 (remanding permit for using modeling that could result in underestimated emissions); *Ober v. U.S. EPA*, 84 F.3d 304, 309 (9th Cir. 1996) (holding Clean Air Act requires attainment of all NAAQS, including a 24 hour standard for particulate matter).

[39] NSR Manual, at C.45 (emphasis in original).

[40] Pless Comments at 26-32.

[41] PCC § 17.16.590.

[42] *In re Peabody*, 12 E.A.D. 22 (E.A.B. 2005) WL 428833, at *12; NSR Manual, at A.5, B.56; *United States v. Louisiana-Pac. Corp.*, 682 F. Supp. 1122, 1132-33 (D. Colo. 1987). EPA objected to the Title V permit for the Big Stone coal plant for this very reason. The permit "fail[ed] to indicate how the permittee must demonstrate that it is maintaining emissions at a level below the major source thresholds…" Letter from U.S. EPA to Steven M. Pirner, P.E. Sec'y, S.D. Dep't of Env't and Natural Res. (Jan. 22, 2009), at 11.

[43] Terrell E. Hunt & John S. Seitz, U.S. EPA, Guidance on Limiting Potential to Emit in New Source Permitting (June 13, 1989), at 3-5, hereinafter ("Guidance to Limiting PTE in NSR"); NSR Manual, at A.5.

[44] NSR Manual, at A.5.

In re Peabody W. Coal Co.,[45] demonstrates proper application of enforceability requirements. The Environmental Appeals Board (EAB) upheld EPA's refusal to accept the mine's proposed limits because Peabody "ha[d] not sufficiently demonstrated that it met the central criteria for establishing such limits – technical accuracy and a reliable method of determining compliance."[46] For example, Peabody had not "proposed monitoring sufficient to establish a practically enforceable PTE limit."[47]

Blanket limits alone, such as the proposed permit's ton per year NOx limit, are not practically enforceable because they are "virtually impossible to verify or enforce."[48] "Compliance with any limitation must be able to be established at any given time…restrictions [must be] written in such a manner that an inspector could verify instantly whether the source is or was complying with the permit condition."[49] To be enforceable, permits must "specify a reasonable averaging time consistent with established referenced methods…"[50] Additionally, emissions limits should be expressed in two ways, "with one value serving as an emissions cap (e.g., lb/hr) and the other ensuring continuous compliance at any operating capacity (e.g. lbs/MMBTU)."[51]

Pless' expert comments detail at length the enforceability issues with the proposed permit.[52] Specifically, using stack tests once every two years to determine whether the RICE units are in compliance with the permit is woefully inadequate. The permit does not contain an unambiguous methodology for demonstrating compliance with the annual NOx emission cap, and there is no support for the applicant's "vendor-guaranteed" NOx rate that is used to demonstrate compliance. Also, some of the permit conditions have *no* testing requirements whatsoever, and the permit does not contain a condition to ensure that fuel sulfur content in natural gas is below the 7,500 grains per million cubic feet assumed for the TEP's emission calculations.

V. Conclusion

Thank you for your consideration of our comments and for all you do to protect Arizona's airsheds and environment and the health of our communities.

[45] 12 E.A.D. 22 (E.A.B 2005) WL 428833.
[46] *Id*. at *12.
[47] *Id*.
[48] *Louisiana-Pac. Corp.*, 682 F. Supp. at 1133; Guidance to Limiting PTE in NSR at 3-5; Memo from John S. Seitz, Office of Air Quality Planning and Standards to Air Management Division Directors et al. (Apr. 8, 1987); NSR Manual, at c.4.
[49] NSR Manual, at c.3.
[50] *Id.* at B.56.
[51] *Id.* at H.5; see also *Id.* at I.2.
[52] Pless Comments at 20 -26.

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March 29, 2018

Via Email

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Re: Review of Pima County Department of Environmental Quality's Proposed Prevention of Significant Deterioration Air Quality Permit No. 1052 for Tucson Electric Power's Irvington Generating Station

Dear Ms. Issod,

Per your request I reviewed the Proposed Prevention of Significant Deterioration ("PSD") air quality permit ("*Proposed Permit*") and associated Draft Technical Support Document ("*Proposed TSD*") prepared by Pima County Department of Environmental Quality ("PDEQ") for authorization and significant revision to the existing Class I, Title V air quality permit No. 1052 for the Irvington Generating Station ("IGS" or "Facility"), also known as the H. Wilson Sundt Generating Station, in the City of Tucson, Arizona, which is owned and operated by Tucson Electric Power ("TEP" or "Applicant").[1][2][3]

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[1] The Curriculum Vitae of Petra Pless is attached as Exhibit 1.

[2] PDEQ, Draft Prevention of Significant Deterioration Air Quality Permit, Issued to Tucson Electric Power Irvington Generating Station, 3950 East Irvington Road, Tucson, AZ 85714, February 2018; available at: http://webcms.pima.gov/UserFiles/Servers/Server_6/File/Government/Environmental%20Quality/Air/TEP%20PSD%20Webpage/1052-Proposed-Permit.pdf, accessed March 18, 2018.

[3] PDEQ, Draft Technical Support Document (TSD), TEP Irvington Generating Station, Air Quality Permit # 1052, February 2018, 15 pages; available at: http://webcms.pima.gov/UserFiles/Servers/Server_6/File/Government/Environmental%20Quality/Air/TEP%20PSD%20Webpage/1052-Proposed-TSD.PDF, accessed March 18, 2018.

Supporting documents for my review include TEP's application for the Facility modification dated July 2017[4] ("*7/17 Application*"), TEP's revised application dated December 2017[5] ("*12/17 Revised Application*"), and other relevant documents found in the docket for the *Proposed Permit*[6] and elsewhere.

As discussed in my comments below, the *Proposed TSD* is substantially flawed and the *Proposed Permit* is not consistent with the requirements of the federal Clean Air Act ("CAA" or "the Act").

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[4] Tucson Electric Power, Application for a Prevention of Significant Deterioration (PSD) Authorization and Significant Revision to Class I Air Quality Permit for Irvington Generating Station, submitted to Pima County Dept. of Environmental Quality, prepared by RTP Environmental Associates, Inc., July 2017; available at: http://webcms.pima.gov/UserFiles/Servers/Server_6/File/Government/Environmental%20Quality/Air/TEP%20PSD%20Webpage/17-08-01-PSD-Air-Permit-Application.pdf , accessed February 20, 2018.

[5] Tucson Electric Power, Application for a Prevention of Significant Deterioration (PSD) Authorization and Significant Revision to Class I Air Quality Permit for Irvington Generating Station, submitted to Pima County Dept. of Environmental Quality, prepared by RTP Environmental Associates, Inc., July 2017 (Revised December 2017); available at: http://webcms.pima.gov/UserFiles/Servers/Server_6/File/Government/Environmental%20Quality/Air/TEP%20PSD%20Webpage/17-12-19-Sundt-RICE-Project-Revised-Application.pdf, accessed March 18, 2018.

[6] PDEQ, TEP Application for PSD Authorization; available at: http://webcms.pima.gov/cms/One.aspx?portalId=169&pageId=363558.

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I. Facility and Project Description

The existing Facility is an electric utility power generating station with a combined, nominal, net generating capacity of 470 megawatts ("MW") that generates electricity by fossil fuel (natural gas, liquid fuel) and landfill gas combustion. The Facility consists primarily of electric utility steam generating units ("EGUs"), stationary combustion turbines with starter engines, cooling towers, emergency generators, and other processes and equipment associated with power generation. There are four fossil fuel-fired EGUs (each consisting of a boiler, steam turbine, and generator), designated as Units I1 through I4, with a net generating capability of 81 MW, 81 MW, 104 MW, and 156 MW, respectively, and two simple-cycle peaking internal combustion turbines with black-start capability, designated as IGT1 and IGT2, with a combined net generating capability of 48 MW.[7]

TEP is proposing to install up to ten natural-gas fired reciprocating internal combustion engines ("RICE") at the IGS Facility to provide flexible, fast-responding capacity and assist in mitigating power fluctuations associated with renewable resources.[8] Specifically, the proposed Facility expansion includes construction of up to ten 18-cylinder, four-stroke, lean-burn spark-ignited RICE units manufactured by Wartsila, which would be fueled exclusively by pipeline natural gas. Each RICE unit would have a mechanical output capacity of 26,820 horsepower ("hp") and would be connected to an air-cooled electric generator with a nominal net generating capacity of 19 MW. Each RICE unit would be equipped with an oxidation catalyst to control emissions of VOC, CO, and HAPs and a selective catalytic reduction ("SCR") system to control emissions of NOx.[9] Ancillary equipment includes natural gas piping and electrical circuit breakers. Collectively, the *Proposed TSD* and my comments refer to these modifications as "the RICE project."

In conjunction with the RICE project, TEP proposes to permanently cease operation of the two 1950s-era steam-turbine cycle electric generating units Unit I1 and Unit I2 (81 MW each). The RICE project in conjunction with the shutdown of Units I1 and I2 would increase the combined nominal net generating capacity of the IGS Facility from 470 MW by 28 MW to 498 MW.[10]

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[7] *Proposed Permit*, p. 4, *Proposed TSD*, pp. 1-2, and Appx. C, Att. B, p. 1, and *12/17 Revised Application*, p. 1-1.

[8] *Proposed TSD*, p. 1, and *12/17 Revised Application*, pp. 2-1, 2-5, 3-5, 5-3, and 5-4.

[9] *12/17 Revised Application*, p. 2-6.

[10] *12/17 Revised Application*, p. 1-1.

II. Current Facility Permit and Proposed Permit Revision

PDEQ issued the most recent version of the air quality permit for the existing Facility pursuant to the New Source Review ("NSR") requirements of the federal Clean Air Act ("CAA" or "the Act"), No. 1052, on January 6, 2017.[11] According to the technical support document for this permit ("*1/17 TSD*"),[12] the existing Facility-wide potential to emit exceeds the applicable major source thresholds for emissions of criteria pollutants[13] of 100 tons per year ("tons/year" or "tpy") for nitrogen oxides ("NOx"), carbon monoxide ("CO"), volatile organic compounds ("VOC"), sulfur dioxide ("SO_2"), and particulate matter equal to or smaller than 10 micrometers ("PM10") and equal to or smaller than 2.5 micrometers ("PM2.5").[14] The Facility operates within an area that is currently classified as attainment for all criteria pollutants[15] and is, thus, an existing Class I major stationary source pursuant to the prevention of significant deterioration ("PSD") review requirements of the Act. In addition, the existing Facility has a facility-wide potential to emit in excess of the major source thresholds of 25 tons/year for total hazardous air pollutants ("HAPs") and 10 tons per year of a single HAP[16] and, thus, is an existing major stationary source pursuant to 42 USC §7412(a)(1). Further, the *1/17 TSD* identified the existing Facility as a major source of carbon dioxide-equivalent ("CO_2e") greenhouse gas ("GHG") emissions.[17]

The *Proposed Permit* constitutes a significant revision to the existing Class I, Title V air quality permit which would authorize the construction of the RICE project as

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[11] *Proposed TSD*, pp. 2 and 3.

[12] *See Proposed TSD*, Appx. A.

[13] Criteria air pollutants, or simply criteria pollutants, are six common air pollutants – particulate matter, photochemical oxidants (including ozone), carbon monoxide, sulfur oxides, nitrogen oxides, and lead – for which the U.S. Environmental Protection Agency establishes National Ambient Air Quality Standards ("NAAQS") based on characterizations of the latest scientific information regarding their effects on health or welfare and the environment.

[14] 40 CFR §52.21(b)(1) defines the major source threshold for fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input as 100 tons/year or more for any regulated NSR pollutant.

[15] *Proposed TSD*, p. 3

[16] *1/17 TSD*, p. 7. ("For Title V air permitting purposes, the threshold to trigger a major source status is 100 tpy of any criteria air pollutant, 10 tpy of any single hazardous air pollutant (HAP), 25 tpy of any HAPs combination, 100,000 tpy CO_2 equivalent emissions of greenhouse gases. As shown in the summary table, IGS is a major Title V source for the following air pollutants: PM10, PM2.5, SO_2, NOx, CO, CO_2e, VOC, and HAPs.")

[17] *Id.*

a major modification of the existing major stationary source.[18] Specifically, the *Proposed TSD* finds that emissions increases from the RICE project exceed the respective PSD significance levels for six pollutants: NOx, VOC, CO, PM10, PM2.5, and GHGs.[19] However, TEP is voluntarily accepting a permit cap for NOx emissions of 170.0 tons/year for all ten RICE units combined[20] to ensure that the net emissions increase for NOx associated with the RICE project, when accounting for the emission reductions resulting from the shutdown of Units I1 and I2, is not significant[21] and, thus, does not trigger PSD review. Accordingly, the *Proposed TSD* finds that, the net emissions increase of NOx from the RICE project is not significant and, thus, PSD review is not required with respect to NOx. For the other five pollutants (VOC, CO, PM10, PM2.5, and GHGs), TEP claims no creditable decreases in actual emissions, and, consequently, the *Proposed TSD* finds that net emissions increases of these pollutants are equal to the emissions increases associated with the RICE project. Therefore, PDEQ finds that the RICE project constitutes a major modification of the current Class I, Title V air quality permit for the Facility triggering PSD air impact analyses for VOC, CO, PM10, and PM2.5 and best available control technology ("BACT") requirements for VOC, CO, PM10, PM2.5, and GHGs.[22]

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[18] *Proposed TSD*, p. 3.

[19] *Proposed TSD*, p. 10.

[20] Conrad Spencer, TEP, Letter to to Rupesh Patel, PDEQ, February 23, 2018; available at: http://webcms.pima.gov/UserFiles/Servers/Server_6/File/Government/Environmental%20Quality/Air/TEP%20PSD%20Webpage/18-02-23-TEP-Voluntary-Proposed-NOx-Limit.pdf, accessed March 28, 2018. ("First, regarding the voluntarily proposed NOx emission cap: The limit requested in Section 4.5.3 of the permit application was 179.0 tons per year. Based on that proposed limit, the net NOx emissions increase as documented in Table 4-1 of the permit application, was 39.4 tons per year. Concerns were expressed by the governmental agencies regarding the small compliance margin relative to the PSD significant level of 40 tons per year. In order to alleviate these concerns, TEP informally requested that PDEQ reduce the NOx emission cap to a more restrictive level of 170.0 tons per year. This results in a net NOx emissions increase of 30.4 tons per year, which provides a 24 percent compliance margin relative to the PSD significant level of 40 tons per year. The more stringent NOx emission cap of 170.0 tons per year is already reflected in Condition II.A.1.a of the draft permit currently available for public notice and comment. With this letter, TEP formally requests the more stringent NOx emission cap of 170.0 tons per year.")

[21] 12/17 Revised Application, p. 4-6. ("As provided by PCC §§ 17.12.190 and 17.12.195, TEP is voluntarily proposing three separate, substantive requirements that will ensure the net emissions increase for NOx as a result of the RICE project is not significant: A requirement to shut down permanently either Unit 1 or Unit 2 at the IGS within 180 days following initial startup of the first RICE; a requirement to have shut down permanently both Units 1 and 2 at the IGS within 180 days following initial startup of the sixth RICE; and a NOx emission cap of 179.0 tpy for the ten RICE to be installed at the IGS.")

[22] *Proposed TSD*, pp. 10 and 11.

III. The Proposed TSD Is Deficient as a Support Document for the Proposed Permit

The *Proposed TSD* fails to properly establish the potential to emit for the RICE units and fails to provide all information it relied upon to calculate potential to emit.

A. The Proposed TSD Fails to Properly Establish Potential to Emit for the RICE Units

Typically, the technical support document for a permit contains a discussion of how emission limits in the permit were determined and, in the case of a modification of an existing stationary source, a demonstration of the net emissions increase for each pollutant. The *Proposed TSD* provide no such explanations and instead simply presents a table allegedly containing the "potential to emit" for all new and existing sources at the Facility in a table entitled "*IGS Facility Wide Potential to Emit (tons/year) Summary*." With respect to emission limits contained in the *Proposed Permit*, the *Proposed TSD* simply states that "[t]he detailed RICE Project emission calculations and calculation methodology are included in Attachment A of Appendix C."[23] In order to track down the origin of the respective emission limits and verify that the RICE project would not constitute a major modification for NOx emissions, as claimed by the *Proposed TSD*, the reviewer must wade through the appendices to the *Proposed TSD* and other documents contained in the docket such as the *12/17 Revised Application* and a letter from the Applicant specifying the revised NOx emission cap.[24] Because the *Proposed TSD* will be a standalone document for further permit revisions, all information relied upon to determine the potential to emit for the RICE units and the proposed shutdown of Units I1 and I2 must be included as part of the document.

Further, the *Proposed TSD* explains with the "potential to emit" presented in the *IGS Facility Wide Potential to Emit (tons/year) Summary* table:

> The following table summarizes IGS annual potential to emit of air pollutants by each emission unit and by facility-wide total. The emission estimate is to establish "major source" status of IGS pursuant to CAA Sec 501(2). Other use with the estimate may include comparing source potential-to-emit with emissions inventory and test data, or with emission rates allowable by relevant standards. This emission estimate is not meant to establish any baseline emission

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[23] *Proposed TSD*, p. 6.

[24] Letter from Conrad Spencer, TEP, to Rupesh Patel, PDEQ, February 23, 2018. ("With this letter, TEP formally requests the more stringent NOx emission cap of 170.0 tons per year.")

> levels. These emission figures are not meant to be emission limitations of any form.[25]

The *Proposed TSD* does not explain why the "emission figures" do not reflect the true potential to emit for the Facility and its equipment based on the permit conditions.

The term "potential to emit" is a defined term for purposes of PSD review:

> Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable.

PCC §17.04.340(A)(175); 40 CFR 52.21(b)(4). The *Proposed TSD* should be revised to reflect the potential to emit for all emissions units consistent with this definition.

Further frustrating review, the *Proposed TSD* presents two different definitions for the term "potential to emit "("PTE") for the RICE units. Specifically, the emission calculations provided in Attachment A to Appendix C of the *Proposed TSD*, which purportedly support the potential to emit for these units presented in the summary table *IGS Facility Wide Potential to Emit (tons/year) Summary,*"[26] refer to "Proposed Potential to Emit" and "Estimated Potential to Emit." The former is consistent with the potential to emit presented in the summary table and the latter is based on vendor-supplied startup and controlled emission rates, which are lower and were used for modeling purposes. (Modeling must be based on the maximum emission rates incorporated into enforceable permit condition; *see* Comment VII.B.)

In sum, the *Proposed TSD* frustrates public review and should be revised to address the issues outlined above. In order to facilitate review, the *Proposed TSD* should include tables for BACT emission limits and net emissions increases for all pollutants.

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[25] *Proposed TSD*, p. 6.

[26] *Proposed TSD*, p. 6. ("The emissions from the new RICE units are calculated based on 8,760 hours of operation per year for each of the ten RICE. The summarized RICE potential to emit is included in Table 1 (below). Assumptions are presented in the Table 1 footnotes. The detailed RICE Project emission calculations and calculation methodology are included in Attachment A of Appendix C.")

B. All Documents Relied Upon for Preparation of the Proposed TSD and Proposed Permit Must Be Provided

The emission calculations provided in Appendix C, Attachment A, to the *Proposed TSD*, which purport to support the potential to emit provided in the *IGS Facility Wide Potential to Emit (tons/year) Summary* table, refer a number of times to vendor information provided by TEP in a letter entitled "*Vendor Emissions Performance Specifications, H. Wilson Sundt Generating Station Rice Project*," dated September 21, 2017.[27] This document is neither attached to the *Proposed TSD* nor can it be found in the record.

Without the document in the permitting record, the assumed emission rates from this letter, specifically the cold startup emission factors and 60-minute average flue gas emission rates after control system startup for 25% to 100% engine loads, are not supported. Consequently, the emission calculations for potential to emit for the RICE units are not supported. This document must be provided with the *Proposed TSD*.

IV. The Facility May Not Net Out of PSD Review for NOx Emissions from the New RICE Units

A facility may determine for a particular project that there will not be a significant emissions increase—and thereby avoid air impact analyses and pollution controls/emission rates consistent with BACT—only after adding and subtracting all "contemporaneous" emissions increases and decreases from the entire facility and determining there will be no significant "net" emission increases. This process is called "netting." TEP desires to net out of the PSD review for NOx emissions from the new RICE units by accepting an emission cap of 170.0 tons/year and accounting or the emission decreases associated with the shutdown of Units I1 and I2.

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[27] *See Proposed TSD*, Appx. C, Att. A, footnote 2 to Table A-2 ("Proposed PTE Calculations for PM10, PM2.5, CO, and VOC assume 5 cold startup events per RICE per day. Per vendor information provided by TEP letter *Vendor Emissions Performance Specifications, H. Wilson Sundt Generating Station Rice Project*, date September 21, 2017, a cold start "...is when the temperature of the catalyst material inside the reactor is close to ambient temperature..." and that cold starts "... are expected after over haul periods or when the engine has not been operated during the last 2-3 days."), footnote 8 to Table A-2 ("Vendor supplied cold startup emission factors provided in TEP letter *Vendor Emissions Performance Specifications, H. Wilson Sundt Generating Station Rice Project*. September 21, 2017."), and footnote 9 to Table A-2 ("Vendor supplied 60 minute average flue gas emission rates after control system startup for 25% to 100% engine loads provided in TEP letter *Vendor Emissions Performance Specifications, H. Wilson Sundt Generating Station Rice Project*, September 21, 2017."),

Pursuant to PCC §17.04.340(A)(127) and 40 CFR §52.21(a)(2)(iv) and (b)(2), a project is a "major modification" if it will cause a net emissions increase that is significant for any pollutant regulated by the PSD program. "Significant" is defined for each NSR pollutant at PCC §17.04.340(A)(212) and 40 CFR §§52.21(b)(23). For NOx, the significant emission rate is 40 tons/year.

As discussed below, the netting analysis for NOx emissions from the RICE project is not supported and the net emissions increase of NOx is significant, thus triggering PSD review including an air quality impact analysis and BACT review for this pollutant.

A. The Emissions Decreases from Proposed Shutdown of Units I1 and I2 Are Not Contemporaneous with Emissions Increases from RICE Units

The *Proposed TSD* and *Proposed Permit*, discuss the proposed NOx emission cap for the RICE project for PSD netting purposes as follows:

> The Facility is voluntarily accepting a NOx emission cap to ensure that the RICE project net emissions increase for NOx is not significant. The permit requires the permanent shut down of either Unit I1 or Unit I2 (existing Units) within 180 days following initial startup of the first RICE and a requirement to permanently shut down both Units I1 and I2 within 180 days following initial startup of the sixth RICE. The NOx emission cap of 170.0 tpy applies to the ten RICE to be installed at the IGS.[28]

> The Permittee has accepted the following three separate requirements to ensure that the net emissions increase in NOx as a result of the RICE project is not significant and therefore not subject to PSD requirements:
> 1. One of the existing fossil fuel fired units (Unit 1 or Unit 2) will be shut down permanently within 180 days following initial startup of the first RICE;
> 2. Two of the existing fossil fuel fired units (Unit 1 and Unit 2) will be shut down permanently within 180 days following initial startup of the sixth RICE; and
> 3. The NOx emissions from the ten RICE will be limited to 170.0 tpy.[29]

The requirement to shut down Units I1 and I2 is incorporated into the *Proposed Permit* in Conditions B.V.E.1 and B.V.E.2.[30] The emission cap for the RICE units of

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[28] *Proposed TSD*, p. 6.

[29] *Proposed Permit*, p. 4.

[30] *Proposed Permit* in Condition B.V.E. ("1. The permittee shall shutdown permanently either Unit I1 or Unit I2 within 180 days following initial startup of the first RICE unit. 2. The permittee shall have

170.0 tons/year is incorporated into the *Proposed Permit* in Condition B.II.A.1.a. Neither the *Proposed TSD* nor the *Proposed Permit* provide any reference to an applicable legal authority for the proposed two overlap periods of 180 days between startup of the first RICE unit and shutdown of either Unit I1 or I2 and the startup of the sixth RICE unit and shutdown of both Units I1 and I2. (*See* also Comment VI.B.) Such an overlap period is inconsistent with the requirements of the Act and its implementing regulations with respect to netting for purposes of triggering PSD review.

PCC §17.04.340(A)(148) and 40 CFR §52.21(b)(3)(i)(b) provide that any increases or decreases in actual emissions at the major stationary source that are used to calculate a net emissions increase with respect to any regulated NSR pollutant[31] (here the proposed decrease of actual emission from shutdown of Units I1 and I2) must be "contemporaneous with the particular change." An increase or decrease in actual emissions is "contemporaneous" only for:

> (a) The date five years before construction on the particular change commences; and
>
> (b) The date that the increase from the particular change occurs.

PCC §17.04.340(A)(148)(b) and 40 CFR §52.21(b)(3)(ii). In sum, to be contemporaneous, shutdown of Units I1 and I2 must occur no later than the day startup of the first RICE unit occurs.

The proposed overlap period of 180 days between startup of the new RICE units and shutdown of the existing boilers may be relying on misinterpretation of PCC §17.04.340(A)(148)(g) and 40 CFR §52.21(b)(3)(viii), which allow for a "shakedown" period of 180 days for "replacement units:"

> An increase that results from a physical change at a source occurs when the emissions unit on which construction occurred becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period, not to exceed one hundred eighty days.

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shutdown permanently both Unit I1 and Unit I2 within 180 days following initial startup of the sixth RICE unit.")

[31] NOx are a regulated NSR pollutant pursuant to 40 CFR § 52.21(b)(50)(i) for which a NAAQS has been promulgated (1-hour and annual NO_2) and 40 CFR § 52.21(50)(i)(b)(1) as a precursor for ozone.

However, the RICE units are not replacement units for the steam electric generators Units I1 and I2. Since the Pima County Code does not include a definition for "replacement unit," PDEQ should look to the federal definition, and also apply a common-sense definition to define replacement unit. Notably, nowhere does the Applicant claim that the RICE project is a replacement unit.

The meaning of a "replacement unit" is defined in 40 CFR §52.21(b)(33), which requires that all of the criteria listed in the following subsections are met:

> (i) The emissions unit is a reconstructed unit within the meaning of § 60.15(b)(1) of this chapter, or the emissions unit completely takes the place of an existing emissions unit.
>
> (ii) The emissions unit is identical to or functionally equivalent to the replaced emissions unit.
>
> (iii) The replacement does not alter the basic design parameters (as discussed in paragraph (cc)(2) of this section)[32] of the process unit.
>
> (iv) The replaced emissions unit is permanently removed from the major stationary source, otherwise permanently disabled, or permanently barred from operation by a permit that is enforceable as a practical matter. If the replaced emissions unit is brought back into operation, it shall constitute a new emissions unit.

Here, the RICE units do not comply with the requirements for "replacement units" specified in in sections (ii) and (iii):

First, the RICE units are not "identical or functionally equivalent" to the existing Units I1 and I2 pursuant to 40 CFR §52.21(b)(33)(ii) as they employ fundamentally different technologies to generate electricity, *i.e.*, internal combustion versus steam turbine cycle, respectively, as recognized by the *Proposed TSD*.[33]

Second, the RICE units alter the basic design parameters of the process unit pursuant to 40 CFR §52.21(b)(33)(iii). Here, the steam turbine cycle Units I1 and I2 are

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[32] Though 40 CFR §52.21(cc)(2) is stayed indefinitely, that does not impact the remainder of 40 CFR §52.21(b)(33)(iii).

[33] *Proposed TSD*, p. 3. ("TEP-IGS currently generates electricity using two fossil fuel fired processes: (1) Steam Turbine Cycle and (2) Combustion Turbine Cycle. This PSD modification approves the construction and operation of a third fossil fuel fired process: RICE.")

permitted to fire different fuels than the RICE units and have substantially different maximum hourly heat input and maximum hourly electric output rates, as summarized in Table 1.

Table 1: Design parameters for RICE units and Unit I1 and I2

Design parameter	RICE unit	Unit I1	Unit I2
Permitted fuels	Natural gas[a]	Natural gas; fuel oil #2 through #6 or equivalent; co-firing natural gas with fuel oil #2 through #6; and co-firing any of the above fuels with landfill gas; and high sulfur oil (fuel sulfur content > 0.90% by weight) as a fuel if Permittee can demonstrate to the satisfaction of the Control Officer that sufficient quantities of low sulfur oil are not available for use by the source and that it has adequate facilities and contingency plans to ensure that the sulfur dioxide ambient air quality standards set forth in PCC 17.08.020 will not be violated[b]	Natural gas; fuel oil #2 through #6 or equivalent; co-firing natural gas with fuel oil #2 through #6; and co-firing any of the above fuels with landfill gas; and high sulfur oil (fuel sulfur content > 0.90% by weight) as a fuel if Permittee can demonstrate to the satisfaction of the Control Officer that sufficient quantities of low sulfur oil are not available for use by the source and that it has adequate facilities and contingency plans to ensure that the sulfur dioxide ambient air quality standards set forth in PCC 17.08.020 will not be violated[b]
Maximum hourly heat input	154.5 MMBtu/hr[c]	803 MMBtu/hr[d]	803 MMBtu/hr[d]
Maximum hourly electric output rate	19 MW[c]	81.02 MW[d]	81.53 MW[d]

a *Proposed Permit*, Condition B.II.A.1.a

b *Proposed Permit*, Condition B.V.A.3

c *Proposed Permit*, Attachment 2: Equipment List, VI. Reciprocating Internal Combustion Engines

d *Proposed TSD*, p. 3

Clearly, the RICE units are not "replacement units." Therefore, any emissions decreases from shutdown of Units I1 and I2, if overlapping with construction of the new RICE units, may not be used as "contemporaneous" emissions decreases in the netting analysis for the RICE project. Consequently, the RICE project results in a significant net emission increase for NOx equal to the units' combined potential to emit of 2,589.8 tons/year,[34] requiring a PSD analysis for this pollutant including an air impact analysis to determine compliance with the 1-hour and annual NO_2 national ambient air quality standards ("NAAQS") and a BACT analysis. BACT for the RICE units is 3.10 pounds per hour ("lbs/hour") of NOx, excluding startup. (*See* Comment V.A.) The *Proposed TSD* and *Proposed Permit* must be revised accordingly.

[34] *Proposed TSD*, Appx. C, Att. A, Table A-2.

B. The Proposed Phased Shutdown of Units I1 and/or I2 Does Not Support the Proposed NOx Emissions Cap for the RICE Units

Even assuming, *arguendo*, that a 180-day shakedown period applied, which it does not, the Applicant's netting analysis, upon which PDEQ relies, fails to identify that the RICE project would result in a significant net emissions increase of NOx, thus, triggering PSD review for this pollutant.

Specifically, the requirements to shut down Units I1 and I2 are incorporated into the *Proposed Permit*, Condition B.V.E, as follows:[35]

> 1. The permittee shall shutdown permanently either Unit I1 or Unit I2 within 180 days following initial startup of the first RICE unit.
> 2. The permittee shall have shutdown permanently both Unit I1 and Unit I2 within 180 days following initial startup of the sixth RICE unit.

Notably, there is no requirement that both steam turbine units be shut down should the Applicant decide to construct only five RICE units as permitted by the *Proposed Permit*, Condition B.I.N.1, which authorizes the installation of "up to ten" RICE units, and continue to operate one of the existing steam turbine cycle units, either Unit I1 or Unit I2. This scenario would permit simultaneous NOx emissions from the five RICE units and from one of the two existing steam turbine units, either Unit I1 or I2. Thus, the emission decrease assumed for shutdown of the second steam turbine cycle unit, either Unit I1 or I2, cannot be used for the RICE project to net out of PSD review. As a result, the net significant increase in NOx emissions from the five RICE units exceeds the 40 tons/year PSD significance threshold for this pollutant for the following reason:

NOx emissions from the RICE units are limited only by *Proposed Permit*, Condition B.II.A.1.a, which implements the proposed permit cap of 170.0 tons/year as a 12-month rolling total for all ten RICE units combined.[36] The *Proposed Permit* does not include any permit conditions limiting NOx emissions on an annual basis for individual

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[35] *Proposed Permit* in Condition B.V.E. ("1. The permittee shall shutdown permanently either Unit I1 or Unit I2 within 180 days following initial startup of the first RICE unit. 2. The permittee shall have shutdown permanently both Unit I1 and Unit I2 within 180 days following initial startup of the sixth RICE unit.")

[36] *Proposed Permit*, Condition B.II.A.1. ("The combined total NOx emissions from emissions units RICE01 through RICE10 shall not exceed 170.0 tons per year (tpy), based on a 12-month rolling total, calculated monthly.")

RICE units, which each have a potential to emit of 258.9 tons/year of NOx.[37] Based on the potential to emit of 258.9 tons/year, the PSD significance threshold for major modifications of 40 tons/year NOx would be exceeded when operating one RICE unit for more than 2,061.2 hours per year (23.5% of the year).[38] In fact, during a recent hearing before the Arizona Power Plant and Transmission Line Siting Committee, the Applicant indicated anticipated operation of one of the RICE units for 8,760 hours per year,[39] which would by itself result in an exceedance of the PSD significance threshold for major modifications of 40 tons/year NOx by 547 percent.[40] For all five RICE units, the PSD significance threshold for major modifications of 40 tons/year NOx would be exceeded when operating for a combined 270.7 hours per year (3.1% of the year).[41] Because the *Proposed Permit* only contains an annual emission cap for NOx emissions from all ten RICE units and no requirements to determine compliance with the major modification PSD significance threshold of 40 tons/year assumed for netting out of PSD review, this would not be detected.

Thus, unless the *Proposed Permit* is revised to include an enforceable condition to limit total combined NOx emissions from all ten RICE units to equal or less than 40 tons/year,[42] the RICE project constitutes a major modification of an existing major

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[37] *See Proposed TSD*, p. 7: potential to emit for NOx for each RICE unit is 59.1 lbs/hour; therefore, annual potential to emit for each RICE unit: (59.1 lbs/hour NOx/RICE unit) × (8,760 hours/year) / (2000 lbs/ton) = 258.9 tons/year NOx/RICE unit.

[38] (40 tons/year NOx) / (258.9 tons/year NOx/RICE unit) = 23.53%;
23.53% × (8,760 hours/year) = 2,061.2 hours/year.

[39] Before the Arizona Power Plant and Transmission Line Siting Committee, In the Matter of the Application of Tucson Electric Power Company ("TEP"), in Conformance with the Requirements of Arizona Revised Statutes §§ 40-360, et seq., for Certificates of Environmental Compatibility Authorizing the Construction of the Reciprocating Internal Combustion Engine Generation Project and the Irvington 138 kV Transmission Line Relocation Project, Including the Installation of Ten (10) Modular Approximately 20 MW Reciprocating Internal Combustion Engine Generators and Construction of Approximately 2.2 Miles of New 138 kV Transmission Lines Located Within TEP's Irvington Campus, Section 3, Township 15 South, Range 14 East, Pima County, Arizona, Docket No. L00000C-17-0365-00177, Case No. 177, January 18, 2018, p. 249; available at: https://www.tep.com/wp-content/uploads/2018/02/TEP-RICE-Project-LS_II.pdf, accessed March 28, 2018.

[40] (258.1 tons/year NOx/RICE unit) / (PSD significant modification threshold applicable to all ten RICE units: 40 tons/year NOx) = 0.647 or 647%; 647% - 100% = 547%.

[41] (258.9 tons/year NOx/RICE unit) × (5 RICE units) = 1,294.3 tons/year NOx/5 RICE units;
(40 tons/year NOx) / (1,294.3 tons/year NOx/5 RICE units) = 3.1%;
(3.1%) × (8,760 hours/year) = 270.7 hours/year.

[42] Such permit conditions to ensure compliance with a determination supporting a minor modification are included for Unit IGT3 in *Proposed Permit*, Attachments 6 and 7, Conditions III.B.1.b, respectively ("The Permittee shall not allow the total combined emissions of NOx from Unit IGT3 to equal or exceed

stationary source pursuant to PCC §17.04.340(A)(212) and 40 CFR §§52.21(b)(23), requiring PSD review including an air quality dispersion modeling analysis and a BACT analysis. A discussion of BACT for emissions of NOx from RICE units is provided in Comment V.A.

In the alternative, the *Proposed Permit* must be revised to either a) require the shutdown of both steam turbine units, Units I1 and I2, at the startup of the first RICE unit or b) include an enforceable permit condition limiting NOx emissions from each RICE unit to one tenth of the 40 tons/year significance threshold for this pollutant triggering PSD review (4 tons/year per RICE unit).

V. The Proposed Permit Fails to Establish BACT for the RICE Units

I reviewed EPA's RACT/BACT/LAER Clearinghouse ("RBLC"), the BACT Clearinghouse maintained by the California Air Resources Board ("CARB"),[43] guidance published by air districts in California and other agencies, and permits recently issued for similar equipment. My review determines a BACT limit for NOx and finds that the BACT determination supporting the *Proposed Permit* is deficient for PM10.

A. NOx BACT Normal Operations

As discussed in Comment IV, the RICE project is subject to PSD review for NOx emissions requiring BACT for this pollutant, *i.e.*, the "maximum degree of reduction" of pollution. PCC §17.04.340(A)(37); 40 CFR §52.21(b)(12). The *Proposed TSD* does not include a BACT analysis for NOx, nor does the permit include an emission rate that constitutes BACT. The most stringent emission limit for the RICE units specified in the *Proposed Permit* is the emission standard contained in Table 1 of the New Source Performance Standard ("NSPS"), Subpart JJJJ - Standards of Performance for Stationary

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40 tons per year, calculated as a 12-month rolling total. [PCC 17.12.190.B] [Material Permit Condition]"); Attachments 6 and 7, Conditions III.C.1.b, respectively ("The Permittee shall not allow the total combined emissions of SO_2 from Unit IGT3 to equal or exceed 40 tons per year, calculated as a 12-month rolling total. [PCC 17.12.190.B] [Material Permit Condition]"); and Attachments 6 and 7, Conditions III.D.1 respectively ("The Permittee shall not allow the total combined emissions of carbon monoxide (CO) from IGT3 to equal or exceed 100 tons per year, calculated as a 12-month rolling total. [PCC 17.12.190.B] [Material Permit Condition]"). (PCC §17.12.190.B requires: "The control officer shall provide public notice of receipt of complete applications for permits to construct or make a major modification to major sources by publishing a notice in a newspaper of general circulation in the county where the source will be located.")

[43] CARB, BACT Clearinghouse; available at: https://www.arb.ca.gov/bact/bactnew/rptpara.htm, accessed March 28, 2018.

Spark Ignition Internal Combustion Engines, which require compliance with a NOx emission factor of 1.0 grams per brake horsepower-hour ("g/bhp-hour") for a natural gas-fueled, non-emergency, spark-ignited, lean-burn reciprocating internal combustion engine with a maximum engine power equal to or greater than 500 horsepower ("hp"). For each of the RICE units, this is equivalent to 59.1 lbs/hour at 100 percent load.[44]

Based upon my review, the maximum emission reduction that is technically feasible to control emissions from this type of engine is SCR with lean-burn combustion. The *Proposed Permit* requires SCR for the RICE units[45] and lean burn-combustion is inherent in the design of the proposed RICE units. The most stringent BACT emission limit for non-emergency lean-burn, 4-stroke RICE units fired on pipeline natural gas, 1.45 lbs/hour, was permitted four years ago by the Kansas Department of Health and Environment ("KDHE") for a similar project, *i.e.*, the construction of ten 9-MW natural gas-fueled, non-emergency, spark-ignited, 4-stroke, lean-burn RICE units, designed to support the expansion of the wind energy resources and the oil/ gas exploration in western Kansas, at TradeWind Energy's Lacey Randall facility, northeast of Colby, Kansas.[46] The supporting BACT analysis for this facility determined, based on information from EPA's RBLC, that NOx BACT for steady-state (normal) operation is the use of SCR and an emission limit of 1.45 lbs/hour or less with an averaging period of 1 hour for each of the facility's RICE units based on vendor guarantees.[47] This

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[44] *See 12/17 Revised Application*, p. 3-3, which calculates the hourly emission rate for NOx based on an emission factor of 1.0 g/hp-hr and the nominal mechanical output capacity of each RICE unit of 26,820 hp at 59.1 lbs/hour.

[45] *Proposed Permit*, Condition II.A.1.c.

[46] *See* KDHE, Air Emission Source Construction Permit, Lacey Randall Generating Facility, LLC, Source ID 1930036, January 24, 2014 Condition VI.A. BACT Emission Limitations; available at http://www.kdheks.gov/bar/tradewind/Lacey-Randall-Final-Permit-1_24_14.pdf, accessed March 27, 2018. (Attached as Exhibit 2) ("VI.A.1. The emission of pollutants from each EGU shall be no greater than the specified limitations listed below… For the purpose of demonstrating ongoing compliance with BACT-based emission limitations, startup ends 30 minutes after a start sequence is initiated." and "VI.A.1.a. The emission of NOx shall not exceed 1.45 lbs/hour at all times except during startup (1-hour averaging period).")

[47] TradeWind Energy, Inc., Prevention of Significant Deterioration – Air Construction Permit Application, Lacey Randall Station – TradeWind Energy, Inc., Source ID 1930036, Project No. 72125, Updated December 2013 (hereafter "*Lacey Randall RICE Application*"); available at: http://www.kdheks.gov/bar/tradewind/tradewind-laceyrandall-psd-air-permit-application.pdf, accessed March 27, 2018. (Excerpts attached as Exhibit 3.) (p. 6-15: "The BACT emission limitation for NOx is 1.45 lbs/hr for steady state loads of 50 percent and higher, based on vendor guarantees. This rate is equivalent to 0.053 g/hp-hr for loads of 50 percent and higher.")

equates to an emission factor of 0.0525 g/hp-hr for each of the Lacey Randall facility's 12,526-hp RICE units.[48]

This BACT determination remains applicable to the RICE project and results in a BACT emission rate of 3.10 lbs/hour for each of the RICE units based on a NOx emission factor of 0.0525 g/bhp-hour and the nominal mechanical output capacity of 26,820 hp of each RICE unit.[49,50] The *Proposed Permit* must be revised to include a corresponding emission limit and testing, monitoring and reporting requirements.

B. PM10/PM2.5 BACT Normal Operations

The BACT analysis for PM10/PM2.5 in Attachment C to Appendix A of the *Proposed TSD* establishes BACT as good combustion practices and a non-startup PM10/PM2.5 emission limit of 2.5 lbs/hour per engine.[51] This corresponds to an emission factor of 0.04 g/hp-hr.[52] This is not BACT for a lean-burn, 4-stroke RICE unit.

A considerably lower BACT limit was permitted by the Tehama County Air Pollution Control District ("TCAPCD") and can be found in CARB's BACT Clearinghouse and the BACT determination for RICE units established by the South Coast Air Quality Management District ("SCAQMD"). Specifically, TCAPCD permitted a 44 MW peaking power plant for NEO California Power, LLC, with sixteen 3,870-hp Wartsila lean burn, 4-stroke RICE units (Model 18V220SG) fired on natural gas with a BACT emission limit of 0.02 g/hp-hr PM10, *i.e.*, half of the proposed BACT limit for the RICE project units. The engines started up in late fall of 2001, *i.e.*, more than a decade ago, and compliance with emission limits has been achieved in practiced as evidenced by source tests.[53,54] In fact, the SCAQMD's BACT determination for these units states

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[48] *Lacey Randall RICE Application*, Table 1-2, p. ES-4.

[49] *See Proposed Permit*, p. 26.

[50] (0.0525 g/hp-hr) × (26,820 hp) × (453.6 g/lb) = 3.10 lbs/hour.

[51] *Proposed TSD*, Appx. C, Att. C, pp. 6-9. ("The proposed non-startup limit of 2.5 pounds PM10/PM2.5 per hour based on three 120-minute test runs is acceptable as BACT for nonstartup operation.")

[52] (2.5 lbs/hour/RICE unit) / (26,820 hp/RICE unit) × (453.6 g/lb) = 0.04 g/hp-hr.

[53] *See* CARB, BACT Clearinghouse for Neo California Power, LLC; available at: https://www.arb.ca.gov/bact/bactnew/determination.php?var=694, accessed March 28, 2018. (Attached as Exhibit 4.)

[54] SCAQMD, Section II: Other LAER/BACT Determinations Application No. 220, Equipment Category – I.C. Engine, Stationary, Non-Emergency, May 14, 2004; available at: http://www.aqmd.gov/docs/default-source/bact/laer-bact-determinations/other-laer-bact/ice-neo-calif-power-3870-hp-an-220.pdf?sfvrsn=2. (Attached as Exhibit 5.)

that the "operating company contact reports that there has been no problem meeting the emission limits."[55]

A PM10/PM2.5 limit of 0.02 g/hp-hr is therefore equally feasible for the RICE project units. The corresponding hourly emission rate for one RICE unit is 1.18 lbs/hour.[56] The *Proposed TSD* and *Proposed Permit* must be revised to reflect this BACT emission limit for PM10/PM2.5 as an enforceable permit condition.

VI. The Proposed Permit Emission Limits Are Not Enforceable and/or Inadequate or Missing

A unit's or facility's potential to emit must be practically enforceable.[57] Practical enforceability means the source and/or enforcement authority must be able to show continual compliance (or noncompliance) with each limitation or requirement. In other words, adequate testing, monitoring, and record-keeping procedures must be included in the PSD permit for the RICE units. This requirement is not satisfied by the conditions recommended in the *Proposed Permit*.

A. Infrequent Stack Tests Are Inadequate to Determine Compliance with Proposed PSD and BACT Permit Emission Limits and Air Quality Impact Modeling

The *Proposed Permit*, Condition B.II.D.1, specifies the following testing requirements for the RICE units for compliance with PSD and BACT:

> Performance tests to demonstrate compliance with the NOx, VOC, CO, and PM10/PM2.5 emission limitations shall be conducted annually, in accordance with the following schedule. Each RICE shall be subjected to a performance test within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup. Thereafter, testing shall be conducted annually according to the following schedule: The Permittee shall conduct performance tests of at least five RICE in each calendar year, and each RICE shall be subjected to a performance test no less frequently than once in each period of two consecutive calendar years.

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[55] *Ibid*.

[56] (0.02 g/hp-hr PM10) × (26,820 hp/RICE unit) × (453.6 g/lb) = 1.18 lbs/hour PM10/RICE unit.

[57] PCC §17.04.340 (A)(175); 40 CFR §52.21(b)(17).

The *Proposed Permit* contains no testing requirements other than these infrequent stack tests (biannual after initial source test for each RICE unit) to determine compliance with the *Proposed Permit* PSD and BACT emission limits for NOx, VOC, CO, and PM10/PM2.5. Infrequent stack tests are inadequate to determine whether permit limits are being met routinely, day in and day out.[58] EPA itself has stated that annual stack tests are not sufficient to assure compliance with emissions limits.[59] The reasons for this inadequacy include the shortness of the tests, the frequency of the proposed stack testing, and the ideal, prearranged conditions under which manual stack tests are conducted.

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[58] The General Accounting Office ("GAO"), for example, has noted that stack tests "are not considered a primary detection method because they are scheduled by the facility, employ contractors paid by the facility and are performed infrequently…" *See* GAO, Report to the Chairman, Subcommittee on Oversight and Investigations, Committee on Energy and Commerce, House of Representative, *Air Pollution: Improvements Needed in Detecting and Preventing Violations*, GAO/RCES09155, September 1990, p. 12, footnote 3; http://archive.gao.gov/d22t8/142597.pdf, accessed March 27, 2018. (Attached as Exhibit 6.) ("EPA also uses stack tests to assess compliance; however, these tests are not considered a primary detection method because they are scheduled by the facility, employ contractors paid by the facility, and are performed infrequently, often only once every 6 years during permit application or renewal, according to EPA.")

[59] *See*, for example, Deborah Jordan, EPA, Letter to Jack Broadbent, Bay Area Air Quality Management District, Re: EPA Review of Proposed Title V/ Major Facility Review Permits: Chevron Products Company (Richmond) #A0010, ConocoPhillips Company #A0016 (Rodeo), Shell Oil Products US #A0011 (Martinez), Tesoro Refining and Marketing Company (Martinez) #B2758 & B2759, Valero Refining Company #B2626 (Benicia), October 8, 2004; available at: https://www3.epa.gov/region9/air/ca/sfrefineries/EPAletter-attchments.pdf, accessed March 27, 2018. (Attached as Exhibit 7.) (Explaining that annual stack testing does not ensure compliance throughout the rest of the year: "Annual testing at the ESP outlet, however, is inadequate because there is no way to determine whether the control device is operating at a level that meets the applicable requirements during the rest of the year.")

See also EPA, Letter to Howard Rhodes, Florida Department of Environmental Management, Re: EPA's Review of Proposed Title V Permit No. 0170004-004-AV Florida Power Corporation Crystal River Plant, November 1, 1999; available at https://www.epa.gov/sites/production/files/2015-07/documents/fpc.pdf, accessed March 27, 2018. (Attached as Exhibit 8.) (Specifying that the use of add-on controls requires more than annual stack testing: "While EPA has in the past accepted this approach as adequate periodic monitoring for particulate matter, it has done so only for uncontrolled natural gas and fuel oil-fired units. The units addressed in Conditions A.14. and B.13., primarily burn coal and use add-on control equipment (i.e., electrostatic precipitators) to comply with the applicable particulate matter standards. In order to provide reasonable assurance of compliance, the results of annual stack testing will have to be supplemented with additional monitoring. Furthermore, the results of an annual test alone would not constitute an adequate basis for the annual compliance certification that the facility is required to submit for these units in order to certify continuous compliance with the pound/hour particular matter limit.")

First, stack tests normally last only a few hours (two to six hours).[60] Annual testing therefore may not be representative for emissions during routine operations during the remaining hours of the year. Bi-annual testing, as proposed here is even less representative.

Second, it is well known that "[m]anual stack tests are generally performed under optimum operating conditions, and as such, do not reflect the full-time emission conditions from a source."[61] A widely used handbook on Continuous Emissions Monitoring ("CEMs") notes, with respect to manual source tests for PM10, that: "Due to the planning and preparations necessary for these manual methods, the source is usually notified prior to the actual testing. This lead time allows the source to optimize both operations and control equipment performance in order to pass the tests."[62] In other words, maintenance is performed in advance of the test to ensure that the emission-generating process is finely tuned. Sometimes, a pre-test is conducted and additional maintenance and tuning performed to assure the source passes.

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[60] *See*, for example, NSPS Subpart JJJJ, Table 2, for NOx: Results of this test consist of the average of the three 1-hour or longer runs.

[61] *See*, for example, 40 Fed. Reg. 46,241, October 6, 1975.

[62] James A. Jahnke, *Continuous Emission Monitoring*, 2nd Ed., John Wiley & Sons, Inc., New York, 2000, p. 241. (Attached as Exhibit 9.)

Therefore, to assure that sources comply with emission limits, it is essential that monitoring be performed more frequently than specified by the biannual source test requirements in the *Proposed Permit*. Stack emissions can be accurately monitored with Continuous Emissions Monitors ("CEMs"). CEMS are electro-mechanical instruments, usually installed in the facility's exhaust or smoke stacks, which sample, analyze, measure, and record the amount of pollutants passing through the stack. CEMS have been developed to measure various types of pollutants emitted by stationary sources,[63] including NOx, CO, and opacity. NOx and CO CEMS are routinely required for natural gas-fired combustion units, including RICE units,[64] and can detect violations that inspectors cannot:

> According to EPA compliance officials, inspectors have difficulty judging visible emissions at night and in adverse weather, whereas CEMS are not affected by these conditions. More importantly, gaseous emissions, such as SO, and NOx, are generally not visible, whereas CEMS consistently measure these gases directly and reliably. For some gaseous pollutants, inspectors often can only infer compliance by comparing existing process and control system operating conditions with those recorded during stack testing. However, according to EPA, stack test data are collected under finely tuned process and control system operating conditions, and thus may be atypical of tests conducted under normal operations, further adding to the difficulty of detecting violations of permit conditions for gaseous pollutants.[65]

Unless supplemental monitoring such as CEMS is added to the *Proposed Permit*, community members will not be able to protect themselves against harmful emissions and local, state, and federal regulatory agencies cannot detect and cure violations of permit conditions. Indeed, even when locals observe conditions that strongly suggest that the plant is violating its permit limits (*e.g.*, plumes are visible at the stacks, odors are present, solids settle in their yards or homes, or they experience adverse health

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[63] GAO Report, *op. cit.,* p. 17.

[64] For example, NESHAP Subpart ZZZZ, includes CO CEMS as a feasible option to determine compliance with emission limitations.

See also North Coast Unified Air Quality Management District, Title V Federal Operating Permit, NCUAQMD, Permit to Operate and Final Determination of Compliance, ATC Permit No: 443-1, April 14, 2008; available at: http://docketpublic.energy.ca.gov/PublicDocuments/Regulatory/Non%20Active%20AFC%27s/06-AFC-7%20Humboldt%20Repower/2008/April/TN%2045997%2004-14-08%20Title%20V%20Fed%20Operating%20Permit%20NCUAQMD%20Permit%20to%20Operate%20-%20FDOC.pdf, accessed March 28, 2018. (Attached as Exhibit 10.)

[65] GAO Report, *op. cit.*, pp. 19 and 20.

effects), they are often powerless to prove such violations or to stop unlawful pollution because there are no monitoring data to support their claims.

B. NOx Emissions Cap Is Not Enforceable

NOx emissions from the RICE units are limited by the *Proposed Permit*, Condition B.II.A.1.a, which implements the proposed permit emissions cap of 170.0 tons/year NOx for all ten RICE units combined based on a 12-month rolling total, calculated monthly. The *Proposed Permit* does not include any permit conditions limiting NOx emissions on a short-term basis for individual RICE units, other than the NSPS, Subpart JJJJ, emission limit of 1.0 g/bhp-hr, which results in a potential to emit of 258.9 tons/year of NOx per RICE unit.[66] The *Proposed Permit*, Condition B.II.D.2, establishes testing requirements for NOx emissions as follows:

> a. The permittee shall perform NOx emissions testing of each RICE using the methods and procedures in 40 CFR § 60.4244 and Table 2 of 40 CFR part 60, subpart JJJJ.
>
> b. Tests shall be performed at 25, 40, 70, and 100 percent of peak load or at a minimum and peak load capacity in the normal operating range of the engine, based upon the past twelve months of operation.
>
> c. The Permittee shall establish a NOx emission factor for non-startup periods expressed in lb/MMBtu heat input using the results of the most recent NOx emissions test approved by PDEQ. The emission factor for each RICE shall be set as the maximum lb/MMBtu emission factor observed during testing of such RICE under any load conditions.

Condition B.II.C.9 and B.II.C.10 lay out the reporting requirements for NOx emissions as follows:

> 9. On a monthly basis, for each RICE, the permittee shall calculate and record NOx emissions using the monthly records of heat input during periods other than startup, the NOx emission factor for non-startup periods as determined during the most recent emission test for that RICE, the number of startup events during the month, and the vendor-guaranteed NOx emission rate for each startup event. [PCC 17.12.050]
>
> 10. On a monthly basis, the permittee shall calculate and record total NOx emissions for the ten RICE, both for the most recent month and as a 12-month

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[66] (59.1 lbs/hour NOx/RICE unit) × (8,760 hours/year) / (2000 lbs/ton) = 258.9 tons/year NOx/RICE unit.

> rolling total calculated using data from the most recent month and the eleven immediately preceding months. [PCC 17.12.050]

These permit conditions are inadequate to ensure compliance with the emission cap for NOx emissions of 170.0 tons/year established in Condition B.II.A.1.a, which is therefore not enforceable.

First, the *Proposed Permit* fails to establish an unambiguous methodology for calculating NOx emissions from the emission test. Simply referring to the parameters that are part of the calculation is inadequate to ensure that the Applicant correctly calculates NOx emissions. Thus, the NOx emission cap is not enforceable. The *Proposed Permit* should be revised to include an equation that lays out the emission calculation in detail. Preferably, the *Proposed Permit* should be revised to require installation of NOx CEMS which would eliminate the need for manual calculations.

Second, one of the parameters that are part of the proposed NOx emission calculation is the "vendor-guaranteed NOx emission rate for each startup event." This emission rate is nowhere to be found in the *Proposed Permit.* Presumably, the *Proposed Permit* refers to the vendor-supplied (not vendor-guaranteed) startup emission rate of 11.1 lbs/hour of NOx per RICE unit presented in Attachment A to Appendix of the *Proposed TSD*, Table A-2. A vendor guarantee for this emission rate is nowhere to be found in the docket. Further, PDEQ recognizes that the emission rates provided by the vendor are not guaranteed. Specifically, Footnote 10 to Table A-2 clearly states "PTE emissions using vendor supplied controlled emission rates for comparative purposes only. Emissions presented are not enforceable by permit limits." Thus, the startup emission rate for NOx is not supported and, consequently, the emission cap for NOx emission from all ten RICE units is not enforceable.

C. VOC, CO, and PM10/PM2.5 Emission Limits Are Not Enforceable

The *Proposed Permit* contains testing requirements for VOC in Condition B.II.D.3, for CO in Condition B.II.D.4, and for PM10/PM2.5 in Condition B.II.D.5. Yet, the *Proposed Permit* contains no reporting requirements whatsoever for these pollutants. Thus, the emission limits for these pollutants are not enforceable.

D. Lack of Emission Limits for Potential to Emit of SO_2 and Sulfuric Acid Mist

Based on a sulfur content in pipeline natural gas of 7,500 grains per million cubic feet, the *12/17 Revised Application* determines the potential to emit of SO_2 and sulfuric acid mist ("SAM") as sulfur trioxide SO_3 for each of the RICE units at 0.32 lbs/hour and

1.4 tons/year SO_2 and 0.050 lbs/hour and 0.22 tons/year SO_3, respectively.[67] The *Proposed TSD* provides the respective potential to emit for SO_2 and SAM in Attachment A to Appendix C, Table A-1, but the *Proposed Permit* contains no corresponding emission limits for either SO_2 or SO_3 or the sulfur content in natural gas. The only related permit condition is contained in Condition B.L. Fuel Sulfur Limitations:

> Except as otherwise specified in the Specific Conditions of this permit, the Permittee shall be considered in compliance with the fuel sulfur limitations in this permit by demonstrating that only the specified fuel allowed was fired in the applicable equipment. Such a demonstration may be made by making available to the Control Officer for his inspection, documentation, such as invoices or statements from the fuel supplier, or sample analysis which verify the sulfur content of the fuel being piped and/or delivered. [PCC 17.12.180.A.3.c] [Locally Enforceable Condition]

This condition is inadequate to ensure that fuel sulfur content in natural gas is below the 7,500 grains per million cubic feet assumed for the Applicant's emission calculations upon which PDEQ relies for its potential to emit presented in summary table "*IGS Facility Wide Potential to Emit … Summary.*" Instead, the *Proposed Permit* should be revised to contain a condition specifying the maximum sulfur content in the pipeline natural gas is 7,500 grains per million cubic feet (0.75 grains/100 scf) or less demonstrated by TEP maintaining a copy of the tariff agreement approved by the Federal Energy Regulatory Commission with the same specification or less. Absent such a requirement, the visibility impact analysis for the RICE project is not supported. (*See* Comment VII.A.)

VII. PDEQ's Air Impact Analysis for the RICE Project Is Not Supported

The *Proposed TSD*, Appendix C, Attachment B, presents an *Air Impact Analysis* for the RICE project, which includes a Class II Significant Impact Modeling Analysis (Section 3.4), a PSD Class I Significant Impact Level Modeling Analysis (Section 3.5), Modeling of Ozone Precursors (Section 3.6), and a Visibility Analysis (Section 3.7.1). These analyses are flawed, and the modeled results are not supported.

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[67] *See 12/17 Revised Application*, pp. 3-1 and 3-2.

A. PDEQ's Visibility Impact Analysis for Saguaro National Park Is Not Supported and Underestimates Visibility Impacts

Pursuant to 40 CFR §52.21(o)[68] and PCC § 17.16.630, the *Proposed TSD*, Appendix C, Attachment B, Chapter 3.7.1, presents an analysis of the anticipated impacts on visibility due to emissions from the proposed RICE project at nearby federal Class I areas, specifically, at Saguaro National Park (East and West).[69] Both PDEQ and the National Park Service ("NPS") determined that the RICE project would have a negative impact on visibility at Saguaro National Park as modeled. However, as discussed below, the modeling runs by far underestimate visibility impacts because the modeled NOx emission rates are not consistent with the potential to emit for the RICE units.

Modeling Approach

PDEQ modeled potential impacts with PLUVUE II, a refined visibility model designed to predict the transport, atmospheric diffusion, chemical conversion, optical effects, and surface deposition of point and area sources. The objective of the PLUVUE II model is to calculate visual range reduction and atmospheric discoloration caused by plumes consisting of primary particles, NOx, and sulfur dioxides ("SOx"), emitted by a single emission source.[70]

PDEQ modeled visibility impacts at Saguaro National Park with PLUVUE II for the following two cases:

Case 1: maximum 1-hour average emissions accounting for simultaneous start-up of all 10 RICE units within 30 minutes, plus 30 minutes running at 100% load in the same hour; and

Case 2: emissions from all 10 RICE units at 100% load.[71]

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[68] 40 CFR §52.21(o)(1). ("The owner or operator shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.")

[69] *Proposed TSD*, Appx. C, Att. B, Chapter 3.7.1, pp. 17-20.

[70] *Proposed TSD*, Appx. C, Att. B, Chapter 3.7.1, p. 17.

[71] *Proposed TSD*, Appx. C, Att. B, Chapter 3.7.1, p. 18.

The *Proposed TSD* fails to provide information on the modeled emission rates. Presumably, PDEQ modeled the same emission rates as those presented by the Applicant in the December 22, 2017 *Final Air Quality Dispersion Modeling Protocol*,[72] Chapter 5.1 Visibility Analysis (within 50 kilometers). The corresponding combined short-term emission rates for all ten RICE units are shown in the excerpted table from the December 22, 2017 *Final Air Quality Dispersion Modeling Protocol*.[73]

Table 2-1 Emissions Summary for All Ten RICE Units (pounds per hour)

Pollutant	Case 1	Case 2
PM	29.85	23.70
NOx	110.50	15.00
SO_2	3.20	3.20

Modeling Results

Based on the PLUVUE II modeling as discussed above, the *Proposed TSD* finds adverse impacts on visibility at Saguaro National Park for *Case I* (0.59% of daytime hours assuming grey as background color and 0.82% assuming black as background color) and for *Case II* (0.52% of daytime hours assuming grey as background color and 0.70% assuming black as background color).[74] The NPS reran the PLUVUE II modeling with the same emission rates for *Case I*[75] and found "visibility impacts at Saguaro east and west."[76] Specifically, the NPS determined:

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[72] *See* TEP, Air Quality Dispersion Modeling Report in Support of the Application for a Prevention of Significant Deterioration (PSD) Authorization and Significant Revision to Class I Air Quality Permit for Irvington Generating Station, prepared by AECOM, Revision 2, December 22, 2017 (hereafter "*12/17 TEP Air Quality Modeling Report*"), Section 4.8, pp. 4-9 and 4-10; available at: http://webcms.pima.gov/UserFiles/Servers/Server_6/File/Government/Environmental%20Quality/Air/TEP%20PSD%20Webpage/17-12-22-TEP-IGS-Modeling-Report.pdf, accessed March 27, 2018.

[73] *Ibid*, Appx. C, p. 8.

[74] *Proposed TSD*, Appx. C, Att. B, Chapter 3.7.1, p. 20.

[75] The NPS indicates modeled emission rates of 0.04 tons/day SO_2, 1.33 tons/day NOx, and 0.36 tons/day PM, which is equivalent to 3.3 lbs/hour SO_2, 110.5 lbs/hour NOx, and 30.0 lbs/hour PM. *See* Email from Kirsten King, NPS, to Rupesh Patel, PDEQ, Re: Tucson Electric Power, February 8, 2018, 1:37 pm.

[76] Email from Kirsten King, NPS, to Rupesh Patel, PDEQ, Re: Tucson Electric Power, February 8, 2018, 1:37 pm; available at http://webcms.pima.gov/UserFiles/Servers/Server_6/File/Government/Environmental%20Quality/Air/TEP%20PSD%20Webpage/NPS-Review-and-Response-to-Visibility-Modelling-and-Proposed-Permit.pdf, accessed March 28, 2018.

> Saguaro east would see 13 hours per year with the highest Delta E of 4.658 and a Cp of 0.184. Saguaro west will see 48 hours per year with the highest Delta E of 9.612 and a Cp of 0.413.
>
> Based on the PLUVUE model, out of a total of 4,380 daylight hours per year, there will be, on average, 61 hours per year when a plume might be perceptible within the park.[77]

The guidance that FLMs rely on to determine significance for visibility impacts, FLAG 2010, notes that for PLUVUE II analyses, the FLM would likely not object if Delta E is lower than 1.0 and Cp is lower than < 0.02.[78]

In other words, both PDEQ and the NPS determine that the RICE project would have an adverse impact on visibility at Saguaro National Park as modeled. However, these modeled adverse impacts, as discussed below, by far underestimate visibility impacts due to emissions from the RICE units.

Modeled NOx Emission Rates Are Not Supported

The *Proposed Permit* does not contain any permit conditions for the RICE units limiting short-term NOx emission rates to the modeled short-term emission rates and the modeled NOx rates are much lower than the combined potential to emit. Specifically, as shown in the excerpted table from the December 22, 2017 *Final Air Quality Dispersion Modeling Protocol* above, the modeled worst-case emission rates are 110.50 lbs/hour NOx for *Case 1* (30 minutes startup + 30 minutes normal operation) for all ten RICE Units or 11.05 lbs/hour NOx per RICE unit, and 15.00 lbs/hour NOx for *Case 2* (60 minutes normal operation) for all ten RICE units, or 1.50 lbs/hour NOx per RICE unit. These emission rates are considerably lower than those indicated as potential to emit in the Proposed TSD of 59.1 lbs/hour NOx for one RICE unit, *i.e.*, 590.1 lbs/hour NOx combined for all ten RICE units.

Thus, the results of the PLUVUE II modeling are not supported and the *Proposed Permit* does not ensure compliance with the modeled impacts. (In contrast, to ensure compliance with the air quality dispersion modeling analysis for PM10 and

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[77] *Ibid*.

[78] U.S. Forest Service, National Park Service, and U.S. Fish and Wildlife Service, Federal Land Managers' Air Quality Related Values Work Group (FLAG), Phase I Report—Revised (2010), Natural Resource Report NPS/NRPC/NRR—2010/232, October 2010, p. 21; available at https://www.nature.nps.gov/air/Pubs/pdf/flag/FLAG_2010.pdf, accessed March 26, 2018. (Attached as Exhibit 11.) ("For PLUVUE II analyses, the FLM would likely not object if $\Delta E < 1.0$ and $|C| < 0.02$.")

PM2.5, which determines compliance with the respective short-term (24-hour) NAAQS for these pollutants, the *Proposed TSD* requires, and the *Proposed Permit* incorporates, the modeled emission rate as a permit condition.[79,80])

Permit Revision Required

The *Proposed Permit* must be revised to include a permit condition limiting short-term emission rates to the modeled emission rates described above. Alternatively, the PLUVUE II modelling must be rerun with the potential to emit for all 10 RICE units of 591.0 lbs/hour of NOx. This would more accurately reflect visibility impacts from the RICE project absent any permit conditions limiting short-term NOx emissions from the RICE units, which would be considerably more severe than determined by PDEQ and NPS. The Federal Land Manager must have an opportunity to review the updated modeling and consider whether the project will adversely impact visibility.

B. PDEQ's Class II Significant Impact Modeling Analysis for CO, PM10, and PM2.5 Is Not Supported

The *Proposed TSD* determines compliance with short-term NAAQS for CO, PM10 and PM2.5 based on "average emission rates." These average emission rates are summarized in Tables 3-5 and 3-6 of Attachment B to Appendix C of the *Proposed TSD*. PDEQ modeled the 1-hour and 8-hour CO concentrations based on the startup emission rate for this pollutant of 18.2 lbs/hour provided by the vendor.[81] PDEQ modeled the 24-hour PM10 and PM2.5 concentrations based on 24-hour average emission rates calculated based on 21.5 hours of operation at the vendor-supplied emission rate including a buffer five startups per day.[82] As discussed in Comment VI.B, the vendor-supplied emission rates are not guaranteed and are not required as enforceable permit

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[79] *Proposed TSD*, p. 12. ("PM10/PM2.5 BACT for the RICE is determined to be 2.5 pounds PM10/PM2.5 per hour for non-startup operation. PM10/PM2.5 BACT for startup is: 1) minimize time spent at idle, 2) 30-minute startup duration limit, and 3) operation according to manufacturer specifications for minimizing emissions. Although 2.5 lbs/hr is deemed BACT for non-startup operation, the PM10/PM2.5 emission limit in the permit (2.37 lbs/hr) is based on the BACT determination and the dispersion modeling analysis. The dispersion modeling analysis includes startup emissions and requires an emission limit of 2.37 lbs/hr to demonstrate compliance (see Attachment B of Appendix C for details.)" Emphasis retained.)

[80] *Proposed Permit*, Condition B.II.A.4.a: PM10/PM2.5 emissions from each emissions unit (RICE01 through RICE10) shall not exceed 2.37 lbs/hr, excluding periods of startup.

[81] *Proposed TSD*, Appx. C, Att. B, Table 3-5, p. 9, Footnote 1.

[82] *Proposed TSD*, Appx. C, Att. B, Table 3-5, p. 9, Footnote 2.

conditions. Thus, the results of PDEQ's Class II significant impact modeling analysis is not supported. Instead, modeling must be based on the maximum emission rates incorporated into an enforceable permit condition.

C. Modeling of Secondary PM2.5 Emissions Is Required to Determine Compliance with the PM2.5 NAAQS

The *Proposed TSD* fails to address the requirement for modeling of secondary PM2.5 emissions, presumably based on the Applicant's erroneous finding that such modeling is not required.[83] Modeling of secondary PM2.5 emissions is required based on EPA guidance, and PDEQ must model the secondary PM2.5 emissions to properly demonstrate compliance with the PM2.5 NAAQS.

Specifically, the Applicant discusses the May 20, 2014 guidance from EPA regarding PM2.5 modeling for permitting purposes,[84] which defines four cases for what type of air quality modeling analysis is needed for consideration of direct and secondary PM2.5 emissions, as shown in the following excerpted table.

Table ES-1. EPA Recommended Approaches for Assessing Primary and Secondary $PM_{2.5}$ Impacts by Assessment Case

Assessment Case	Description of Assessment Case	Primary Impacts Approach	Secondary Impacts Approach
Case 1: No Air Quality Analysis	Direct PM2.5 emissions < 10 tpy SER NOx and SO2 emissions < 40 tpy SER	N/A	N/A
Case 2: Primary Air Quality Impacts Only	Direct PM2.5 emissions ≥ 10 tpy SER NOx and SO2 emissions < 40 tpy SER	Appendix W preferred or approved alternative dispersion model	N/A
Case 3: Primary and Secondary Air Quality Impacts	Direct PM2.5 emissions ≥ 10 tpy SER NOx and/or SO2 emissions ≥ 40 tpy SER	Appendix W preferred or approved alternative dispersion model	• Qualitative • Hybrid qualitative / quantitative • Full quantitative photochemical grid modeling
Case 4: Secondary Air Quality Impacts Only	Direct PM2.5 emissions < 10 tpy SER NOx and/or SO2 emissions ≥ 40 tpy SER	N/A	• Qualitative • Hybrid qualitative / quantitative • Full quantitative photochemical grid modeling

[83] *See TEP Air Quality Dispersion Modeling Report*, p. 4-10.

[84] Stephen Page, EPA, Memorandum to Regional Air Division Directors, Regions 1-10, Re: Guidance for PM2.5 Permit Modeling, May 20, 2014 (hereafter "EPA PM2.5 Modeling Guidance"); available at: https://www3.epa.gov/scram001/guidance/guide/Guidance_for_PM25_Permit_Modeling.pdf, accessed March 27, 2018. (Attached as Exhibit 12.)

The Applicant finds that PM2.5 modeling for the RICE project falls into Case 2, *i.e.*, direct PM2.5 emissions are equal to or greater than the 10 tons/year significant emission rate ("SER") for this pollutant and NOx and/or SO_2 emission rates are less than the respective 40 tons/year SER for these pollutants, thus, concludes that an analysis to address secondary PM2.5 impacts is not required.[85]

However, as demonstrated in Comment IV, the RICE project in the *Proposed Permit* would exceed the 40 tons/year SER for NOx emissions; thus, Case 3 applies, *i.e.*, direct PM2.5 emissions are equal to or greater than the 10 tons/year SER for this pollutant and NOx and/or SO_2 emission rates are less than the respective 40 tons/year SER for these pollutants. For Case 3, EPA guidance recommends an analysis to address secondary PM2.5 impacts. The *Proposed Permit* and *Proposed TSD* should be revised to include such an analysis.

D. The Proposed TSD Fails to Provide Modeling for Compliance with National Ambient Air Quality Standards for NO_2

As discussed in Comment IV, the RICE project would result in a significant net emission increase for NOx, which requires dispersion modeling for demonstrating compliance with the short-term and annual NAAQS for NO_2. The *Proposed TSD* must be revised to include such an analysis.

VIII. Typographical and Other Errors in the Proposed TSD

The *Proposed TSD* and *Proposed Permit* contain a number of typographical and other errors, as discussed below.

A. The Facility-wide Potential to Emit Presented in the Proposed TSD Is Incorrect

The *Proposed TSD*, p. 7, presents a summary table, *IGS Facility Wide Potential to Emit … Summary*, which totals emissions unit-specific and Facility-wide hourly and annual PTE:

– The Facility-wide annual PTE for NOx, presented in the *IGS Facility Wide Potential to Emit … Summary* table, **4,886.1 tons/year**, is incorrectly totaled; instead the correct Facility-wide annual PTE for NOx is **4,877.1 tons/year**.

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[85] *12/17 TEP Air Quality Modeling Report*, pp. 4-9 - 4-10.

It appears that the Facility-wide annual PTE in the summary table was not updated to account for the proposed lower permit limit cap for NOx emissions from all ten RICE Units of 170.0 tons/year, a decrease of 8.96 tons/year compared to the previously proposed 178.96 tons/year.[86]

- The hourly and annual PTE for CO_2e for each of the 10 RICE units presented in the *IGS Facility Wide Potential to Emit … Summary* table, **1.85E05 lbs/hr** and **7.9E05 tpy**, are an order of magnitude too high. Instead, according to the *12/17 Revised Application*, the correct hourly and annual PTE for CO_2e for each of the ten RICE units are **1.85E+04 lbs/hr** and **7.92E+04 tpy**.[87]
- The Facility-wide annual PTE for CO_2e, presented in the *IGS Facility Wide Potential to Emit … Summary* table, **3,822,500 tons/year**, is incorrectly totaled. Instead, the correct Facility-wide annual PTE for CO_2e is calculated at **3,833,682 tons/year** when accounting for the revised hourly and annual PTE for CO_2e for each of the ten RICE units, as discussed above.

B. The Proposed TSD Fails to Correctly Identify National Ambient Air Quality Standards and Class II Significant Impact Levels

The Proposed TSD contains several errors regarding the applicable NAAQS and Class II SILs:

- The *Proposed TSD*, Appendix C, Attachment B: *Air Quality Impact Analysis*, Table 3-2, incorrectly provides the 1-hour NAAQS for CO as 358 parts per million ("ppm") instead of 35 ppm.[88]
- The *Proposed TSD*, Appendix C, Attachment B: *Air Quality Impact Analysis*, Table 3-1, incorrectly identifies the annual NAAQS for PM2.5 as 15 $\mu g/m^3$ instead of 12 $\mu g/m^3$.[89]
- The *Proposed TSD*, Appendix C, Attachment B: *Air Quality Impact Analysis*, Table 3-1, incorrectly identifies the Class II SIL for 24-hour PM2.5 as 0.3 $\mu g/m^3$ instead of 0.2 $\mu g/m^3$.[90]

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[86] *See*, *12/17 Revised Application*, pp. 3-3, 3-7, 4-6, 4-10, and 4-11, and Appx. B, pp. B-2 and B-4 (179.0 tons/year); and Conrad Spencer, TEP, Letter to Rupesh Patel, PDEQ, February 23, 2018, *op. cit.*

[87] *12/17 Revised Application*, p. 3-5, Table 3-1: GHG PTE for Each RICE.

[88] *See* U.S. EPA, NAAQS Table; available at: https://www.epa.gov/criteria-air-pollutants/naaqs-table, accessed March 18, 2018. (Attached as Exhibit 13).

[89] *Id*.

C. The Proposed TSD Must be Revised to Reflect the Proposed Emission Cap for NOx Emissions for the RICE Units

The *Proposed TSD*, Appendix C, Attachment A, provides emission calculations for the RICE project. Table A-1: Proposed RICE Project Potential to Emit (PTE) provides the potential to emit for the RICE project, *i.e.*, the ten RICE units and auxiliary equipment, at 170.0 tons/year for NOx. Note 1 to Table A-1 and Note 11 to Table A-2 provide that this proposed NOx emission limit is included in TEP's *12/17 Revised Application*.[91] This is incorrect, the *12/17 Revised Application* provides the potential to emit for the RICE project at 179.0 tons/year.[92] The proposed 170.0 tons/year emission cap for NOx emissions from the RICE project is contained in the Applicant's February 23, 2018 letter to PDEQ.[93] The *Proposed TSD* must be revised accordingly.

IX. Conclusion and Recommendation

As discussed in my comments above, the *Proposed TSD* is substantially flawed and the *Proposed Permit* is not consistent with the requirements of the Act and its implementing regulations and should be revised to address the above discussed issues.

With best regards,

Petra Pless, D.Env.

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[90] *Id*.

[91] *Proposed TSD*, Appx. C, Att. A, Table A-1, Note 1. ("Proposed NOx emission limit for all 10 RICE included in TEP Application for a Prevention of Significant Deterioration (PSD) Authorization and Significant Revision to Class I Air Quality Permit for Irvington Generating Station, Revised December 2017.")

[92] *See 12/17 Revised Application*, pp. 3-3, 3-7, 4-6, 4-10, and 4-11 and Appx B, pp. B-2 and B-4.

[93] Conrad Spencer, TEP, Letter to to Rupesh Patel, PDEQ, February 23, 2018, *op. cit.*

EXHIBIT 1

to Sierra Club Comments

Petra Pless, D.Env.

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Dr. Pless has over 15 years of experience in environmental engineering and science conducting and managing interdisciplinary environmental research projects and preparing and reviewing environmental permits and other documents for U.S. and European stakeholder groups. This broad-based experience includes air quality and air pollution control; water quality, water supply, and water pollution control; biology; public health and safety; and noise studies. National Environmental Policy Act ("NEPA"), California Environmental Quality Act ("CEQA"), and Clean Air Act ("CAA") review; industrial ecology and risk assessment; and use of a wide range of environmental software.

EDUCATION

Doctorate in Environmental Science and Engineering (D.Env.), University of California, Los Angeles, 2001

M.S. Biology (with focus on botany/ecology/limnology), Technical University of Munich, Germany, 1991

PROFESSIONAL HISTORY

Environmental consultant 2006–present

Leson & Associates (previously Leson Environmental Consulting), Kensington, CA, Environmental Scientist/Project Manager, 1997–2005

University of California Los Angeles, Graduate Research Assistant/Teaching Assistant, 1994–1996

ECON Research and Development, Environmental Scientist, Ingelheim, Germany, 1992–1993

Biocontrol, Environmental Projects Manager, Ingelheim, Germany, 1991–1992

REPRESENTATIVE EXPERIENCE

Air Quality and Pollution Control

Projects include CEQA/NEPA review; attainment and non-attainment new source review ("NSR"), prevention of significant deterioration ("PSD") and Title V permitting; control technology analyses (BACT, LAER, RACT, BARCT, MACT); technology evaluations and cost-effectiveness analyses; criteria and toxic pollutant emission inventories; emission offsets; ambient and source monitoring; analysis of emissions estimates and ambient air pollutant concentration modeling. Some typical projects include:

- Critically reviewed and prepared technical comments on the air quality, biology, noise, water quality, and public health and safety sections of CEQA/NEPA documents for numerous commercial, residential, and industrial projects (*e.g.*, power plants, airports, residential developments, retail developments, hospitals, refineries, slaughterhouses, quarries, and mines).
- Critically reviewed and prepared technical comments on the air quality and public health sections of the Los Angeles Airport Master Plan (Draft, Supplement, and Final Environmental Impact Statement/Environmental Impact Report) for the City of El Segundo. Provided technical comments on the Draft and Final General Conformity Determination for the preferred alternative submitted to the Federal Aviation Administration.
- For several California refineries, evaluated compliance of fired sources with Bay Area Air Quality Management District ("BAAQMD") Rule 9-10. This required evaluation and review of hundreds of source tests to determine if refinery-wide emission caps and compliance monitoring provisions were being met.
- Critically reviewed and prepared technical comments on Draft Title V permits for several refineries and other industrial facilities in California.
- Reviewed state-wide average emissions, state-of-the-art control devices, and emissions standards for construction equipment and developed recommendations for mitigation measures for numerous large construction projects.
- Researched sustainable building concepts and alternative energy and determined their feasibility for residential and commercial developments, *e.g.*, regional shopping malls and hospitals.
- Evaluated the public health impacts of locating big-box retail developments in densely populated areas in California and Hawaii. Monitored and evaluated impacts of diesel exhaust emissions and noise on surrounding residential communities.
- In conjunction with the permitting of several residential and commercial developments, conducted studies to determine baseline concentrations of diesel exhaust particulate matter using an aethalometer.
- For an Indiana steel mill, evaluated technology to control NOx and CO emissions from fired sources, including electric arc furnaces and reheat furnaces, to establish BACT. This required a comprehensive review of U.S. and European operating experience. The lowest emission levels were being achieved by steel mills using selective catalytic reduction ("SCR") and selective non-catalytic reduction ("SNCR") in Sweden and The Netherlands.
- For a California petroleum coke calciner, evaluated technology to control NOx, CO, VOCs, and PM10 emissions from the kiln and pyroscrubbers to establish BACT and LAER. This required a review of state and federal clearinghouses, working with regulatory agencies and pollution control vendors, and obtaining and reviewing permits and emissions data from other similar facilities. The best-controlled facilities were located in the South Coast Air Quality Management District ("SCAQMD").
- For a Kentucky coal-fired power plant, identified the lowest NOx levels that had been permitted and demonstrated in practice to establish BACT. Reviewed operating experience of European, Japanese, and U.S. facilities and evaluated continuous emission monitoring data.

The lowest NOx levels had been permitted and achieved in Denmark and in the U.S. in Texas and New York.

- In support of efforts to lower the CO BACT level for power plant emissions, evaluated the contribution of CO emissions to tropospheric ozone formation and co-authored report on same.
- Critically reviewed and prepared technical comments on applications for certification ("AFCs") for numerous natural-gas fired and geothermal power plants in California permitted by the California Energy Commission ("CEC"). The comments addressed construction and operational emissions inventories and dispersion modeling, BACT determinations for combustion turbine generators, etc.
- Critically reviewed and prepared technical comments on draft PSD permits for several natural gas-fired power plants in California, Indiana, and Oregon. The comments addressed emission inventories, BACT, case-by-case MACT, compliance monitoring, cost-effectiveness analyses, and enforceability of permit limits.
- For a California refinery, evaluated technology to control NOx and CO emissions from CO Boilers to establish RACT/BARCT to comply with BAAQMD Rule 9-10. This required a review of BACT/RACT/LAER clearinghouses, working with regulatory agencies across the U.S., and reviewing federal and state regulations and State Implementation Plans ("SIPs"). The lowest levels were required in a SCAQMD rule and in the Texas SIP.
- In support of several federal lawsuits filed under the Clean Air Act, prepared cost-effectiveness analyses for SCR and oxidation catalysts for simple cycle gas turbines and evaluated opacity data.
- Critically reviewed draft permits for several ethanol plants in California, Indiana, and Ohio and prepared technical comments.
- Provided comprehensive environmental and regulatory services for an industrial laundry chain. Facilitated permit process with the SCAQMD. Developed test protocol for VOC emissions, conducted field tests, and used mass balance methods to estimate emissions. Reduced disposal costs for solvent-containing waste streams by identifying alternative disposal options. Performed health risk screening for air toxics emissions. Provided permitting support with SCAQMD. Renegotiated sewer surcharges with wastewater treatment plant. Identified new customers for shop-towel recycling services.
- Designed computer model to predict performance of biological air pollution control (biofilters) as part of a collaborative technology assessment project, co-funded by several major chemical manufacturers. Experience using a wide range of environmental software, including air dispersion models, air emission modeling software, database programs, and geographic information systems ("GIS").

Water Quality and Pollution Control

Experience in water quality and pollution control, including surface water and ground water quality and supply studies, evaluating water and wastewater treatment technologies, and identifying, evaluating and implementing pollution controls. Some typical projects include:

- For a homeowner's association, reviewed a California Coastal Commission staff report on the replacement of 12,000 linear feet of wooden bulkhead with PVC sheet pile armor. Researched and evaluated impact of proposed project on lagoon water quality, including sediment resuspension, potential leaching of additives and sealants, and long-term stability. Summarized results in technical report.
- For a 500-MW combined-cycle power plant, prepared a study to evaluate the impact of proposed groundwater pumping on local water quality and supply, including a nearby stream, springs, and a spring-fed waterfall. The study was docketed with the CEC and summarized in a journal article.
- Evaluated impacts of on-shore oil drilling activities on large-scale coastal erosion in Nigeria.
- For a 500-MW combined-cycle power plant, identified and evaluated methods to reduce water use and water quality impacts. These included the use of zero-liquid-discharge systems and alternative cooling technologies, including dry and parallel wet-dry cooling. Prepared cost analyses and evaluated impact of options on water resources. This work led to a settlement in which parallel wet dry cooling and a crystallizer were selected, replacing 100 percent groundwater pumping and wastewater disposal to evaporation ponds.

Applied Ecology, Industrial Ecology and Risk Assessment

Experience in applied ecology, industrial ecology and risk assessment, including human and ecological risk assessments, life cycle assessment, evaluation and licensing of new chemicals, and fate and transport studies of contaminants. Experienced in botanical, phytoplankton, and intertidal species identification and water chemistry analyses. Some typical projects include:

- For the California Coastal Conservancy, San Francisco Estuary Institute, Invasive Spartina Project, evaluated the potential use of a new aquatic pesticide for eradication of non-native, invasive cordgrass (*Spartina spp.*) species in the San Francisco Estuary with respect to water quality, biological resources, and human health and safety. Assisted staff in preparing an amendment to the Final EIR.
- Evaluated likelihood that measured organochlorine pesticide concentrations at a U.S. naval air station are residuals from past applications of these pesticides consistent with manufacturers' recommendations. Retained as expert witness in lawsuit.
- Prepared human health risk assessments of air pollutant emissions from several industrial and commercial establishments, including power plants, refineries, and commercial laundries.
- Managed and conducted studies to license new pesticides. This work included the evaluation of the adequacy and identification of deficiencies in existing physical/chemical and health effects data sets, initiating and supervising studies to fill data gaps, conducting environmental fate and transport studies, and QA/QC compliance at subcontractor laboratories. Prepared licensing applications and coordinated the registration process with German licensing

agencies. This work led to regulatory approval of several pesticide applications in less than six months.

- Designed and implemented database on physical/chemical properties, environmental fate, and health impacts of pesticides for a major European pesticide manufacturer.
- Designed and managed toxicological study on potential interference of delta-9-tetrahydro-cannabinol in food products with U.S. employee drug testing; co-authored peer-reviewed publication.
- Critically reviewed and prepared technical comments on AFCs for several natural-gas fired and geothermal power plants and transmission lines in California permitted by the CEC. The comments addressed avian collisions and electrocution, construction and operational noise impacts on wildlife, risks from brine ponds, and impacts on endangered species.
- For a 180-MW geothermal power plant, evaluated the impacts of plant construction and operation on the fragile desert ecosystem in the Salton Sea area. This work included baseline noise monitoring and assessing the impact of noise, brine handling and disposal, and air emissions on local biota, public health, and welfare.
- Designed research protocols for a coastal ecological inventory; developed sampling methodologies, coordinated field sampling, determined species abundance and distribution in intertidal zone, and analyzed data.
- Designed and conducted limnological study on effects of physical/chemical parameters on phytoplankton succession; performed water chemistry analyses and identified phytoplankton species; co-authored two journal articles on results.
- Conducted technical, ecological, and economic assessments of product lines from agricultural fiber crops for European equipment manufacturer; co-authored proprietary client reports.
- Developed life cycle assessment methodology for industrial products, including agricultural fiber crops and mineral fibers; analyzed technical feasibility and markets for thermal insulation materials from plant fibers and conducted comparative life cycle assessments.
- Conducted and organized underwater surveying and mapping of plant species in several lakes and rivers in Sweden and Germany as ecological indicators for the health of limnological ecosystems.

PRO BONO ACTIVITIES

Founding member of "SecondAid," a non-profit organization providing tsunami relief for the recovery of small family businesses in Sri Lanka. (www.secondaid.org)

PROFESSIONAL AFFILIATIONS

Association of Environmental Professionals

SELECTED PUBLICATIONS

Leson G. and Pless P., Hemp seeds and hemp oil, in: Grotenhermen F. and Russo E. (eds.), Cannabis und Cannabinoids, Pharmacology, Toxicology, and Therapeutic Potential, The Haworth Integrative Healing Press, New York, 2002.

Leson G., Pless P., Grotenhermen F., Kalant H., and ElSohly M., Evaluating the impact of hemp food consumption on workplace drug tests, Journal of Analytical Toxicology, Vol. 25, No. 11/12, pp. 1-8, 2001.

Leson G. and Pless P., Assessing the impact of THC uptake from hemp oil cosmetics on workplace drug testing, Report to the Agricultural Research and Development Initiative ("ARDI"), Morris, MB, 2001.

Pless P., Technical and environmental assessment of thermal insulation materials from fiber crops, doctoral dissertation in Environmental Science and Engineering, University of California, Los Angeles, 2001.

Center for Waste Reduction Technologies in the American Institute of Chemical Engineers, Collaborative Biofilter Project, Technical Report, co-author with Leson G. of sections 'Compound Database,' 'Design Manual,' and 'Literature Database,' 1998.

Hantke B., Domany I., Fleischer P., Koch M., Pless P., Wiendl M., and Melzer M., Depth profiles of the kinetics of phosphatase activity in hardwater lakes of different trophic level, Arch. Hydrobiologia, vol. 135, pp. 451–471, 1996.

Hantke B., Fleischer P., Domany I., Koch M., Pless P., Wiendl M., and Melzer M., P-release from DOP by phosphatase activity in comparison to P-excretion by zooplankton: studies in hardwater lakes of different trophic level, Hydrobiologia, vol. 317, pp. 151–162, 1996.

Pless P., Untersuchungen zur Phytoplanktonentwicklung im Herrensee (investigations on phytoplankton succession in an oligotrophic hardwater lake), Masters Thesis in biology with focus on botany/ecology/limnology, Technical University of Munich, Germany, 1991.

EXHIBIT 2

to Sierra Club Comments

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Robert Moser, MD, Secretary

Department of Health & Environment

Sam Brownback, Governor

AIR EMISSION SOURCE CONSTRUCTION PERMIT

Source ID No.: 1930036

Effective Date: January 24, 2014

Source Name: Lacey Randall Generation Facility, LLC

SIC Code: 4911, Electric Services

NAICS Code: 221112, Fossil Fuel Power Generation

Source Location: Southwest Quarter of Section 17, Township 7 South, Range 33 West
Thomas County, Kansas

Owner Name: Tradewind Energy, Inc.

Owner Mailing Address: 16105 W. 113th Street, Suite 105
Lenexa, Kansas 66219

Contact Person: Jennifer A. Dean
Director of Environmental Studies and Permitting
Telephone: (913) 219-5004
jdean@tradewindenergy.com

This permit is issued pursuant to K.S.A. 65-3008 as amended.

I. Description of Activity Subject to Air Pollution Control Regulations

Tradewind Energy, Inc. plans to install up to ten new spark ignition Wartsila four stroke lean burn reciprocating internal combustion engine (RICE) electric generating units (EGUs) plus auxiliary equipment at the Lacey Randall Station (the Project) to be located in Thomas County, Kansas, approximately 3.5 miles northeast of Colby, Kansas. The Project will have a total nominal power output of approximately 94 megawatts (MW) and will be fired by pipeline quality natural gas. The facility will also include a 3 million Btu per hour (MMBtu/hr) gas heater, a 150 horsepower (hp) emergency fire pump, a 324 hp emergency diesel generator, up to 4 circuit breakers, and a 309,000 gallon fuel oil storage tank. The Project is designed to support the expansion of the wind energy resources and the oil/gas exploration in western Kansas.

The potential emissions of oxides of nitrogen (NO_X), carbon monoxide (CO), sulfur dioxide (SO_2), volatile organic compounds (VOCs), particulate matter (PM), PM less than 10 microns (PM_{10}), and hazardous air pollutants (HAPs) have been reviewed and the proposed project is subject to the provisions of **K.A.R. 28-19-300 (Construction permits and approvals; applicability)** because the potential emissions for NO_X, VOC, CO, PM, PM_{10}, and HAPs are above the permitting thresholds.

The Project is subject to the provisions of **K.A.R. 28-19-720, New Source Performance Standards** (NSPS). The emergency fire pump and emergency diesel generator are subject to the requirements of 40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition (CI) Internal Combustion Engines. The RICE EGUs are subject to the requirements of 40 CFR Part 60, Subpart JJJJ, Standards of Performance for Stationary Spark Ignition (SI) Internal Combustion Engines.

The Project is subject to the provisions of **K.A.R. 28-19-750, Hazardous air pollutants; maximum achievable control technology**, because the estimated potential–to-emit (PTE) of HAPs from the facility is greater than 10 tons annually for a single HAP, and the estimated PTE of all HAPs in the aggregate is greater than 25 tons/year. All engines are subject to 40 CFR Part 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines. The gas heater is subject to 40 CFR Part 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.

On November 29, 2010, **K.A.R. 28-19 350, Prevention of Significant Deterioration (PSD) of Air Quality, which adopts by reference 40 CFR Part 52.21,** was amended to adopt language from 75 Federal Register 61606 and 61607, which amended 40 CFR 52.21, *Prevention of Significant Deterioration (PSD)* to incorporate Greenhouse Gases (GHGs) regulatory provisions. Beginning July 1, 2011, new sources emitting GHGs in excess of 100,000 tons/yr on a carbon dioxide equivalent (CO_2e) basis and also exceeding 100/250 tons/yr on a mass basis are subject to PSD permitting requirements for their GHG emissions. For those affected facilities, Best Available Control Technology (BACT) is to be determined for GHG emissions.

The facility is a new major stationary source for at least one regulated pollutant (GHGs) and subject to the requirements of 40 CFR 52.21 as adopted under K.A.R. 28-19-350. As a result, the potential emissions of CO_2e, NO_X, CO, SO_2, VOC, PM, PM_{10}, particulate matter less than 2.5 microns ($PM_{2.5}$), and sulfuric acid mist (H_2SO_4) were evaluated. The PTE of NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, and CO_2e were determined to be above the PSD significance thresholds. Pursuant to 40 CFR 52.21, since NO_X and VOC emissions for the proposed facility are significant, emissions of ozone (O_3) precursors are deemed significant. NO_X and VOC are precursors and therefore surrogates for O_3, and NO_X and VOC controls will be deemed controls for O_3.

Pursuant to PSD requirements, an air dispersion modeling impact analysis, an additional impact analysis, and a BACT determination were conducted as a part of the construction permit application process. An air dispersion modeling impact analysis was performed for nitrogen dioxide (NO_2), CO, PM_{10}, and $PM_{2.5}$.

BACT-based emission limitations were determined for all emission units and activities which have the potential to emit NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$ and CO_2e.

II. Significant Applicable Air Pollution Control Regulations

A. K.A.R. 28-19-11, Exceptions due to breakdown or scheduled maintenance – as applied to state regulations K.A.R. 28-19-30 through 32 and K.A.R. 28-19-650.

B. K.A.R. 28-19-30 through 32, Indirect heating equipment emissions.

C. K.A.R. 28-19-275, Special provisions; acid rain deposition.

D. K.A.R. 28-19-300, Construction permits and approvals; applicability.

E. K.A.R. 28-19-350, which adopts by reference 40 CFR 52.21, Prevention of significant deterioration of air quality.

F. K.A.R. 28-19-500, Operating permit; applicability.

G. K.A.R. 28-19-650, Emissions opacity limits.

H. K.A.R. 28-19-720, which adopts by reference 40 CFR Part 60, New Source Performance Standards.

I. K.A.R. 28-19-750, which adopts by reference 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants.

J. 40 CFR Part 60, Subpart A, General Provisions.

K. 40 CFR Part 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

L. 40 CFR Part 60, Subpart JJJJ, Standards of Performance for Stationary Spark Ignition Internal Combustion Engines.

M. 40 CFR Part 63, Subpart A, General Provisions.

N. 40 CFR Part 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

O. 40 CFR Part 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.

P. 40 CFR Part 72, Subpart A, Acid Rain Program General Provisions.

III. Air Emission Unit Technical Specifications

The following equipment or equivalent is approved:

A. Ten new spark ignition RICE EGUs (Wartsila model 20V34SG), used to generate electricity. The generating capacity of each EGU will be 9.34 megawatts (approximately 12,526 BHP). Each EGU shall be equipped with a selective catalytic reduction (SCR) system and an oxidation catalyst, and shall burn only pipeline quality natural gas for fuel. The EGUs are subject to the requirements of 40 CFR Part 60 Subpart JJJJ and 40 CFR Part 63 Subpart ZZZZ. The EGUs are subject to the requirements of K.A.R. 28-19-350, Prevention of Significant Deterioration (PSD) of Air Quality, which adopts by reference 40 CFR 52.21. The EGUs are subject to BACT for NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, and CO_2e.

B. One compression ignition emergency fire pump engine (engine make and model to be determined), rated at 150 HP, which shall burn only ultra-low sulfur diesel (ULSD, 15 ppm sulfur or less). This unit is subject to the requirements of 40 CFR Part 60 Subpart IIII and 40 CFR Part 63 Subpart ZZZZ. This fire pump is subject to the requirements of K.A.R. 28-19-350, Prevention of Significant Deterioration (PSD) of Air Quality, which adopts by reference 40 CFR 52.21. This unit is subject to BACT for NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, and CO_2e.

C. One compression ignition emergency diesel engine (engine make and model to be determined), rated at 324 HP, which shall burn only ultra-low sulfur diesel (ULSD, 15 ppm sulfur or less). This unit is subject to the requirements of 40 CFR Part 60 Subpart IIII and 40 CFR Part 63 Subpart ZZZZ. This diesel engine is subject to the requirements of K.A.R. 28-19-350, Prevention of Significant Deterioration (PSD) of Air Quality, which adopts by reference 40 CFR 52.21. This unit is subject to BACT for NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, and CO_2e.

D. One indirect fuel-gas heater, rated at 3 mmBtu/hr heat input, which shall only burn natural gas, for the purpose of heating the natural gas fuel prior to combustion in the Wartsila 4SLB RICE. This unit is subject to the requirements of 40 CFR Part 60 Subpart DDDDD. This heater is subject to the requirements of K.A.R. 28-19-350, Prevention of Significant Deterioration (PSD) of Air Quality, which adopts by reference 40 CFR 52.21. This heater is subject to BACT for NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, and CO_2e.

E. A maximum of four circuit breakers that are electric grid control devices and will contain small amounts of the gaseous dielectric sulfur hexafluoride (SF_6). These devices are subject to the requirements of K.A.R. 28-19-350, Prevention of Significant Deterioration (PSD) of Air Quality, which adopts by reference 40 CFR 52.21. These devices are subject to BACT for CO_2e.

F. One 309,000 diesel fuel storage tank. This tank is subject to the requirements of K.A.R. 28-19-350, Prevention of Significant Deterioration (PSD) of Air Quality, which adopts by reference 40 CFR 52.21. This tank is subject to BACT for VOC.

IV. Air Emission Estimates from the Proposed Activity

The following table contains the PTE for air pollutants to be emitted from the proposed Project:

Table 1. Estimated Emissions	
Pollutant	**Potential-to-emit (PTE)[1] (tons per year)**
NO_X [2]	141.57
CO	169.78
SO_2	2.09
VOC	128.69
PM	63.14
PM_{10} and $PM_{2.5}$	100.59
H_2SO_4	0.32
Total HAPs	50.53
Individual HAPs[3]	
- Acetaldehyde	15.56
- Acrolein	14.10
- Formaldehyde	9.72
Carbon Dioxide Equivalent (CO_2e) Greenhouse Gases (GHG)[4]:	409,409.07
-Carbon Dioxide (CO_2)	408,946.25
-Methane (CH_4)	186.90
-Nitrous Oxide (N_2O)	261.97
-Sulfur Hexafluoride (SF_6)	13.95

[1] Potential-to-emit (PTE) means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable.

[2] NO_X and VOC emissions for the Project exceed the 40 tons significance threshold. Therefore, pursuant to 40 CFR 52.21, the Project is also significant for O_3. Since NO_X and VOCs are surrogates for ozone (O_3), BACT for NO_X and VOC will be considered BACT for O_3.

[3] Only the three individual HAPs with the largest PTE have been listed, which account for 95% of total HAPs. For detailed HAPs PTE estimates, which include all HAPs, refer to the Permit Application submitted July 10, 2012, Appendix C.

[4] Greenhouse gas emissions are converted to CO_2-based equivalence.

V. State Regulatory Requirements

A. K.A.R. 28-19-30 through 32

1. K.A.R. 28-19-31(a) limits filterable particulate matter emissions from the fuel-gas heater to 0.6 lb/MMBtu, except as provided in 28-19-11.

2. K.A.R. 28-19-31(b) limits visible contaminant emissions from the fuel-gas heater to less than 20 percent opacity, except as provided in K.A.R. 28-19-11.

B. K.A.R 28-19-650(a)(3)

Opacity of any visible emissions from any new source is limited to less than 20 percent opacity, except as provided in K.A.R. 28-19-11.

C. Notification

Notify the Northwest District Office Air Program Field Staff at the Hays Office, 2301 East 13th Street, (785) 625-5663, within 30 days after construction is complete so that an evaluation may be conducted.

VI. K.A.R. 28-19-350 Prevention of Significant Deterioration

A. BACT Emission Limitations

1. The emission of pollutants from each EGU shall be no greater than the specified limitations listed below. 40 CFR Part 60 Subpart JJJJ requirements are included in a separate section of the permit as applicable. A violation of a BACT limitation is not necessarily a violation of an NSPS limitation. NSPS limitations are not applicable during startup, shutdown, or malfunction. For the purpose of demonstrating ongoing compliance with BACT-based emission limitations, startup ends 30 minutes after a start sequence is initiated.

   a. The emission of NO_X shall not exceed 1.45 lb/hour at all times except during startup (1-hour averaging period). This limitation is less than the NSPS limitation of 1.0 g/hp-hour (approximately 27.6 lb/hour at 100% load), and the NSPS limitation is therefore subsumed in the BACT emission limitation.

   b. The emission of CO shall not exceed 2.67 lb/hour at all times except during startup (1-hour averaging period). This limitation is less than the NSPS limitation of 2.0 g/hp-hour (approximately 55.2 lb/hour at 100% load), and the NSPS limitation is therefore subsumed in the BACT emission limitation.

c. The emission of VOC shall not exceed 2.67 lb/hour at all times except during startup (1-hour averaging period). This limitation is less than the NSPS limitation of 0.7 g/hp-hour (approximately 19.3 lb/hour at 100% load), and the NSPS limitation is therefore subsumed in the BACT emission limitation.

d. The emission of PM[5] shall not exceed 1.44 lb/hour at all times, including startup (30-day averaging period).

e. The emission of PM_{10}[6] and $PM_{2.5}$[7] shall not exceed 2.22 lb/hour at all times except during startup (24-hour averaging period).

f. The emission of CO_2e shall not exceed 9330[8] lb/hour at all times except during startup (annual averaging period).

g. The 12-month rolling average CO_2 emissions from the EGUs are limited to no more than 1.08 lb/kWh[9]; the total average EGU emissions for each month is determined as follows:

$$ER = x * k * y \div z$$

Where:

ER= emission rate of carbon dioxide from the EGUs, lb/kW-hr;
k = 3.667 lb carbon dioxide emitted per pound carbon in the fuel;
x = lb carbon per cubic foot of natural gas, based on a monthly average fuel analysis by the pipeline supplier;
y = total monthly cubic feet of natural gas burned in the EGUs; and
z = total monthly gross kilowatt hours generated by the EGUs.

h. The emission of NO_X shall not exceed 11.97 lb/hour during startup (1-hour averaging period).

i. The emission of CO shall not exceed 9.72 lb/hour during startup (1-hour averaging period).

j. The emission of VOCs shall not exceed 4.21 lb/hour during startup (3-hour averaging period).

k. The emission of PM_{10} and $PM_{2.5}$ shall not exceed 2.65 lb/hour during startup (24-hour averaging period).

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[5] The term "PM" as used in this permit means that particulate matter (existing as a solid) emitted by a source that can be quantified by analysis under US EPA approved Reference Method 5 as set forth in Appendix A of 40 CFR Part 60.

[6] The term "PM_{10}" as used in this permit means that particulate matter (existing as solid, liquid, and gaseous form) emitted by a source that can be quantified by analysis either by EPA-approved Reference Methods 5 and 202 or by Methods 201A and 202 (with appropriate cyclone-sizing devices appropriate for quantification of PM_{10}), or other such EPA approved test methods.

[7] The term "$PM_{2.5}$" as used in this permit means that particulate matter (existing as solid, liquid, and gaseous form) emitted by a source that can be quantified by analysis either by EPA approved Reference Methods 5 and 202 or by Methods 201A and 202 (with appropriate cyclone sizing devices appropriate for the quantification of $PM_{2.5}$) or other such EPA approved test methods.

[8] The CO_2 emitted is 9320 lb/hour; the remaining 10 lb/hour is the GHG equivalent attributed to methane and nitrous oxides.

[9] Fuel carbon dioxide is not included in this calculation. Startup fuel and energy produced during startups will not be included in this calculation. Fuel gas heater natural gas consumed is not included in the calculation.

l. The emission of CO_2e shall not exceed 9,100 lb/hour during startup (annual averaging period).

2. The BACT emission of pollutants from the emergency diesel generator shall be no greater than limitations specified below, excluding periods of startup, shutdown, and malfunction.

   a. The emission of NO_X shall not exceed 2.98 g/hp-hr.

   b. The emission of CO shall not exceed 2.61 g/hp-hr.

   c. The emission of VOC shall not exceed 3.00 g/hp-hr.

   d. The emissions of PM, PM_{10}, and $PM_{2.5}$ shall not exceed 0.15 g/hp-hr.

   e. BACT for CO_2e shall be use of the most efficient engine that meets the facility's needs.

3. The BACT emission of pollutants from the emergency fire pump shall be no greater than limitations specified below, excluding periods of startup, shutdown, and malfunction.

   a. The emission of NO_X shall not exceed 3.00 g/hp-hr.

   b. The emission of CO shall not exceed 3.70 g/hp-hr.

   c. The emission of VOC shall not exceed 3.00 g/hp-hr.

   d. The emissions of PM, PM_{10}, and $PM_{2.5}$ shall not exceed 2.20E-1 g/hp-hr.

   e. BACT for CO_2e shall be use of the most efficient engine that meets the facility's needs.

4. The BACT emissions of pollutants from the indirect fuel-gas heater shall be no greater than limitations specified below, excluding periods of startup, shutdown, and malfunction.

   a. The emission of NO_X shall not exceed 0.29 lb/hour.

   b. The emission of CO shall not exceed 0.25 lb/hour.

   c. The emission of VOC shall not exceed 0.016 lb/hour.

   d. The emissions of PM, PM_{10}, and $PM_{2.5}$ shall not exceed 0.022 lb/hour.

   e. BACT for CO_2e shall be use of clean fuels, good combustion practices in accordance with the manufacturer's recommendations, proper maintenance, and tuning of the heater.

5. The BACT emissions of pollutants from the fuel oil storage tank shall be use of a submerged fill pipe.

B. Operating Limitations

1. The owner or operator shall maintain the NO_X reactor catalyst for each EGU so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10% from the pressure drop that was measured during the initial performance test.

2. The owner or operator shall maintain the exhaust temperature of the EGU so that the oxidation catalyst inlet temperature is between 450°F and 1350°F.

3. In accordance with the manufacturer's recommendations, the owner or operator shall install, calibrate, operate, and maintain a flow meter to measure and record the ammonia injection rate for the SCR control system for each EGU. The owner or operator shall document the range of ammonia flow rates required to meet the NO_X emission limitation in Section VI. A. BACT Emission Limitation 1a.

4. Neither the emergency diesel generator nor the emergency fire pump shall be operated for more than 100 hours per year for testing and maintenance. Emergency use is not limited.

5. Only pipeline quality natural gas[10] shall be burned in the EGUs and the indirect fuel-gas heater.

6. Only ULSD (less than 15 ppm sulfur) shall be burned in the emergency fire pump and the emergency diesel generator.

7. The owner or operator shall install only state-of-the art enclosed pressure SF_6 circuit breakers with a guaranteed loss rate of 0.5% by weight or less by year.

8. The owner or operator shall install and operate a density monitor alarm system for the SF_6 circuit breakers.

9. The owner or operator shall develop and implement a written leak detection and repair (LDAR) program for the SF_6 circuit breakers.

10. The owner or operator shall operate and maintain all emission units, air pollution control equipment, and monitoring equipment in accordance with the manufacturer's recommendations, in a manner consistent with good combustion practices for minimizing emissions at all times, including periods of startup, shutdown, and malfunction, and in accordance with the manufacturer's recommendations.

11. Stack parameters for all equipment listed under Section III, Air Emissions Unit Technical Specifications, including but not limited to stack heights, stack diameters, exhaust temperatures, emission rates, and exit velocities, shall be consistent with data provided for the dispersion modeling analysis. Actual operational conditions shall be consistent with data provided for the dispersion modeling analysis.

C. Compliance

1. Compliance with A. BACT Emission Limitations 1 is established by performance testing as identified in D. Performance Testing, except for Limitation 1g.

2. Compliance with A. BACT Emission Limitation 1g is established by monitoring as identified in E. Monitoring Requirements 2.

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[10] Pipeline quality natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions and which is provided by a supplier through a pipeline. Pipeline quality natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 Btu per standard cubic foot. The H_2S content shall be less than 4 ppm per 100 cubic feet of gas.

3. Compliance with A. BACT Emission Limitations 2a through c is established by demonstrating compliance with 40 CFR Part 60 Subpart IIII.

4. Compliance with A. BACT Emission Limitations 3a through c is established by demonstrating compliance with 40 CFR Part 60 Subpart IIII.

5. Compliance with A. BACT Emission Limitations 2d, 2e, 3d, 3e, 4, and 5 is established by the BACT analysis and emissions calculations submitted with the permit application.

D. Performance Testing Requirements

1. When conducting the compliance performance tests required by this permit, the reference test methods and procedures identified in K.A.R. 28-19-212 and/or EPA-approved test methods shall be used to demonstrate compliance with the limitations and conditions set forth in this permit.

2. For each EGU, an initial performance test shall be conducted within 180 days after startup to demonstrate compliance with each BACT emission limitation as specified in C. Compliance, except CO_2e BACT limitations. Each engine shall be tested to demonstrate compliance with each limitation, except the CO_2e BACT limitation, no less frequently than every five years. This testing schedule shall not supersede performance test requirements for any applicable federal rules.

3. For each EGU, an initial performance test shall be conducted to demonstrate compliance with the CO_2e emission limitation within 180 days after startup. The performance test shall consist of testing for CO_2 emissions only, which account for over 99% of total CO_2e emissions. Emissions from each engine measured during the performance test shall be compared to a limit of 9090 lb/hour CO_2 during startup, and 9320 lb/hour CO_2 at all times except startup. The owner or operator will monitor the overall performance of each EGU in accordance with good utility practice. Additionally, the owner or operator will perform one follow-up performance evaluation during each semi-annual (calendar) reporting period[11]; such evaluation should occur when the EGU is being operated above 90% load and in a steady-state condition (off automatic governor control); the evaluation should take place when the ambient conditions, fuel quality, and maintenance conditions that most closely approximate those conditions identified in the unit design specifications.

4. Except for performance tests conducted to demonstrate compliance with startup emission limitations, performance tests shall be conducted at no less than 90% of maximum load conditions.

5. A performance test protocol identifying proposed test methods and the proposed test schedule shall be submitted 60 days prior to testing and the protocol is subject to KDHE approval.

[11] An EGU operating less than 100 hours within a semi-annual reporting period will not be obligated to the performance evaluation.

E. Monitoring Requirements

1. For each EGU, a continuous monitoring parameter system (CPMS) shall be installed, and monitoring parameters shall be established during the initial performance test. The CPMS shall take a minimum of four readings per hour. The following parameters shall be monitored:

   a. SCR ammonia injection rate (range to be determined during the performance test);

   b. Oxidation catalyst inlet temperature (maintain the temperature of the EGU exhaust so that the catalyst inlet temperature is between 450°F and 1350°F); and

   c. Catalyst bed pressure drop (maintain the catalyst pressure drop so that the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10% from pressure drop across the catalyst that was measured at initial performance test).

2. The owner or operator shall monitor the carbon content of the natural gas burned in the EGUs, based on a monthly average fuel analysis by the natural gas pipeline supplier; the total monthly cubic feet of natural gas burned in the EGUs as measured by a station grade fuel flow meter; and the gross power output as measured by a station grade watt-hour meter. This data shall be used to calculate compliance with A. BACT Emission Limitation 1g on a monthly basis.

3. For the circuit breakers, the owner or operator shall monitor SF_6 emissions by measuring the SF_6 lost and using a conversion factor to assess annual SF_6 fugitive emissions in terms of CO_2e.

4. For the circuit breakers, the owner or operator shall implement a density monitor alarm system with a threshold of 10%, that is, the alarm will alert controllers when the circuit breakers lose 10% of the SF_6. In the event of an alarm, the owner or operator will investigate the event and take any necessary corrective action to address any problems.

F. Recordkeeping Requirements

1. The owner or operator shall maintain records of the hours of operation of the emergency diesel generator and the emergency fire pump.

2. The owner or operator shall maintain records of fuel analysis for all emission units demonstrating that only pipeline quality natural gas and ULSD were burned as required by this permit.

3. The owner or operator shall develop and maintain a record of all startup and malfunction activities, including malfunction in the operation of each unit and any malfunction of any air pollution control equipment. The record shall also include all maintenance activities including the nature of all repairs taken to correct malfunction incidents.

4. Records shall be kept documenting each performance test conducted. In addition, records shall be kept of CPMS monitoring parameters compared to the ranges required by B. Operating Limitations.

5. The owner or operator shall maintain CPMS records that include the occurrence and duration of any startup, shutdown, or malfunction; performance testing; evaluations; calibrations; checks; adjustments; maintenance; duration of any periods during which a CPMS is inoperative; and corresponding measurement during which parameters established are outside the range established in this permit. Records shall be kept on site and in a form readily available for inspection.

6. The owner or operator shall keep records of all data and compliance calculations required by E. Monitoring Requirement 2.

7. The owner or operator shall keep a copy of the SF_6 circuit breakers LDAR program and documentation regarding observations and/or repairs made in accordance with the LDAR program. If requested, this documentation shall be provided to KDHE.

8. The owner or operator shall keep records of the type and/or specifications of each emission unit installed at the proposed station.

9. The owner or operator shall keep records relating to maintaining good combustion practices for each emission unit in accordance with the manufacturer's recommendation to maintain efficiency of the combustion sources.

10. All records shall be retained for two years from the date of record.

G. Reporting Requirements

1. The owner or operator shall submit semiannual reports detailing compliance with the emission and operating limitations established in this permit; emissions measured or calculated shall be expressed in the same units as the BACT emission limitations. These reports shall be submitted within 30 days following the end of each calendar half-year and shall include:

   a. The company name and address of the facility.

   b. An identification of each emission unit being included in the semiannual report.

   c. Beginning and ending dates of the reporting period.

   d. Excess emissions and CPMS monitor downtime. The owner or operator shall report excess emissions for all periods of unit operation, including startup, shutdown, and malfunction.

   e. A summary of startup, shutdown, malfunction events which occurred during the reporting period.

2. The owner or operator must notify KDHE by telephone, facsimile, or electronic mail transmission within two working days following the discovery of any failure of air pollution control equipment, process equipment, or process to operate in a normal manner which results in an increase in emissions above any allowable emission limitation. In addition, the owner or operator must notify KDHE in writing within ten days of any such failure. The written notification shall include a description of the malfunctioning equipment or abnormal operation, the date of the initial malfunction, the period of time over which emissions were increased due to the failure, the cause of the failure, the estimated resultant emissions in excess of those allowed, and the methods utilized to mitigate emissions and restore normal operation.

3. If significant changes are made, or modeling parameters are not representative of site conditions, the owner or operator shall document compliance with the applicable NAAQS and allowable PSD increment consumption and submit documentation of compliance to KDHE prior to making the change(s). KDHE has final authority in determining what constitutes a significant change. If modeling indicates a potential NAAQS or increment exceedance, then mitigation shall be required.

VII. 40 CFR Part 60 Subpart IIII

A. Emission Limitations

1. Pursuant to 40 CFR 60.4205(b), the owner or operator of the emergency diesel engine shall comply with applicable emission standards in 60.4202 for all pollutants, for the same model year and maximum engine power. The stationary emission manufacturer must certify the emergency diesel engine to the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113.

2. Pursuant to 40 CFR 60.4205(c), the owner or operator of the emergency fire pump engine shall comply with the applicable emission standards in Table 4 of 40 CFR 60 Subpart IIII. The owner or operator shall also meet the requirements of 60.4206. In accordance with Table 4 of 40 CFR 60 Subpart IIII, the emergency fire pump engine NMHC+ NO_X emissions shall not exceed 4.0 g/kW-hr (3.0 g/hp-hr), CO emissions shall not exceed 5.0 g/kW-hr (3.7 g/hp-hr), and PM emissions shall not exceed 0.30 g/kW-hr (0.22 g/hp-hr) over the life of the engine. The engine shall be certified by the manufacturer to meet these emission limits per 40 CFR 60.4202(d).

B. Operating Limitations

1. For the emergency fire pump engine and the emergency diesel engine, the owner or operator shall comply with applicable diesel fuel requirements of 40 CFR 60.4207.

2. For the emergency fire pump engine, the provisions of 40 CFR 60.4211(f) apply. Maintenance checks and readiness testing is limited to 100 hours per year, of which up to 50 hours per year may be for non-emergency situations. There is no time limit on the use of the emergency fire pump in emergency situations.

C. Monitoring Requirements

If the emergency fire pump engine and/or the emergency diesel engine do not meet the standards applicable to non-emergency engines, the owner or operator must install a non-resettable hour meter prior to startup of the engine, as specified in 40 CFR 60.4209.

D. Compliance Requirements

For the emergency fire pump engine and the emergency diesel engine, the owner or operator must install, configure, operate, and maintain the engine and control device according to the manufacturer's emission-related written instructions. The owner or operator must not change emission-related settings in a way that is not permitted by the manufacturer, or thereafter demonstrate compliance as specified at 40 CFR 60.4211(g)(2).

E. Recordkeeping Requirements

For the emergency fire pump engine and the emergency diesel engine, the owner or operator must keep records of the emergency and non-emergency operations of the engine through a non-resettable hour meter if it does NOT meet the standards applicable to the non-emergency engines in the applicable model year. The times of operation and the reasons for operation must be recorded, as specified in 40 CFR 60.4214(b).

F. Reporting Requirements

If the emergency diesel engine is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in 60.4211(f)(2)(ii) and (iii) or that operates for the purposes specified in 60.4211(f)(i), you must submit an annual report according to the requirements in 60.4214(d).

G. Applicability of Federal Rule General Provisions

For the emergency fire pump engine and the emergency diesel engine, 40 CFR 60.4218 and Table 8 identify the Subpart A requirements that are applicable.

H. Additional Provisions

The owner or operator shall comply with all requirements of 40 CFR Part 60 Subpart IIII. These requirements are summarized in this permit. If a conflict exists between the federal rule and the permit, the requirements of the federal rule shall take precedence.

VIII. 40 CFR Part 60 Subpart JJJJ

A. Emission Limitations

1. For each EGU, the owner or operator shall comply with the requirements of 40 CFR 60.4233(e) and 60.4234. These regulations require the owner or operator to meet the applicable emission limitations in Table 1 of 40 CFR 60 Subpart JJJJ for the EGUs over their entire lives. Table 1 of 40 CFR 60 Subpart JJJJ provides the following emission limitations for the EGUs:

   a. Emission of NO_X is limited to no more than 1.0 g/hp-hour or 82 ppmvd at 15% O_2.

   b. Emission of CO is limited to no more than 2.0 g/hp-hour or 270 ppmvd at 15% O_2. Owners or operators of engines located at major sources that are meeting the requirements of 40 CFR Part 63, Subpart ZZZZ Table 2a do not have to comply with this standard as specified in Table 1.

   c. Emission of VOC is limited to no more than 0.7 g/hp-hour or 60 ppmvd at 15% O_2.

B. Compliance Requirements

1. For each EGU that is not certified, performance testing shall be conducted in accordance with 40 CFR 60.8(a) within 60 days of reaching maximum production rate, but not later than 180 days after initial startup.

2. For each EGU that is not certified, and as required by 40 CFR 60.4243(b)(2)(ii), the owner or operator must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner

consistent with good air pollution control practice for minimizing emissions. The owner or operator shall comply with the requirements of 40 CFR 60.4243(b)(2)(ii) to conduct an initial performance test and conduct subsequent performance testing every 8760 hours or three years, whichever comes first, thereafter to demonstrate compliance.

C. Performance Testing Requirements

For each EGU that is not certified, each performance test must be conducted following the requirements of §60.4244 and according to the requirements in 40 CFR 60.8 and under the conditions specified in Table 2.

D. Notification, Reporting, and Recordkeeping Requirements

1. For each EGU, the owner or operator shall comply with the recordkeeping requirements of 40 CFR 60.4245(a).

2. For each EGU, the owner or operator shall comply with the notification requirements of 40 CFR 60.4245(c).

3. For each EGU, the owner or operator shall comply with the reporting requirement outlined in 40 CFR 60.4245(d), which requires the owner or operator to submit a copy of each performance test within 60 days after the test has been completed.

E. Applicability of Federal Rule General Provisions

For the EGUs, the owner or operator is required to follow 40 CFR Part 60 Subpart A General Provisions requirements outlined in 40 CFR 60.4246 and in Table 3, which excludes the monitoring requirements of 40 CFR 60.13 and the general control device requirements in 40 CFR 60.18.

F. Additional Provisions

The owner or operator shall comply with all requirements of 40 CFR Part 60 Subpart JJJJ. These requirements are summarized in this permit. If a conflict exists between the federal rule and the permit, the requirements of the federal rule shall take precedence.

IX. 40 CFR Part 63 Subpart ZZZZ

A. Emission Limitations

For each EGU, the owner or operator shall comply with the requirements 40 CFR 63.6600(b) and Table 2a. Each EGU emission control system is required to reduce CO emissions by 93 percent or more; or limit the concentration of formaldehyde in the exhaust to 14 ppmvd or less at 15 percent O_2.

B. Operating Limitations

For each EGU, the owner or operator shall comply with the requirements 40 CFR 63.6600(b) and Table 2b.

C. Performance Testing Requirements

1. For each EGU, the owner or operator shall comply with 40 CFR 63.6610(a) and Table 4. The owner or operator must conduct the initial performance test within 180 days after the compliance date that is specified in 40 CFR 63.6595 and according to the provisions of 40 CFR 63.7(a)(2). Requirements are outlined in Table 4, Item 1a for compliance with

the requirement to reduce CO emissions, and are outlined in Table 4, Item 3a for compliance with the requirement to limit the concentration of formaldehyde in the exhaust.

2. For each EGU, the owner or operator shall comply with the requirements of 40 CFR 63.6615 to conduct subsequent performance tests as specified in Table 3. Requirements are outlined in Table 3, Item 1 for compliance with the requirement to reduce CO emissions, and are outlined in Table 3, Item 3 for compliance with the requirement to limit the concentration of formaldehyde in the exhaust.

3. For each EGU, the owner or operator shall follow the performance test and other procedures and requirements of 40 CFR 63.6620.

D. Monitoring, Installation, Collection, Operation, and Maintenance Requirements

1. For each EGU, the owner or operator shall comply with the requirements of 40 CFR 63.6625(b) to install a continuous parameter monitoring system (CPMS) as specified in Table 5. The owner or operator must install, operate, and maintain each CPMS according to the requirements of 40 CFR 63.6625(b).

2. For each EGU, the owner or operator shall comply with the requirements of 40 CFR 63.6625(h) to minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to conditions other than startup in Table 2a shall apply.

E. Initial Compliance

1. For the EGUs, the owner or operator shall comply with the following requirements of 40 CFR 63.6630 to demonstrate initial compliance with emission limitations and operating limits:

   a. Comply with each emission and operating limitation that applies in Table 5.

   b. Establish each operating limitation in Table 2b that applies.

   c. Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 40 CFR 63.6645.

F. Continuous Compliance

1. For each EGU, the owner or operator must be in compliance with the applicable emission limitations and operating limitations in 40 CFR 63 Subpart ZZZZ at all times as provided in 40 CFR 63.6605.

2. 40 CFR 63.6605(b) requires that the owner or operator must operate and maintain the engines, including their associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to KDHE which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

3. For each EGU, the owner or operator shall comply with the requirements of 40 CFR 63.6635 to monitor and collect data to demonstrate continuous compliance.

4. For each EGU, except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, the owner or operator must monitor continuously at all times that the EGU is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

5. For each EGU, the owner or operator may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. The owner or operator must use all the valid data collected during all other periods.

6. For each EGU, the owner or operator shall comply with the following requirements of 40 CFR 63.6640 to demonstrate continuous compliance with emission limitations and operating limitations:

   a. According to 40 CFR 63.6640(a), the owner or operator must demonstrate continuous compliance with each emission limitation and operation limitation in Tables 2a and 2b according to the methods specified in Table 6 of 40 CFR 63 Subpart ZZZZ.

   b. According to 40 CFR 63.6640(b), the owner or operator must report each instance in which the EGU does not meet each emission limitation or operating limitation in Tables 2a and 2b or 40 CFR 63 Subpart ZZZZ. These instances are deviations from the emissions and operating limitations in 40 CFR 63 Subpart ZZZZ. These deviations must be reported according to the requirements in 40 CFR 64.6650. If the catalyst is changed, the owner or operator must reestablish the values of the operating parameters measured during the initial performance test. The owner or operator must also conduct a performance test to demonstrate compliance with the required emission limitation applicable to the EGU.

   c. According to 40 CFR 63.6640(d), deviations from the emission or operating limitations that occur during the first 200 hours of operation from the initial startup (engine burn-in period) are not violations.

   d. The owner or operator must report each instance in which the applicable requirements in Table 8 to 40 CFR 63 Subpart ZZZZ are not met.

G. Notification Requirements

1. For the emergency diesel generator and the emergency fire pump, 40 CFR 63.6590 requires the facility to meet the requirements of Subpart ZZZZ and Subpart A by following the initial notification requirements of 40 CFR 63.6645(f).

2. For each EGU, the owner or operator shall comply with the notification requirements of §63.6645. These include but are not limited to the following:

   a. According to 40 CFR 63.6645(a), submit all of the notifications required at 40 CFR 63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) by the dates specified.

   b. According to 40 CFR 63.6645(c), submit an Initial Notification not later than 120 days after the facility becomes subject to 40 CFR Part 63 Subpart ZZZZ.

c. According to 40 CFR 63.6645(g), submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in 40 CFR 63.7(b)(1).

d. According to 40 CFR 63.6645(h), submit a Notification of Compliance Status according to 40 CFR 63.9(h)(2)(ii). For each initial compliance demonstration required in Table 5 that includes a performance test conducted according to the requirements in Table 3, the owner or operator shall submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to 40 CFR 63.10(d)(2).

H. Reporting Requirements

For each EGU, the owner or operator shall comply with the applicable reporting requirements of 40 CFR 63.6650 and in Table 7 of 40 CFR 63 Subpart ZZZZ.

I. Recordkeeping Requirements

1. For each EGU, the owner or operator shall comply with the applicable recordkeeping requirements of 40 CFR 63.6655 and in Table 6 of 40 CFR 63 Subpart ZZZZ.

2. For each EGU, the owner or operator must keep records in the form and for the length of time specified in 40 CFR 63.6660.

J. Applicability of Federal Rule General Provisions

For each EGU, the owner or operator is required to follow the applicable requirements of 40 CFR Part 63 Subpart A General Provisions as specified in 40 CFR 63.6665 and outlined in Table 8 of 40 CFR 63 Subpart ZZZZ.

K. Additional Provisions

The facility shall comply with all requirements of 40 CFR Part 63 Subpart ZZZZ. Requirements are summarized in this permit. If a conflict exists between the federal rule and the permit, requirements of the federal rule shall take precedence.

X. 40 CFR Part 63 Subpart DDDDD

A. Work Practice Standards

1. The owner or operator shall meet the requirements of 63.7500 at all times the fuel-gas heater is operating.

2. The owner or operator shall meet each work practice standard in Table 3 that applies to the fuel-gas heater as required by 63.7500(a)(1). Table 3 requires the owner or operator to conduct a tune-up of the fuel-gas heater every 5 years as specified in 63.7540.

3. At all times, the owner or operator must operate and maintain the fuel-gas heater in a manner consistent with safety and good air pollution control practices for minimizing emissions as required by 63.7500(a)(3).

B. Initial Compliance

1. As required by 63.7510(g), the owner or operator of the fuel-gas heater must demonstrate initial compliance with the applicable work practice standards in Table 3 within the applicable 5 year schedule as specified in 63.7540(a) following the initial compliance date specified in 63.7495(a). Thereafter, the owner or operator shall complete the 5-year tune-up as specified in 63.7540(a) and 63.7515(d).

2. As required by 63.7530(d), the owner or operator of the fuel-gas heater must submit a signed statement in the Notification of Compliance Status Report that indicates that a tune-up of the unit was conducted.

3. As required by 63.7530(f), the owner or operator must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 64.7545(e).

C. Continuous Compliance

1. The owner or operator shall demonstrate continuous compliance with requirements of this subpart according to the methods and schedule specified in 63.7540(a).

2. As required by 63.7540(a)(12), the owner or operator must conduct a tune-up of the fuel-gas heater every 5 years as specified in paragraphs 63.7540(a)(10)(i) through (vi) to demonstrate continuous compliance.

3. The owner or operator must report each instance in which the requirements in Table 3 for the fuel-gas heater were not met. These instances are deviations and must be reported according to the requirements in 63.7550.

D. Notification, Reports, and Records

1. The owner or operator shall submit all of the notifications in 63.7545, and 63.9(b) through (h) if applicable by the dates specified.

2. The owner or operator shall submit reports specified in 63.7550 that apply and by the dates specified.

3. The owner or operator shall keep records as specified in 63.7555, and in the form and for the length of time specified in 63.7560.

E. Applicability of Federal Rule General Provisions

For the fuel-gas heater, the owner or operator is required to follow the applicable requirements of 40 CFR Part 63 Subpart A General Provisions as specified in 40 CFR 63.7565 and outlined in Table 10 of 40 CFR 63 Subpart DDDDD.

F. Additional Provisions

The owner or operator shall comply with all requirements of 40 CFR Part 63 Subpart DDDDD. These requirements are summarized in this permit. If a conflict exists between the federal rule and the permit, the requirements of the federal rule shall take precedence.

XI. 40 CFR Part 72 Subpart A

The EGUs are considered to be new utility units under 40 CFR 72.6. 40 CFR 72.7(b) states that any new utility unit that has not previously lost an exemption under 40 CFR 72.7(f)(4) and that meets provisions of 40 CFR 72.7(a) shall be exempt from the Acid Rain Program, except for the provisions of 40 CFR 72.2 through 72.6, and 72.10 through 72.13. This exemption shall be effective on January 1 of the first full calendar year for which the unit meets these requirements. By December 31 of the first year for which the unit is to be exempt, a statement signed by the designated representative or certifying official shall be submitted to the KDHE Bureau of Air. The statement shall identify the unit, state the nameplate capacity of each generator served by the unit and the fuels currently burned or expected to be burned by the unit and their sulfur content by weight, and state that the owners and operators of the unit will comply with 40 CFR 72.7(f).

XII. Title V

K.A.R. 28-19-500 requires the owner or operator to obtain a Title V (Class I) Operating Permit for the facility. A complete application shall be submitted within one year of the initial startup of this facility as specified in K.A.R. 28-19-510.

XIII. Permit General Provisions

A. This document will become void if construction or modification has not commenced within 18 months of the effective date, or if the construction or modification is interrupted for a period of 18 months or longer. [K.A.R. 28-19-301(c)].

B. A construction permit or approval must be issued by KDHE prior to commencing any construction or modification of equipment or processes which results in an increase of potential-to-emit equal to or greater than the thresholds specified at K.A.R. 28-19-300(a) and (b).

C. Upon presentation of credentials and other documents as may be required by law, representatives of KDHE (including authorized contractors of KDHE) shall be allowed to:

1. enter upon the permittee's premises where a regulated facility or activity is located or conducted or where records shall be kept under conditions of this document;
2. have access to and copy, at reasonable times, any records that shall be kept under conditions of this document;
3. inspect at reasonable times, any facilities, equipment (including monitoring and control equipment) practices or operations regulated or required under this document; and
4. sample or monitor, at reasonable times, for the purposes of assuring compliance with this document or as otherwise authorized by the Secretary of KDHE, any substances or parameters at any location.

D. The emission unit or stationary source, which is the subject of this document, will be operated in compliance with all applicable requirements of the Kansas Air Quality Act and the federal Clean Air Act.

E. This document is subject to periodic review and amendment as deemed necessary to fulfill the intent and purpose of the Kansas Air Quality Statutes and Regulations and rules promulgated in accordance therewith.

F. This document does not relieve the permittee of the obligation to obtain any approvals, permits, licenses, or documents of sanction, which may be required by other federal, state or local government agencies.

Permit Writer

Mindy Bowman

Mindy Bowman, P.E.
Professional Environmental Engineer
Air Permitting Section

1/24/14

Date Signed

MGB:saw
c: Larissa Parker, NWDO
C-10593

EXHIBIT 3

to Sierra Club Comments

Report on the

Prevention of Significant Deterioration – Air Construction Permit Application

Lacey Randall Station – TradeWind Energy, Inc.
Source ID 1930036

Project No. 72125

Updated December 2013

Prevention of Significant Deterioration – Air Construction Permit Application

prepared for

Lacey Randall Station – TradeWind Energy, Inc.
Source ID 1930036
Colby, Kansas

Updated December 2013

Project No. 72125

prepared by

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Kansas City, Missouri

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1.0 EXECUTIVE SUMMARY

Pursuant to the requirements specified in the Kansas Administrative Regulations (K.A.R) 28-19-350, TradeWind Energy Inc. (TradeWind) submits this Prevention of Significant Deterioration (PSD) construction permit application for the installation of up to ten reciprocating internal combustion engines (RICE) plus auxiliary equipment at the Lacey Randall Station (hereinafter referred to as the Project) to be located in Thomas County, Kansas approximately 3 miles northeast of Colby, Kansas. The Project will have a total nominal power output of approximately 94 megawatts (MW) and the RICE electric generating units (EGUs) will be fired solely by natural gas.

As required by the above-referenced rules, this permit application contains the following analyses/assessments regarding the emission of regulated pollutants associated with the construction and operation of the Project:

- Evaluation of ambient air quality in the area for each regulated pollutant for which the Project will cause a significant increase in net emissions
- Demonstration by air dispersion analysis that emissions from the Project will not cause or contribute to any exceedance of a National Ambient Air Quality Standard (NAAQS)
- Demonstration by air dispersion analysis that emissions from the Project will not exceed the remaining available PSD Class II increment consumption allowances
- Assessment of any adverse impacts on soils, vegetation, visibility, or growth in the area
- A Best Available Control Technology (BACT) analysis for each regulated pollutant for which the potential-to-emit (PTE) for the Project will result in a significant increase in net emissions

PTE from the Project are shown in Table 1-1. Start-up emissions for the engines are also included in Table 1-1. A full description of equipment associated with the Project is provided in Part 2 of the application.

Table 1-1. Project Potential Emissions and PSD Significance Levels

Pollutant[A]	Preliminary Estimated Potential Emissions (Tons per Year [TPY])[B]	PSD Significance Levels (TPY)
NO_x	**141.57**	40
SO_2	2.09	40
CO	**169.78**	100
PM/PM_{10}[C]	**100.59**	25/15
$PM_{2.5}$[C]	**100.59**	10
VOC	**128.69**	40
Lead	6.44E-06	0.6
H_2SO_4 Mist	0.32	7
CO_2e	**409,409**	75,000

[A] NO_x = nitrogen oxides; CO = carbon monoxide; SO_2 = sulfur dioxide; VOC = volatile organic compounds; PM= total particulate matter; PM_{10} = particulate matter less than 10 microns in diameter; $PM_{2.5}$ = particulate matter less than 2.5 microns in diameter; CO_2e = carbon dioxide equivalent (greenhouse gases); H_2SO_4 Mist = sulfuric acid mist
[B] Numbers in **bold** indicate the PSD significance level is exceeded
[C] Filterable plus condensable

1.1 HAP Emissions

The Project will be a major source of hazardous air pollutants (HAPs) (greater than 25 tons per year of total HAPs and greater than 10 tons per year of any single HAP).[1] Therefore sections of 40 CFR Part 63-National Emission Standards for Hazardous Air Pollutants (NESHAP) will apply to the Project.

1.2 Project NAAQS Impact Analysis

The existing air quality in the Thomas County area is designated as attainment or unclassifiable with regard to the NAAQS for all criteria pollutants. A Project air dispersion modeling analysis was performed for the pollutants subject to PSD review to assess potential impacts on the NAAQS. The modeling was performed in accordance with relevant Kansas Department of Health and Environment (KDHE) and U.S. Environmental Protection Agency (EPA) modeling guidance. The air dispersion modeling protocol and Ozone Limiting Method (OLM) modeling protocol were submitted to both KDHE and EPA Region 7 for their review in April 2013.

The modeling analysis results (included in Part 6 of this application) demonstrate that the Project will not cause or contribute to a violation of any NAAQS. Further, the PSD Class II increment analysis demonstrates that Project impacts are less than the PSD Class II increments established for the area.

[1] All sources of HAPs that are not major sources are categorized as "area" sources.

Recent Federal Land Manager (FLM) guidance advises that a proposed major source, in the course of a PSD application, must perform an assessment of air quality impacts at Class I areas if these areas are located within approximately 300 kilometers of the proposed facility. As there are no Class I areas that are within 300 kilometers of the Project, an assessment of air quality impacts at Class I areas was not performed.

1.3 BACT for Reciprocating Internal Combustion Engines

A "top-down" BACT analysis was performed for each of the pollutants in Table 1-1 in which the PTE was above the associated PSD significance level: NO_x, CO, VOC, $PM/PM_{10}/PM_{2.5}$, and CO_2e (greenhouse gases).

Pre-combustion and controlled combustion systems coupled with state-of-the-art pollution control equipment and consistently achievable emission limitations has been selected as BACT for this Project. Emissions of NO_x from the RICE will be limited by lean burn combustion and further reduced and controlled by selective catalytic reduction (SCR) systems. Emissions of CO and VOC will be limited by good combustion practices and further reduced by oxidation catalysts (also referenced as a CO catalyst). Use of clean fuels and good combustion practices will control emissions of $PM/PM_{10}/PM_{2.5}$. Greenhouse gas emissions will be limited by the use of efficient lean-burn engines, and by use of natural gas as a fuel.

Table 1-2 displays the BACT results.

Table 1-2. Summary of BACT Results: RICE

Pollutant	Systems and Controls	BACT Emission Limitation (lb/hr)[A]	Equivalent Emissions[B] (g/bhp-hr)	Averaging Period
NO_x	Selective catalytic reduction (SCR) system	1.45	0.0525	30-day
CO	Good combustion practices, oxidation catalyst	2.67	0.0967	30-day
VOC	Good combustion practices, oxidation catalyst	2.67	0.0967	30-day
$PM/PM_{10}/PM_{2.5}$	Combustion controls and low ash fuels	2.22	NA	3-hr
CO_2e	Use of efficient lean-burn engines, use of natural gas as a fuel	9,329.27	337.81	Annual

[A] Engine emission rate while operating at loads of 50 percent and greater under steady state conditions unless otherwise noted.

[B] Equivalent emissions in gram per brake horsepower hour (g/bhp-hr) for loads of 50% and higher are shown for comparison to the RACT/BACT/LAER Clearinghouse (RBLC) emission rates purposes only. These are not proposed as BACT emission limitations.

[C] Due to the testing methods and sources of PM in the emission exhaust, PM is only expressed in lb/hr and it is not appropriate to determine an equivalent g/bhp-hr. In addition, the RBLC limits are primarily expressed in lb/hr.

1.4 BACT Analysis for Auxiliary Equipment

The auxiliary equipment to be installed at the Project consists of a gas heater (using natural gas for fuel), an emergency diesel fire pump, an emergency diesel generator, and a fuel oil storage tank. A BACT analysis was performed for the pollutants in Table 1-1 that are emitted in total Project quantities above the PSD significance levels for the each of the auxiliary equipment. The following controls and operational practices have been established as applicable BACT requirements for the auxiliary equipment as shown in Table 1-3.

Table 1-3. Summary of BACT Results: Auxiliary Equipment

Pollutant	Emissions Unit	Limiting Systems and Controls	BACT Emission Limitation
NO_x	Gas Heater	Low NO_x Burners and Combustion Control	100 lb/MMcf
	Emergency Diesel-fired Generator	Combustion Control	0.007 gm/hp-hr
	Emergency Fire Pump	Combustion Control	3.00 gm/hp-hr
CO	Gas Heater	Good Combustion Practices	84 lb/MMcf
	Emergency Diesel-fired Generator	Combustion Control	2.61 gm/hp-hr
	Emergency Fire Pump	Combustion Control	3.70 gm/hp-hr
VOC	Gas Heater	Good Combustion Practices	5.5 lb/MMcf
	Emergency Diesel-fired Generator	Combustion Control	0.007 gm/hp-hr
	Emergency Fire Pump	Combustion Control	3.00 gm/hp-hr
	Fuel Oil Storage Tank	Submerged Fill Pipe	0.156 tpy
$PM/PM_{10}/PM_{2.5}$	Gas Heater	Combustion Control	7.6 lb/MMcf
	Emergency Diesel-fired Generator	Combustion Control	3.29E-04 gm/hp-hr
	Emergency Fire Pump	Combustion Controls and Low Ash Fuels	2.20E-01 gm/hp-hr
CO_2e	Gas Heater	Use of Clean Fuels, Maintaining and Tuning the Heater, Recordkeeping	117.00 lb/MMBtu
	Emergency Diesel-fired Generator	Combustion Control	164 lb/MMBtu
	Emergency Fire Pump	Selection of the Most Efficient Engines that Meet the Applicant's Project Needs	164 lb/MMBtu
	Circuit Breakers	Enclosed-Pressure SF_6 Circuit Breakers	<0.5% leakage

[A] g/hp-hr = gram per horsepower hour

1.5 Additional Impacts Analysis

The potential impacts of the Project on visibility, soils, vegetation, and growth are discussed in Section 8.0of this application. As shown by the analysis, the addition of the Project will not have a significant impact on visibility, soils, growth, or vegetation in the surrounding area.

6.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

Per K.A.R. 28-19-350, an owner of a facility applying for a PSD construction permit must perform a Best Available Control Technology (BACT) analysis for each regulated NSR pollutant for which there would be a significant net emissions increase at the stationary source. This requirement applies to any proposed emissions unit at which a net emissions increase in the air pollutant would occur as a result of a physical change or change in the method of operation in the emissions unit.

As can be seen in Table 2-1., the Project is subject to PSD review for CO, NO_x, $PM/PM_{10}/PM_{2\,5}$, VOC, and CO_2e (greenhouse gases).

Therefore, a BACT analysis was performed for each of these pollutants. A summary of the selected control technologies and the associated BACT emission limitations for the RICE is presented in Table 6-1.

Table 6-1. Summary of BACT Results: RICE

Pollutant	Control Technology	BACT Emission Limitation (lb/hr)[A]	Equivalent Emissions[B] (g/bhp-hr)	Averaging Time
NO_x	Selective Catalytic Reduction (SCR) System	1.45	0.053	30-day
CO	Good Combustion Practices, Oxidation Catalyst	2.67	0.10	30-day
VOC	Good Combustion Practices, Oxidation Catalyst	2.67	0.10	30-day
$PM_{10}/PM/PM_{2\,5}$	Combustion Controls and Low Ash Fuels	2.22	NA	3-hr
CO_2e	Use of Efficient Lean-Burn Engines, Use of Natural Gas, and Maintain Efficiency of Engines Through Maintenance Procedures	9,329	338	Annual

[A] Maximum engine emission rate under steady state conditions unless otherwise noted.
[B] Equivalent emissions in gram per brake horsepower hour (g/bhp-hr) for loads of 50% and higher are shown for comparison to the RBLC emission rates purposes only. These are not proposed as BACT emission limitations.
[C] Due to the testing methods and sources of PM in the emission exhaust, PM is only expressed in lb/hr and it is not appropriate to determine an equivalent g/bhp-hr. In addition, the RBLC emission limitations are primarily expressed in lb/hr.

Table 6-2 displays the BACT results for the auxiliary equipment (gas heater, emergency fire pump and emergency diesel-fired generator).

Table 6-2. Summary of BACT Results: Auxiliary Equipment

Pollutant	Emissions Unit	Limiting Systems and Controls	BACT Emission Limitation
NO_x	Gas Heater	Low NO_x Burners and Combustion Control	100 lb/MMcf
	Emergency Diesel-fired Generator	Combustion Control	0.007 gm/hp-hr
	Emergency Fire Pump	Combustion Control	3.00 gm/hp-hr
CO	Gas Heater	Good Combustion Practices	84 lb/MMcf
	Emergency Diesel-fired Generator	Combustion Control	2.61 gm/hp-hr
	Emergency Fire Pump	Combustion Control	3.70 gm/hp-hr
VOC	Gas Heater	Good Combustion Practices	5.5 lb/MMcf
	Emergency Diesel-fired Generator	Combustion Control	0.007 gm/hp-hr
	Emergency Fire Pump	Combustion Control	3.00 gm/hp-hr
	Fuel Oil Storage Tank	Submerged Fill Pipe	0.156 tpy
$PM/PM_{10}/PM_{2\,5}$	Gas Heater	Combustion Control	7.6 lb/MMcf
	Emergency Diesel-fired Generator	Combustion Control	3.29E-04 gm/hp-hr
	Emergency Fire Pump	Combustion Controls and Low Ash Fuels	2.20E-01 gm/hp-hr
CO_2e	Gas Heater	Use of Clean Fuels, Maintaining and Tuning the Heater, Recordkeeping	117.00 lb/MMBtu
	Emergency Diesel-fired Generator	Combustion Control	164 lb/MMBtu
	Emergency Fire Pump	Selection of the Most Efficient Engines that Meet the Applicant's Project Needs	164 lb/MMBtu
	Circuit Breakers	Enclosed-Pressure SF_6 Circuit Breakers	<0.5% leakage

6.1 PSD BACT Process

6.1.1 The "Top-Down" Process

As part of the permitting process, a major stationary source needs to prepare a BACT analysis in conjunction with a PSD permit application. While there is no legal requirement to perform the BACT analysis utilizing a specific criteria or process, EPA has developed guidance that establishes a five-step "top down" BACT process/methodology.[8]

For purposes of this application, TradeWind has conducted its BACT analysis consistent with EPA's top down approach, which consists of the following steps for each pollutant to be emitted from each source:

Step 1 – Identify all potential control technologies
Step 2 – Determine technical feasibility (of potential technologies)
Step 3 – Rank control technologies by control effectiveness
Step 4 – Evaluate most effective controls and document results
Step 5 – Select BACT

Each of these steps is discussed in further detail below.

Step 1 – Identify all potential control technologies. The first step in a "top-down" analysis is to identify, for all applicable emission units, all "available" control options. Available control options are defined as those air pollution control technologies or techniques that have a practical potential for application to the emissions unit and the regulated pollutant under evaluation and have been demonstrated in practice.

Step 2 – Determine technical feasibility (of potential options). In the second step, the technical feasibility of each control option identified in Step 1 is evaluated with respect to the source-specific factors. A demonstration of technical infeasibility should be documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

Step 3 – Rank control technologies by control effectiveness. All remaining control alternatives not eliminated in Step 2 are ranked and then listed in order of overall control effectiveness for the pollutant

[8] U.S. Environmental Protection Agency. New Source Review Workshop Manual – Draft. North Carolina: Office of Air Quality Planning and Standards, 1990.

under review, with the most effective control alternative at the top. A list should be prepared for each pollutant and for each emissions unit (or grouping of similar units) subject to a BACT analysis.

Step 4 – Evaluate most effective controls and document results. After the identification of available and technically feasible control technology options, the energy, environmental, and economic impacts of each such option are taken into account and the technology for control of emissions of the pollutant is selected at Step 4. Section 6.1.2 describes the economic analyses used in this BACT analysis.

Step 5 – Select BACT. The BACT emission limitation determination is made at Step 5.

6.1.2 General Principles

The BACT analysis for the Project is also based on the following concepts:

- There is no single prescriptive approach to determining the appropriate control technology and emission limitation for a given project
- BACT does not redefine the facility as proposed (including fuels)
- The control technology must be available and feasible for this specific project
- Emission limitations are defined on a "case-by-case" analysis that considers site specific factors
- Emission limitations must be "achievable" on a long-term, day in and day out, basis

There is no prescriptive approach to performing a case-by-case control technology and emission limitation analysis. PSD permitting authorities determine emission limitations on a case-by-case basis. These case-by-case determinations must take into account source-specific and site-specific characteristics. This is not a "cookie-cutter" approach, and there is no single right answer to determining either the appropriate control technology or the appropriate emission limitation for a specific source or for a specific pollutant.

KDHE is not required to set any emission limitation at the most stringent emission limitation that has been demonstrated by a facility using similar emissions control technology. Similarly, an emission limitation does not need to be set at the most stringent emission limitation found in another permit. Rather, KDHE has the authority and the ability to evaluate and determine the proper control technologies and emissions limitations for a particular project based on project-specific factors, including location. The BACT process does not require that each determination establish an emission limitation that is equal to or more stringent than the most stringent previous determination.

Further, in establishing emission limitations, KDHE must confirm that those limitations are achievable by the specific facility that is subject to them: (1) over the life of the facility; and (2) during all operating conditions, not just ideal conditions. The use of a safety factor or margin is well-established in the air permitting context to appropriately account for the uncertainty and operational variability that will occur over the life of a facility. This safety factor must be sufficient to allow a permit holder to comply on a continuous basis. Emission limitations are not required to be based on the lowest emissions rate or highest control efficiency ever documented by a similar facility for a short-term period. The emission limitations must account for a full range of operating conditions and the inherent variability of complex fuel combustion and air pollution control systems.

In order to be considered in the BACT process, a control technology must be commercially available (*i.e.,* it must be offered for sale at commercial scale through commercial channels). Permit applicants are not required to explore Research &Development (R&D) projects to determine whether or not a particular technology is potentially feasible. In addition, in order to be considered feasible technology for purposes of inclusion in an analysis, a particular technology must have been previously demonstrated, on a long-term basis, at commercial scale.

In its March 2011 guidance, EPA affirmed that a BACT review for a project should not operate to redefine the project. "EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant. BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility." The March 2011 guidance continues, "The 'redefining the source' issue is ultimately a question of degree that is within the discretion of the permitting authority." Similarly, EPA's March 2011 "Guidance for Determining Best Available Control Technology for Reducing Carbon Dioxide Emissions from Bioenergy Production" states, "However, while Step 1 is intended to capture a broad array of potential options for pollution control, this step of the process is not without limits. EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant. BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility."

6.1.3 Economic Analyses

This section contains information regarding the economic analyses and how they were performed in Step 4 for each piece of equipment. Economic analyses were performed for add-on controls for auxiliary equipment and these tables are located in Appendix E.

For the controls that require an economic analysis, capital costs include the initial cost of components intrinsic to the complete control system. For both oxidation catalyst and SCR systems, these capital costs would include the catalyst modules, transition piece, support frame, piping, provisions for catalyst cleaning and removal, instrumentation, and installation costs. Additionally, the SCR system requires the installation of an ammonia injection system. Annual costs consist of the financial efficiency losses, parasitic loads, and revenue loss from operation of the control system; overhead, maintenance, labor, raw materials and utilities are included.

Capital and operating costs have been estimated in accordance with EPA guidance. The capital cost estimating technique used in this analysis is based on a factored method of determining direct and indirect installation costs. This technique is a modified version of the "Lang Method," where installation costs are expressed as a function of known equipment costs. This method is consistent with the latest EPA guidance manual [Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual] on estimating control technology costs (EPA 2002).

Purchased equipment costs represent the delivered cost of the control equipment, auxiliary equipment, and instrumentation. Auxiliary equipment consists of all structural, mechanical, and electrical components required for continuous operation of the device. Depending on the control strategy that is used, these costs may include such items as reagent storage tanks, supply piping, the engine outlet transition piece, a catalyst removal crane, spare parts, and the catalyst and air dilution system. In this BACT evaluation, basic equipment costs were obtained from data provided by vendors and from recent projects with similar units. Instrumentation is usually not included in the basic equipment cost, so the OAQPS manual allows that instrumentation may be estimated to be 10 percent of the basic equipment cost.

Direct installation costs consist of the direct expenditures for materials and labor including site preparation, foundations, structural steel, insulation, erection, piping, electrical, painting, and enclosure structures. Indirect installation costs include engineering and supervision of contractors, construction and field expenses, construction fees, contingencies, and additional permits and licensing costs.

Direct installation costs are expressed as a function of the purchased equipment cost and are based on the average installation requirements of typical systems. Indirect installation costs are designated as a

percentage of the total direct cost (purchased equipment cost plus the direct installation cost) of the system. Other indirect costs include equipment start-up and performance testing, contingency funds, working capital and interest during construction.

Annualized costs are comprised of direct and indirect operation costs. Direct costs include electricity losses, labor, maintenance, replacement parts, raw materials, and utilities. Indirect operating costs include overhead, taxes, insurance, general administration, contingencies, and capital charges. Annualized cost factors used to estimate total annualized costs for the SCR and oxidation catalyst systems are presented in their respective discussions in the sections that follow. These tables are consistent with the EPA guidance on estimating control technology costs (EPA 2002).

Direct operating labor costs vary according to the system operating mode and operating time. Labor supervision is estimated as 15 percent of operating labor. Maintenance costs have been included and are itemized as appropriate. Replacement part costs, such as the cost to replace an aged or failed catalyst, have been included where appropriate. Reagent and utility costs are based upon estimated annual consumption. Based on the experience of other facilities, catalyst is assumed to require replacement at a minimum of every three years due to failure or aging.

Most indirect operating costs are calculated as a percentage of the total capital cost. The indirect capital costs are based on the capital recovery factor (CRF), defined as:

$$CRF = \frac{i \cdot (1+i)^n}{(1+i)^n - 1}$$

Where:

i = interest rate
n = equipment economic life (years)

A control system's economic life is typically 10 to 20 years. In this analysis, a 20-year equipment economic life (typical length of financing) was used. The average interest rate is assumed to be seven percent. The CRF is calculated to be 0.094.

The cost-effectiveness for each system is calculated by dividing the annualized cost of the available control technology by the annual emissions reduction. The annual emissions reduction is the difference between the baseline emission rate and the controlled emission. All BACT capital and annual cost tables are contained in Appendix E.

6.1.4 GHG BACT Process

Based on EPA GHG Guidance,[9] the GHG greenhouse gases BACT process is similar to the PSD BACT process summarized above. Potential control strategies are identified at Step 1 and technologically infeasible options are then eliminated at Step 2. The remaining technically feasible control technologies are ranked at Step 3. The most effective control technologies from an environmental, energy, and economic perspective are evaluated and the most appropriate control technology is selected at Step 4. Finally, the BACT emission limitation is made at Step 5. The general principles of PSD BACT analysis discussed above are equally applied to the GHG BACT process.

6.2 BACT Technology and Emission Limitations for Similar Units

The first step in the "top-down" BACT process is the identification of potentially available control technologies. A good source of information on such technologies is EPA's RACT/BACT/LAER Clearinghouse (RBLC) database maintained on EPA's Technology Transfer Network website at www.epa.gov/ttn/catc. This database includes recent BACT determinations for similar projects.

Advanced queries of the database were conducted to identify control technology determinations from January 2003 to April 2013 for sources similar to the RICE to be used for the Project. Queries were also made for the Project's auxiliary equipment for the same time period. The results of the RBLC queries can be found in Appendix D in Tables D1 to D7.

To identify previous control technology determinations for comparable sources, two types of queries were run for each set of operational modes. The first query was a "basic search" in which the RBLC database was searched for:

- Internal Combustion Engines (>500 hp), 17.130 – Natural gas combustion

In addition to the RBLC database search, other known RICE electric generating units (EGU) projects that are known by TradeWind and permitted (but filed under a different category in the RBLC) were located within the RBLC and included in the tables as well. All known projects that used natural gas engines of similar engine size (4-10 MW) and were subject to PSD review were included in the RBLC search. To the extent practicable, clearly non-applicable projects were removed from the RBLC tables presented in this application. For example, the following process types are incorrectly used in the RBLC to identify internal combustion engine projects; therefore, these categories were also examined:

[9] PSD and Title V Permitting Guidance for Greenhouse Gases, U.S. EPA, Office of Air Quality Planning and Standards, March 2011.

- Boilers (>250 MMBtu/hr), 11.310 - Natural gas combustion
- Combined Cycle Combustion Turbines (<25 MW), 15.210 - Natural gas combustion

Additionally, the most recent and relevant permit for comparison to this application is Mid-Kansas Electric, LLC's Rubart Station PSD air permit issued by KDHE in January 2013. Although Rubart Station proposed to use Caterpillar engines instead of Wärtsilä, the projects are very similar and Rubart Station BACT limits have been included in this BACT analysis.

Permitted BACT emission rates for other internal combustion engines have been compared to the RICE to be used in the Project. The best comparison is made to other turbo-charged, four-stroke, lean-burn machines (turbo charged, as opposed to naturally aspirated). However, differences in size (MW) and speed (rpm) of some other permitted engines makes such units dissimilar to the Project RICE. EPA's RBLC provides insufficient data to determine if other permitted machines are indeed turbo-charged, four-stroke, lean-burn engines. Most of the RBLC-listed machines are slow speed, gas-compression machines or higher speed, non-turbo machines. These differences must be taken into account when comparing the RICE to be used in this Project to other previously-permitted engines. Of the vendors and engines that are commercially available, Wärtsilä, Jenbacher, and Caterpillar manufacture and sell natural gas-fired reciprocating engines that are appropriate for this Project. However, only Wärtsilä has permitted and *operated* units of this size that are natural-gas fired. Permits for projects that include similar-sized Wärtsilä RICE and the Rubart CAT RICE have been collected by TradeWind. The Wärtsilä permitted emission rates are listed in Table 6-3, below. These projects represent the most applicable technology that is similar to this Project.

Table 6-3. Emission Rates for Engines Similar to Project Engines at Full Load (g/bhp-hr)

Plant	State	NO_x[A]	CO[A]	VOC[A]	PM_{10} total[A]
Western 102	Nevada	0.054	0.087	0.087	0.094
Plains End 2	Colorado	0.059	4.000	1.000	0.102
Goodman	Kansas	0.097	0.097	0.097	--
Humboldt	California	0.064	0.086	0.106	0.075
Pearsall	Texas	0.087	0.308	0.308	0.181
Antelope	Texas	0.052	0.096	0.157	0.075
Lea County	New Mexico	0.054	0.104	0.104	0.080
Woodland 3	California	0.053	0.084	0.074	0.052
Hutchinson	Minnesota	0.030	0.746	0.299	0.082
Quail Brush	California	0.048	0.057	0.057	0.050
Greenville Electric	Texas	0.086	0.308	0.308	0.181
Mid-Kansas Rubart Station (Caterpillar)	Kansas	0.07	0.13	0.20	0.044

[A] The values are originally given in different units and here converted to similar units for comparison purposes (rounded to integral values). Also, many of these plants were not subject to PSD review. All units have CO catalysts and SCR, except for Hutchinson which does not have a CO catalyst. Note that emissions levels vary based on engine size, type and location.

6.3 New Source Performance Standards

6.3.1 Subpart JJJJ

Subpart JJJJ—Standards of Performance for Stationary Spark Ignition Internal Combustion Engines became effective March 18, 2008.[10] The RICE engines are subject to the NSPS Subpart JJJJ limits for non-emergency spark ignited (SI) natural gas engines greater than 500 HP manufactured after July 1, 2010. The applicable emission limitations are listed in Section 5.2.

All BACT emission limitations for the Project are more stringent than the applicable NSPS.

6.4 BACT For Nitrogen Oxides (NO_x) – RICE

6.4.1 STEP 1. Identify All Potential Control Technologies

NO_x is primarily formed in combustion processes in three ways: 1) the combination of elemental nitrogen with oxygen in the combustion air within the high temperature environment of the combustor (thermal

[10] "Standards of Performance for Stationary Spark Ignition Internal Combustion Engines," Title 40 Code of Federal Regulations, Part 60, Subpart JJJJ. 2011 ed.

NO_x); 2) reactions of nitrogen with hydrocarbon radicals from the fuel (prompt NO_x); and 3) the oxidation of nitrogen contained in the fuel (fuel NO_x). Natural gas contains negligible amounts of fuel-bound nitrogen, although some molecular nitrogen is present. Therefore, it is assumed that essentially all NO_x emissions from the engines originate as thermal NO_x. The rate of formation of thermal NO_x is a function of residence time and free oxygen and is exponential with peak flame temperature. NO_x control techniques are aimed at controlling one or more of these variables during combustion. Controlling the air-to-fuel ratio can reduce the amount of NO_x [11]

The RICE for the Project will be lean-burn, 4-stroke engines, which can also be characterized as clean-burn engines. The term "clean-burn" technology refers to engines designed to reduce NO_x by operating at high air-to-fuel ratios. The RICE will be equipped with turbo chargers which increase the volume of air in the combustion chamber. Lean-burn engines typically have lower oxides of nitrogen (NO_x) emissions than rich-burn engines.

Other control methods utilize add-on equipment to remove NO_x from the exhaust gas stream after its formation. The most common control techniques involve the injection of ammonia or urea into the gas stream to reduce the NO_x to molecular nitrogen and water. Ammonia is either injected into the engine combustion chamber (non-selective catalytic reduction [NSCR]) or injected with the use of a catalyst (selective catalytic reduction [SCR]). NSCR may be used for rich-burn engines, but is not feasible on lean-burn engines.

6.4.2 STEP 2. Identify Technically Feasible Control Technologies

6.4.2.1 Non-Selective Catalytic Reduction (NSCR)

NSCR uses the residual hydrocarbons and CO in the rich-burn engine exhaust as a reducing agent for NO_x. In an NSCR, hydrocarbons and CO are oxidized by O_2 and NO_x. The excess hydrocarbons, CO, and NO_x pass over a catalyst that reduces NO_x to N_2.

The NSCR technique is effectively limited to engines with normal exhaust oxygen levels of 4 percent or less. This includes four-stroke rich-burn naturally-aspirated engines and some four-stroke rich- burn turbo-charged engines. Engines operating with NSCR require tight air-to-fuel control to maintain high reduction effectiveness without high hydrocarbon emissions. To achieve effective NO_x reduction

[11] EPA. Compilation of Air Pollutant Emission Factors, Fifth Edition. (AP-42), Section 3.2 (7/00).

performance, the engine may need to be run with a richer fuel adjustment than normal. This exhaust excess oxygen level is usually closer to 1 percent.

Lean-burn engines cannot be retrofitted with NSCR control because of the reduced exhaust temperatures. **Because lean-burn engines cannot be fitted with NSCR, NSCR is not technically feasible for application to the RICE.**

6.4.2.2 Selective Catalytic Reduction (SCR)

SCR is a post-combustion technology that employs ammonia in the presence of a catalyst to convert NO_x to nitrogen and water. The function of the catalyst is to lower the activation energy of the NO_x decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, deactivation due to aging, ammonia slip (ammonia that is left unreacted and exits out the stack) emissions, and the design of the ammonia injection system.

SCR represents state-of-the-art controls for lean-burn four-stroke engine NO_x removal. This technology is also commonly used on natural gas-fired engines.

The temperature of the exhaust in an SCR dictates the type of catalyst that will be used. Typically, for exhaust gases on the higher end of the normal operating range (450 to 850 degrees Fahrenheit), a high-temperature catalyst such as vanadium or zeolite is required. **Because SCRs are commercially available and have been used on engines of this size, SCR is technically feasible for application to the RICE.**

6.4.2.3 Lean-Burn Combustion

The Project's RICE will be lean-burn, four-stroke engines. Lean-burn engines may operate up to the lean flame extinction limit, with exhaust oxygen levels of 12 percent or greater. The air-to-fuel ratios of lean-burn engines range from 20:1 to 50:1 and are typically higher than 24:1. The Project's RICE lean-burn engines are also characterized as clean-burn engines. Engines operating at high air-to-fuel ratios (greater than 30:1) may require combustion modification to promote stable combustion with the high excess air. The RICE are designed with a turbo charger which is used to force more air than non-turbo charged engines into the combustion chamber. Lean-burn engines typically have lower oxides of nitrogen (NO_x) emissions than rich-burn engines.[12]

[12] EPA. Compilation of Air Pollutant Emission Factors, Fifth Edition. (AP-42), Section 3.2 (7/00).

Steady-state controlled NO_x emissions using no control or only lean-burn combustion range from 0.19 to 20.2 g/bhp-hr according to the RBLC database (Table D-1). The NO_x emissions are highly variable depending on the specific RICE and its use. Each vendor that offers RICE has different NO_x emission levels, even though they all may use lean-burn technology.

Because lean-burn combustion with clean-burn technology is standard on engines like those to be used for the Project, it is a technically feasible option for the RICE.

6.4.2.4 Summary of the Technically Feasible Control Options

The technical feasibility of the NO_x control options for the engines is summarized in Table 6-4. The expected performance (steady state) has been determined considering the vendor guarantees.

Table 6-4. Summary of Technically Feasible NO_x Control Technologies for the RICE

Control System		Expected Performance (lb/hr)	Technical Feasibility	Comments
Combustion Controls	Lean-burn Combustion	34.70	Feasible	Standard on the Project's RICE
Post Combustion Controls	Non-Selective Catalytic Reduction	N/A	Not Feasible	Only used on rich-burn engines
	Selective Catalytic Reduction	1.45	Feasible	SCR is part of standard package for the Project's RICE

6.4.3 STEP 3. Rank the Technically Feasible Control Technologies

Add-on controls are a technically feasible option on the Project's RICE. The RICE will come as lean-burn engines and include SCR as part of the standard packages. Although the SCR is included with the RICE engines, it is an add-on control. Therefore, lean-burn combustion will be considered as baseline.

The technically feasible NO_x control technologies for the RICE are ranked by control effectiveness in Table 6-5.

Table 6-5: Ranking of Technically Feasible NO_x Control Technologies for the RICE

Control Technology	Reduction (%)	Controlled Emission Level (lb/hr)
Lean-burn combustion/ with SCR	96	1.45
Lean-burn combustion	Baseline	34.70

6.4.4 STEP 4. Evaluate the Most Effective Controls

6.4.4.1 Environmental, Energy, and Economic Feasibility of Control Options

The next step in the top-down BACT analysis is to review each of the technically feasible control options for environmental, energy, and economic impacts. First, all technically feasible controls will be discussed for environmental and energy impacts. Next, if the top control is not chosen, an economic analysis to determine capital and annual control costs in terms of cost-effectiveness (i.e., dollars per ton of pollutant removed) of each control system will be conducted. Because TradeWind has selected the top control, the following information is presented for informational purposes only.

6.4.4.2 Selective Catalytic Reduction (SCR)

Energy Impacts

As with all add-on controls, operation of an SCR system results in a loss of energy due to the pressure drop across the SCR catalyst. To compensate for the energy loss in the SCR system, additional natural gas combustion is required to maintain the net energy output, which also results in additional air pollutant emissions. However, the extra fuel required for the controls does not outweigh the benefit of reducing emissions of NOx.

Environmental Impacts

Urea, which is decomposed in an external reactor to form ammonia, will be used in the SCR. The SCR system consists of an ammonia injection system and a catalytic reactor. Unreacted ammonia may escape through to the exhaust gas. This is commonly called “ammonia slip.” It is estimated that ammonia slip from an SCR on this size of engine could be 10 ppm; this may be considered to be an environmental impact. The ammonia that is released may also react with other pollutants in the exhaust stream to create fine PM_{10} in the form of ammonium salts. SCR catalysts must also be replaced on a routine basis. In some cases, these catalysts may be classified as hazardous waste. This typically requires either returning the material to the manufacturer for recycle and reuse or disposal in permitted landfills. None of this outweighs the benefit of reducing emissions of NO_x because of the environmental and health benefits of reducing NO_x emissions.

Economic Impacts

Engine manufacturers currently install SCRs as standard equipment on the RICE that combust natural gas for power generation in the United States. As SCR is the top control technology listed and because SCR is

standard equipment on the engines being considered, there is no need to calculate an annualized cost of the control for the purposes of this analysis.

6.4.4.3 Lean-Burn Combustion

Energy Impacts

Lean-burn combustion and clean-burn technology are usually accompanied by an efficiency penalty (typically 2 to 3 percent) and an increase in power output (typically 5 to 6 percent). The increase in power output results from the increase in mass flow required to maintain engine inlet temperature at manufacturer's specifications. Because there is a power increase, no energy impacts are associated with lean-burn combustion and clean-burn technology.

Environmental Impacts

Lean-burn combustion may increase CO and VOC emissions. However, this increase does not outweigh the advantage of decreased NO_x emissions because NO_x emissions are considered to be more detrimental to the environment and human health.[13]

Economic Impacts

The RICE vendors under consideration currently install lean-burn combustion with clean-burn technology as standard on the engines. Because lean-burn combustion is standard equipment on the engines, there is no calculated annualized cost of the control for the economic impacts evaluation.

The maximum technically feasible control applied to RICE is SCR with lean-burn combustion. Because this is the highest level of add-on control for engines of this size, BACT for control of NO_x emissions from the RICE is lean-burn combustion with clean-burn technology with SCR.

6.4.5 STEP 5. NO_x BACT Emission Limitation

BACT determinations shown in the RBLC (Table D-1) for engines that are in the 4.5- to 9.3-MW size range located in attainment areas were in the range of 0.07 gram per brake horsepower-hour (g/bhp-hr) to 20.2 g/bhp-hr using either lean-burn combustion (or clean burn technology) or SCR for natural gas-fired engines.

The BACT emission limitation for NO_x is 1.45 lb/hr for steady state loads of 50 percent and higher, based on vendor guarantees. This rate is equivalent to 0.053 g/hp-hr for loads of 50 percent and higher. This represents the lowest emission rates that can be achieved for these types of natural gas RICE EGUs.

[13] EPA. Compilation of Air Pollutant Emission Factors, Fifth Edition. (AP-42), Section 3.2 (7/00).

6.5 BACT FOR Carbon Monoxide (CO) – RICE

6.5.1 STEP 1. Identify Potential Control Strategies

CO results from incomplete combustion. Control of CO is typically accomplished by providing adequate fuel residence time and a high temperature in the combustion zone to ensure complete combustion. CO emissions may indicate early quenching of combustion gases on cylinder walls or valve surfaces. Lean-burn engines typically have higher CO emissions and lower NO_x emissions due to the air-to-fuel ratios at which they both operate.

CO emissions from engines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Front-end control involves controlling the combustion process to suppress CO formation. Post-combustion control involves the use of catalytic oxidation.

The technologies identified for reducing CO emissions from the engines are an oxidation catalyst (also referred to as a CO catalyst) and combustion controls. The standard technology for reducing CO emissions is to maintain "good combustion" through proper control and monitoring of the combustion process through the air-to-fuel ratio. A survey of the RBLC database (Table D-2) indicates that combustion controls is the most prevalent BACT control, with several oxidation catalysts listed as BACT.

6.5.2 STEP 2. Identify Technically Feasible Control Technologies

6.5.2.1 Oxidation Catalyst

Oxidation catalysts are a post-combustion technology which does not rely on the introduction of additional chemicals, such as ammonia or urea with SCR, for a reaction to occur. The oxidation of CO to CO_2 utilizes excess air present in the engine exhaust; the activation energy required for the reaction to proceed is lowered in the presence of a catalyst. Products of combustion are introduced into a catalytic bed, with the optimum temperature range for these systems being between 700°F and 1,100°F. At higher temperatures, catalyst sintering may occur, potentially causing permanent damage to the catalyst. The addition of a catalyst bed onto the engine exhaust will create a pressure drop, resulting in back pressure to the engine. This has the effect of reducing the efficiency of the engine and the power generating capabilities.

The use of oxidation catalysts is a technically feasible method for controlling CO emissions from the RICE.

6.5.2.2 Combustion Control

"Good combustion practices" include operational and incinerator design elements to control the amount and distribution of excess air in the flue gas to ensure that there is enough oxygen present for complete combustion (controlling the air-to-fuel ratio).

Good combustion practices are a technically feasible method of controlling CO emissions from the RICE.

6.5.2.3 Summary of the Technically Feasible Control Options

The technical feasibility of the CO control options for the RICE being considered are summarized in Table 6-6. The expected performance has been determined considering the performance of existing systems, vendor guarantees, permitted emission limitations, and the design requirements for the engines.

Table 6-6. Summary of Technically Feasible CO Control Technologies for the RICE

Control System		Expected Performance (lb/hr)	Feasibility	Comments
Combustion Control		46.36	Feasible	Standard on the RICE. Not an add-on control.
Post Combustion Controls	Oxidation Catalyst	2.67	Feasible	Produces CO_2 emissions. Standard on the RICE.

6.5.3 STEP 3. Rank the Technically Feasible Control Technologies

The technically feasible CO control technologies for the RICE are ranked by control effectiveness in Table 6-7.

Table 6-7. Ranking of Technically Feasible CO Control Technologies for the RICE

Control Technology	Reduction (%)	Controlled Emission Level (lb/hr)
Oxidation Catalyst	94	2.67
Combustion Control	Not applicable (baseline)	46.36

6.5.4 STEP 4. Evaluate the Most Effective Control Technologies

6.5.4.1 Environmental, Energy, and Economic Feasibility of Control Options

Because TradeWind has selected the top control, the following information is presented for informational purposes only.

EXHIBIT 4

to Sierra Club Comments

Sierra Club TEP RICE Comments
Exhibit 4

BACT Determination Detail

Category

Source Category:	ICE: Spark Ignition, Natural Gas
SIC Code	
NAICS Code	2211

Emission Unit Information

Manufacturer:	Wartsila
Type:	4-cycle, lean burn
Model:	18V220SG
Equipment Description:	
Capacity / Dimentions	3870 hp
Fuel Type	Natural Gas
Multiple Fuel Types	
Operating Schedule (hours/day)/(days/week) /(weeks/year)e	Variable (/ /)
Function of Equipment	16 engines driving generators, 44 MW peaking plant

Bact Information

NOx Limit	9
NOx Limit Units	ppmvd @ 15% O2
NOx Average Time	
NOx Control Method	
NOx Control Method Desc	SCR
NOx Percent Control Efficiency	
NOx Cost Effectiveness (%/ton)	
NOx Incremental Cost Effectiveness (%/ton)	
NOx Cost Verified (Y/N)	
NOx Dollar Year	
CO Limit	56
CO Limit Units	ppmvd @ 15% O2
CO Average Time	
CO Control Method	
CO Control Method Desc	Oxidation catalyst
CO Percent Control Efficiency	
CO Cost Effectiveness (%/ton)	
CO Incremental Cost Effectiveness (%/ton)	

CO Cost Verified (Y/N)	
CO Dollar Year	
VOC Limit	25
VOC Limit Units	ppmvd @ 15% O2
VOC Average Time	
VOC Control Method	
VOC Control Method Desc	Oxidation catalyst
VOC Percent Control Efficiency	
VOC Cost Effectiveness (%/ton)	
VOC Incremental Cost Effectiveness (%/ton)	
VOC Cost Verified (Y/N)	
VOC Dollar Year	
PM10 Limit	**0.02**
PM10 Limit Units	**g/bhp-hr**
PM10 Average Time	
PM10 Control Method	
PM10 Control Method Desc	
PM10 Percent Control Efficiency	
PM10 Cost Effectiveness (%/ton)	
PM10 Incremental Cost Effectiveness (%/ton)	

PM10 Cost Verified (Y/N)	
PM10 Dollar Year	
SOx Limit	**0.000829**
SOx Limit Units	**lb/MMBtu**
SOx Average Time	
SOx Control Method	
SOx Control Method Desc	
SOx Percent Control Efficiency	
SOx Cost Effectiveness (%/ton)	
SOx Incremental Cost Effectiveness (%/ton)	
SOx Cost Verified (Y/N)	
SOx Dollar Year	
Other Limit	10
Other Limit Units	NH3 ppmvd
Other Average Time	
Other Control Method	
Other Control Method Desc	
Other Percent Control Efficiency	
Other Cost Effectiveness (%/ton)	
Other Incremental Cost Effectiveness (%/ton)	

Other Cost Verified (Y/N)

Other Dollar Year

Project / Permit Information

Application/Permit No.:	220
Application Completeness Date:	
New Construction/Modification:	New Construction
ATC Date:	04-17-2001
PTO Date:	05-22-2002
Startup Date:	09-01-2001
Technology Status:	BACT Determination
Source Test Available:	Yes
Source Test Results:	October 16-19, 2001 January 21, 2003 Range Average Engine #6 Engine #14 O2, % (dry) 11.85 - 12.57 12.30 12.19 12.65 PPMVD@15%O2: NOx 4.02 - 5.64 4.82 7.1 7.42 CO 9.2 - 29.3 16.3 19.0 22.5 NMHC as C1 3.0 - 5.8 4.3 3.8 4.2 NH3 0.32 - 0.82 0.44 0.64 0.88 The 2001 test was the initial source test (all 16 engines), and the 2003 test was the most recent annual test (2 engines, selected by APCD). Each engine test consisted of three 20-minute measurements. An APCD observer was present in both cases.

Facility / District Information

Facility Name:	NEO California Power, LLC
Facility Zip Code:	

Sierra Club TEP RICE Comments
Exhibit 4

Facility County:	
District Name:	Tehama County APCD
District Contact:	Curtis Wentworth
Contact Phone No.:	530-527-3717
Contact E-Mail:	

Notes

Notes:	CARB Guidance for Permitting of Electrical Generation Technologies Emissions may exceed these limits during startups and shutdowns (max of one hour each case). NOx and CO emissions from all 16 engines combined limited to 24.99 tons/year each (to avoid offsets). Engine operation limited to 6,090 hrs per year per engine (to ensure NOx and CO caps are met) As of the February 2004 test, the catalysts had not yet been cleaned.

Report Error In Determination

EXHIBIT 5

to Sierra Club Comments

Section II: Other LAER/BACT Determinations

Application No.: 220

Equipment Category – I.C. Engine, Stationary, Non-Emergency

1. GENERAL INFORMATION

DATE: 5/14/2004

A. MANUFACTURER: Wartsila

B. TYPE: Four-Cycle, Lean-Burn

C. MODEL: 18V220SG

D. STYLE:

E. APPLICABLE AQMD RULES:

F. COST: $ (NA) SOURCE OF COST DATA:

G. OPERATING SCHEDULE: HRS/DAY DAYS/WK WKS/YR

2. EQUIPMENT INFORMATION

APP. NO.: 220

A. FUNCTION: Sixteen engines driving generators, constituting 44 MW peaking plant. Power is sold to PG&E grid.

B. MAXIMUM HEAT INPUT:

C. MAXIMUM THROUGHPUT: 3870 hp

D. BURNER NFORMATION: NO.: TYPE:

E. PRIMARY FUEL: Natural Gas

F. OTHER FUEL: None

G. OPERATING CONDITIONS: Peaking service

3. COMPANY INFORMATION

APP. NO.: 220

A. NAME: NEO California Power, LLC

B. SIC CODE: 4911

C. ADDRESS: 970 Diamond Avenue
CITY: Red Bluff STATE: CA ZIP: 96080

D. CONTACT PERSON: Tim Hemig

E. PHONE NO.: 760-268-4000

4. PERMIT INFORMATION

APP. NO.: 220

A. AGENCY: Tehama County APCD

B. APPLICATION TYPE: new construction

C. AGENCY CONTACT PERSON: Curtis Wentworth

D. PHONE NO.: 530-527-3717

E. PERMIT TO CONSTRUCT/OPERATE INFORMATION: P/C NO.: 220 ISSUANCE DATE: 4/17/2001
☐ CHECK IF NO P/C P/O NO.: 220 ISSUANCE DATE: 5/22/2002

F. START-UP DATE: Late fall 2001

5. EMISSION INFORMATION

APP. NO.: 220

A. PERMIT

A1. PERMIT LIMIT: PPMVD@15%O2 (g/bhp-hr): NOx-9 (0.15), NMHC-25 (0.15), CO-56 (0.6). Ammonia not to exceeed 10 ppmvd. SOx not to exceed .000829 lb/MMBtu. PM10 not to exceed .02 g/bhp-hr. Emissions may exceed these limits during startups and shutdowns (maximum of one hour each case). Aggregate NOx and VOC from all 16 engines limited to 24.99 tons per year (to avoid offsets). Engine operation limited to 6,090 hours per year per engine (to insure NOx and VOC caps are met).

A2. BACT/LAER DETERMINATION: Above concentration limits on NOx, CO and VOC.

A3. BASIS OF THE BACT/LAER DETERMINATION: CARB Guidance for Permitting of Electrical Generation Technologies

B. CONTROL TECHNOLOGY

B1. MANUFACTURER/SUPPLIER: Wartsila (engines), Miratech (selective catalytic NOx reduction systems), Oxicat (oxidation catalyst)

B2. TYPE: Engines are turbocharged and aftercooled. Selective catalytic reduction (SCR) for NOx control. Oxidation catalyst for control of CO and NMHC.

B3. DESCRIPTION: SCR systems (one per engine) are catalytic reactors (Miratech Model HUG EM77/6) promoting reaction between injected urea and NOx to form N2 and H2O. Unreacted urea produces ammonia emissions. The oxidation catalyst on each engine exhaust, immediately following SCR catalyst, promotes oxidation of CO and hydrocarbons (and possibly ammonia) by residual flue gas O2.

B4. CONTROL EQU PMENT PERMIT APPLICATION DATA: P/C NO.: 220 ISSUANCE DATE: 4/17/2001
P/O NO.: 220 ISSUANCE DATE: 5/22/2002

B5. WASTE AIR FLOW TO CONTROL EQUIPMENT: FLOW RATE:
ACTUAL CONTAMINANT LOADING: BLOWER HP:

B6. WARRANTY: System supplier guaranteed the emission limits in the permit.

B7. PRIMARY POLLUTANTS: NOx, CO, NMHC, PM10

B8. SECONDARY POLLUTANTS: Ammonia

B9. SPACE REQUIREMENT:

B10. LIMITATIONS: B11. UNUSED

B12. OPERATING HISTORY: The engines and emission control systems have been in on-demand service since startup in late fall 2001. No equipment breakdowns caused by the pollution control system have been reported. The operating company contact reports that there has been no problem meeting the emission limits.

B13. UNUSED B14. UNUSED

C. CONTROL EQUIPMENT COSTS

C1. CAPITAL COST: ☐ CHECK IF NSTALLATION COST IS INCLUDED IN EQUIPMENT COST
EQUIPMENT: $ INSTALLATION: $ (NA) SOURCE OF COST DATA:

C2. ANNUAL OPERATING COST: $ (NA) SOURCE OF COST DATA:

5. EMISSION INFORMATION

APP. NO.: 220

D. DEMONSTRATION OF COMPLIANCE

D1. STAFF PERMFORM NG FIELD EVALUATION:
ENGINEER'S NAME: INSPECTOR'S NAME: DATE:

D2. COMPLIANCE DEMONSTRATION: Initial source test on all engines, annual source test on 2 engines selected by APCD, quarterly test on all engines that operate in quarter using portable analyzer (NOx and CO).

D3. VARIANCE: NO. OF VARIANCES: None DATES:
CAUSES:

D4. VIOLATION: NO. OF VIOLATIONS: None DATES:
CAUSES:

D5. MAINTENANCE REQUIREMENTS: Periodic rotation and/or replacement of catalyst blocks

D6. UNUSED

D7. SOURCE TEST/PERFORMANCE DATA RESULTS AND ANALYSIS:
DATE OF SOURCE TEST: 10/16-19/01, 1/21/03, 2/17-18/04 CAPTURE EFFICIENCY:
DESTRUCTION EFFICIENCY: OVERALL EFFICIENCY:
SOURCE TEST/PERFORMANCE DATA:

	October 16-19, 2001		1/21/03		2/17-18/04	
	All 16 Engines		Engine	Engine	Eng.	Eng.
	Range	Average	#6	#14	#14	#15
O2, % (dry vol.)	11.85 - 12.57	12.30	12.19	12.65	11.67	11.89
PPMVD@15%O2:						
NOx	4.02 - 5.64	4.82	7.1	7.42	8.81	7.89
CO	9.2 - 29.3	16.3	19.0	22.5	19.0	19.0
NMHC as CH4	3.0 - 5.8	4.3	3.8	4.2	15.5	14.2
NH3	0.32 - 0.82	0.44	0.64	0.88	1.43	2.84

OPERATING CONDITIONS: 100% load (3870 hp, 2800 kW)

TEST METHODS: The 2001 test was the initial source test (all 16 engines), and the 2003 and 2004 tests were annual tests (2 engines, selected by APCD, each case). The results shown are each an average of three 20-minute measurements. An APCD observer was present in all cases.

6. COMMENTS

APP. NO.: 220

The upward trends in NOx, ammonia and VOC may indicated that the catalysts need more frequent cleaning. A representative from the SCR catalyst manufacturer was present at the 2004 test and commented that the SCR catalyst appeared to be in need of cleaning and that if the catalyst were cleaner the NOx and ammonia emissions would be lower.

EXHIBIT 6

to Sierra Club Comments

United States General Accounting Office

GAO

Report to the Chairman, Subcommittee on Oversight and Investigations, Committee on Energy and Commerce, House of Representatives

September 1990

AIR POLLUTION

Improvements Needed in Detecting and Preventing Violations





142597

RELEASED

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5495

GAO/RCED-90-155

GAO
United States
General Accounting Office
Washington, D.C. 20548

Resources, Community, and
Economic Development Division

B-233555

September 27, 1990

The Honorable John D. Dingell
Chairman, Subcommittee on
Oversight and Investigations
Committee on Energy and Commerce
House of Representatives

Dear Mr. Chairman:

This report responds to your request that we examine the Environmental Protection Agency's (EPA) efforts to ensure that major stationary sources of air pollution do not exceed air pollution control requirements. The report discusses EPA's efforts to (1) require the use of the most effective methods to detect air pollution violations at major sources and (2) impose appropriate enforcement actions when violations are found.

Unless you publicly release its contents earlier, we plan no further distribution of this report until 30 days from the date of this letter. At that time, we will send copies of the report to appropriate congressional committees; the Administrator, EPA; and other interested parties. We will make copies available to others upon request.

This work was performed under the general direction of Richard L. Hembra, Director, Environmental Protection Issues (202) 275-6111. Major contributors to this report are listed in appendix I.

Sincerely yours,

J. Dexter Peach
Assistant Comptroller General

Executive Summary

Purpose

Exposure to unsafe levels of air pollution has been linked to incidences of cancer, lung disease, and other health problems, yet over one-third of the nation's population live in areas that exceeded one or more federal standards for air quality. The Environmental Protection Agency (EPA) estimates that nearly 40 percent of air pollution comes from about 33,500 of the nation's major stationary sources of pollution such as electric utilities, oil refineries, steel mills, and large factories.

Concerned about pollution from major stationary sources, the Chairman, Subcommittee on Oversight and Investigations, House Committee on Energy and Commerce, requested that GAO determine whether EPA (1) uses the most appropriate method for detecting violations at major stationary sources and (2) ensures that appropriate enforcement actions are taken when violations are found.

Background

Each major source has the potential to emit 100 tons or more of pollutants into the air annually, and some can emit that much daily. In light of the potential health risk posed by air pollution, the Clean Air Act provides for a federal/state partnership under which states develop, and EPA approves, State Implementation Plans specifying actions to regulate and control these sources of air pollution, including the issuance of permits specifying acceptable emission levels. EPA and authorized state and local agencies are responsible for detecting, and then abating, violations and for deterring their future occurrence. During 1989, these agencies detected violations of permit or other requirements at about 14 percent of the major stationary sources.

Two primary methods are used to detect violations: on-site inspections and emission monitors. On-site inspections, often lasting less than half a day, are periodic assessments of facility compliance that may include visual observation, review of operating equipment and records, and a check of pollution control equipment. Emission monitors—automated mechanical equipment usually placed in a facility's exhaust or smoke stack—provide direct, accurate measurements of emissions and can operate up to 24 hours per day.

Results in Brief

EPA estimates that emission monitors are 10 times more likely to detect air quality violations than on-site inspections because they measure emissions directly, provide nearly continuous coverage of facility operations, and detect violations that inspectors cannot. Although EPA issued a policy aimed at increasing the use of monitors where feasible, it has

not implemented this policy by developing regulations that (1) establish criteria for determining where monitors are feasible and (2) require monitor use at sources meeting the criteria. As a result, monitors have been installed at only about 1,065, or 11 percent, of the sources where EPA estimates that monitors could be installed. In order to better address the nation's acid rain problems, proposed Clean Air Act amendments call for the use of monitors at 1,100 sources, principally large utilities that emit large quantities of sulfur dioxide, but some of these sources already have monitors installed and EPA has no plans to require additional monitors beyond those called for in the legislation.

When violations are detected, EPA favors cash penalties calculated to offset the economic benefit that violators gained by not complying with air quality requirements. However, over half of the fiscal year 1988 and 1989 violations defined as significant—EPA's highest enforcement priority—were concluded with no cash penalty imposed. This occurred because most enforcement actions against major stationary sources are taken by state and local programs which, for the most part, operate under their own enforcement authority. Proposed changes to the Clean Air Act should improve EPA's ability to increase state and local penalty amounts and encourage state and local agencies to adopt economic benefit penalty policies.

Principal Findings

More Extensive Use of Emission Monitors Warranted

Conditions have changed since the 1970s when the concerns of industry and regulators over monitor cost and reliability caused EPA to limit its emission-monitoring regulations to the newest and biggest major stationary sources. Costs for monitors have become more reasonable for many major sources, to the point where monitor costs are small relative to other pollution control equipment, and monitor reliability has greatly improved. Monitors in Pennsylvania, for example, have collected reliable data over 90 percent of the time. Because of these changed conditions, and the greater detection potential of monitors as compared with inspections, EPA announced a policy in 1988 calling for monitor usage wherever feasible.

EPA, however, has not issued regulations implementing this policy nor has it developed criteria for making such feasibility determinations. Instead, EPA has tried to convince state and local programs to

voluntarily require the use of monitors under their own authorities, but with little success. As a result, only about 1,065 major stationary sources had monitors installed by the end of 1989. Senior EPA compliance officials estimate that monitors may be feasible at about 9,000 more major stationary sources, but they acknowledge the absence of clear criteria for evaluating sources for monitor feasibility.

Although proposed amendments to the Clean Air Act call for EPA to require monitors at about 1,100 major sulfur dioxide sources, some of these sources are among those that have already installed monitors. EPA has no plans to require additional monitors beyond those called for in the proposed legislation, citing insufficient resources to address new and emerging air quality problems and, at the same time, develop criteria and regulations to implement its emission-monitoring policy. Nevertheless, because emission monitors represent a significant improvement in ensuring compliance, GAO believes that EPA development of such regulations is warranted.

Penalties Often Insufficient to Deter Violations

Both the Clean Air Act's administrative penalty authority and EPA's own internal civil penalty settlement policy direct agency enforcement officials to seek cash penalties sufficient to remove the economic benefit to noncomplying sources. However, in fiscal years 1988 and 1989, no cash penalties were assessed in more than half of the significant violator cases at major stationary sources because EPA, in its review and approval of State Implementation Plans, has not required state and local agencies—which conduct the majority of enforcement actions—to assess penalties sufficient to eliminate the economic benefit. GAO's review of eight state and local programs disclosed that none regularly sought to recover economic benefit penalties. For example, GAO found that the $15,000 penalty assessed in one case was $200,000 lower than the estimated economic benefit gained by the violating source. Not collecting sufficient penalties in such cases may place sources that comply at an economic disadvantage to violators.

According to EPA, the primary reason that state and local programs generally do not assess economic benefit penalties is that they often seek only to correct the cause of the violation. EPA can "overfile" and impose larger penalties in such cases, but has generally not done so, citing unclear authority and insufficient resources. Proposed Clean Air Act amendments would broaden EPA's current authority to administratively assess penalties and would allow it to overfile in more cases to ensure that economic benefit penalties are sought. Nevertheless, EPA needs to

take actions to better ensure that state enforcement programs seek economic benefit penalties when violations are detected so that inequities do not occur between firms that comply and those that do not.

Recommendation to the Congress

Currently proposed amendments to the Clean Air Act contain provisions that would broaden EPA's administrative penalty authority to enable it to better ensure that appropriate cash penalties are assessed. GAO supports these proposals and recommends that the Congress include such penalty authority in the final Clean Air Act legislation.

Recommendations to the Environmental Protection Agency

GAO recommends that the Administrator, EPA

- implement EPA's emission-monitoring policy by developing regulations that (1) establish criteria for determining where monitors are feasible and (2) require monitor use at all sources meeting the criteria and
- require EPA enforcement staff to (1) use available enforcement authority to overfile to the maximum extent possible when states assess inadequate penalties and (2) undertake efforts to include specific standards for assessing economic benefit penalties in the next revisions to State Implementation Plans.

Agency Comments

GAO discussed the report's contents with appropriate EPA, state, and local officials, and their comments have been incorporated as appropriate. As directed by the Subcommittee Chairman, GAO did not obtain official agency comments on a draft of this report.

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Abbreviations

CEM	continuous emissions monitors
EPA	Environmental Protection Agency
GAO	General Accounting Office
NAAQS	National Ambient Air Quality Standards
NESHAPS	National Emissions Standards for Hazardous Air Pollutants
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
RACT	Reasonably Available Control Technology
SIP	State Implementation Plan
SO_2	sulfur dioxide
VOC	volatile organic compound

Introduction

As the Congress considers significant changes to the Clean Air Act, controlling air pollution continues to be a difficult task. Although significant progress has been made in reducing air pollution, the Environmental Protection Agency (EPA) reported in 1990 that more than 120 million Americans lived in areas that exceeded one or more federal standards for acceptable air quality. Increased incidences of cancer, lung disease, and other illnesses have been linked to air pollution.

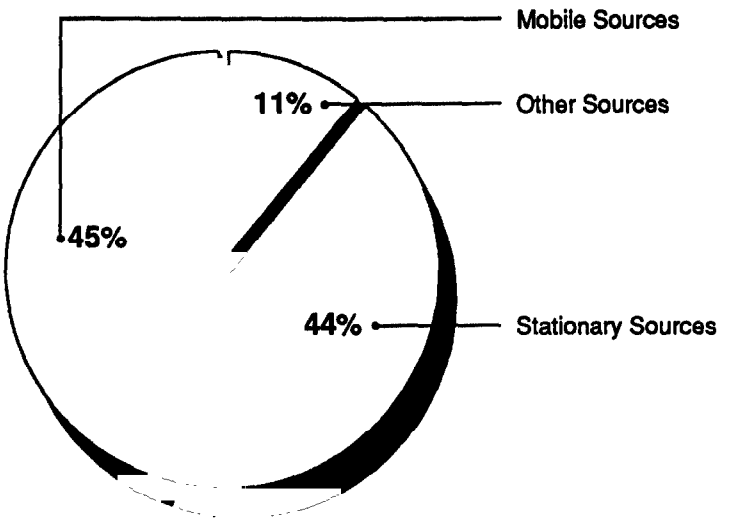
Whether the air we breathe is safe or not depends on many factors, but principally, it depends on the amount of emissions from over 170 million mobile sources and an estimated 300,000 stationary sources of air pollution. Mobile sources, such as cars, trucks, buses, and aircraft, are believed to account for nearly half of the emissions of the six criteria pollutants,[1] including over two-thirds of the carbon monoxide emissions and nearly one-third of the volatile organic compounds (VOCs). Stationary sources such as electric utilities, factories, and commercial buildings are responsible for most of the remaining emissions. These sources emit 96 percent of the sulfur dioxide (SO_2), 58 percent of the nitrogen oxides (NO_x), and 62 percent of the particulate matter, as well as contributing about 51 percent of total VOC emissions—a major contributor to the formation of ozone, generally referred to as "smog."

Emissions from most mobile and stationary sources are difficult to monitor and control because of their large numbers and diversity of operations. However, major stationary sources—comprising about 33,500 of the nation's largest facilities[2] —are more readily monitored and controlled. These sources include electric utilities, oil refineries, steel mills, and large factories and, according to EPA, account for nearly 40 percent of the emissions of criteria pollutants nationwide and nearly 85 percent of all stationary source emissions. Figure 1.1 shows the relative contributions of major stationary sources to the nation's air pollution problems.

[1]EPA established National Ambient Air Quality Standards for six health-related pollutants—ozone, carbon monoxide, sulfur dioxide, nitrogen dioxides, particulates, and lead. These pollutants are commonly called "criteria pollutants."

[2]The term "facility" is used throughout this report to describe a major stationary source of air pollution.

Figure 1.1: Contribution of Major Stationary Sources to Air Pollution Nationwide



Source: GAO illustration based on EPA data.

According to EPA officials, control of emissions at major stationary sources is especially important because of their ability to release great quantities of pollutants if uncontrolled. Major stationary sources can release more pollution into the air in one day than many other sources can in one year. Every major stationary source, by definition, has the potential to emit 100 tons of pollutants, or more, annually and some facilities can emit that much pollution daily. For example, SO_2 emissions from one large electric utility in Pennsylvania can reach 75,000 tons annually, or over 205 tons each day. Figure 1.2 shows two major stationary sources producing visible emissions.

EPA, State, and Local Agency Roles in Controlling Stationary Source Emissions

The Clean Air Act provides for a federal-state partnership to be used in addressing environmental problems. The act requires EPA to set national standards for air quality and provides for states and localities to assume the responsibility of designing and implementing control strategies to meet these standards. These control strategies are documented in the State Implementation Plans (SIPs). EPA is responsible for reviewing and approving the SIPs to ensure that they are adequate to attain and maintain compliance with national air quality standards, and for overseeing state and local implementation of these plans. In cases where state or local plans are not approved, EPA promulgates a federal implementation plan for the affected area. States and localities can propose revisions to SIPs for EPA approval at any time, as long as the revised plan will still attain or maintain the national standards.

An essential component of SIPs is the issuance of permits specifying acceptable emissions levels to owners and operators of major stationary sources. EPA and authorized state and local agencies are responsible for detecting violations of these permits and other requirements and, when a violation is discovered, for taking appropriate action to bring the facility back into compliance and to deter future violations. EPA relies heavily on state and local programs to detect and deter violations at major stationary sources. In 1988 and 1989, EPA authorized 107 state and local agencies to carry out provisions of the act. Under EPA approval, funding assistance, and oversight, these agencies carry out over 90 percent of the actions designed to detect and deter violations at stationary sources of air pollution. For example, state and local agencies performed 34,263 of 37,716 inspections, or about 91 percent of all inspections performed, in fiscal year 1988.

Ensuring Compliance Through Detecting and Deterring Violations

EPA, state, and local strategies for controlling stationary source emissions rely, in part, on educating facility owners and operators through the issuance of regulations and guidance, coupled with technical assistance and site-specific permits that translate and tailor these requirements to an individual source's operations. However, once permits spelling out how pollution is to be controlled at individual facilities have been issued, regulators generally rely on two methods to ensure that sources maintain compliance:[3]

[3]EPA also uses stack tests to assess compliance; however, these tests are not considered a primary detection method because they are scheduled by the facility, employ contractors paid by the facility, and are performed infrequently, often only once every 5 years during permit application or renewal, according to EPA.

- periodic on-site inspections, which compare facility emissions and practices with permit levels and conditions, and
- emission-monitoring devices, also known as "continuous emissions monitors" (CEMS), which are mechanical instruments that measure the amount of pollutants leaving a facility on a near-continuous basis.

Section 114 of the Clean Air Act gives EPA the authority to use either or both detection methods, in addition to others, to assess the compliance of any stationary source. The act does not require or prefer one detection method over another, but provides regulators with broad authority to inspect, monitor, test, sample, and review any facility operations that may reasonably be required to assess compliance.

Once violations are detected, bringing the facilities back into compliance and deterring future violations largely depends on regulators taking appropriate, timely actions. In 1977, the Congress added section 120 to the act, which provided EPA with an enforcement mechanism designed specifically to remove financial incentives to noncompliance. In adding this provision to the act, the Congress intended for noncomplying major sources to be penalized an amount equal to the economic value of the noncompliance to the polluter. Otherwise, sources not complying were viewed as obtaining a competitive advantage over firms that had already installed the needed control equipment or changed production processes to meet their emission limitations. This penalty was to be assessed in all cases where EPA found noncompliance to exist and can be waived only if the violation is de minimis or due to specific causes listed in the statute.

Objectives, Scope, and Methodology

Concerned with major stationary sources' potential to significantly contribute to unsafe levels of air pollution when operating in violation of the Clean Air Act's requirements, the Chairman, Subcommittee on Oversight and Investigations, House Committee on Energy and Commerce, requested that we determine

- whether EPA uses the most appropriate method of detecting violations at major stationary sources of air pollution and
- once discovered, whether EPA takes appropriate action to compel compliance at these sites.

To accomplish these objectives, in accordance with agreements with the Chairman's office, we performed work at the following EPA headquarters offices:

- Stationary Source Compliance Division, Office of Air Quality Planning and Standards, Office of Air and Radiation.
- Office of Air Enforcement Counsel, Office of Enforcement and Compliance Monitoring.
- Legal Enforcement Policy Branch, Office of Enforcement and Compliance Monitoring.
- Office of the Assistant Inspector General for Audit, Office of the Inspector General.

We also visited three EPA regions and eight authorized state and local programs within these regions as shown in table 1.1.

Table 1.1: State and Local Offices in EPA Regions III, IV, and IX Included in GAO's Review

EPA region	State agency	Local district
Region III	Pennsylvania Department of Environmental Resources	
Region IV	North Carolina Division of Environmental Management	Mecklenberg County Department of Environmental Protection
Region IX	California Air Resources Board	Bay Area Air Quality Management District
	Arizona Department of Environmental Quality, Office of Air Quality	Maricopa County Bureau of Air Pollution Control
		Pima County Air Quality Control District

We judgmentally selected these regions, states, and localities for geographical coverage, program size, and diversity of sources, and because each had a significant number of the more than 120 million Americans living in areas that exceeded one or more of the nation's air quality standards in 1988. For the agencies selected, we performed work at each organizational level responsible for establishing, interpreting, and implementing EPA policies for detecting and deterring air pollution violations. Region III was selected because, according to EPA, it contains some of the largest industrial sources in the nation, some of which are located in Pennsylvania. In addition to program size, Pennsylvania was selected because, according to EPA, it has one of the most advanced emission-monitoring programs in the nation. Region IV is EPA's largest region, responsible for overseeing 8 states, 17 local programs, and over 5,400 major stationary sources in 1988. North Carolina, with 1,462 major sources, has the largest single portion of this universe. Region IX was selected to provide west coast geographical coverage and also because

California has a large population potentially exposed to unsafe levels of pollutants.

To address our first objective, we reviewed agency regulations, policies, and selected source files, and interviewed air program officials in EPA headquarters and the above regions, states, and localities to determine the methods available for detecting violations, the successfulness and extent of the use of each, and the benefits and trade-offs of each method. We gave particular emphasis to Pennsylvania's use of emission-monitoring devices because EPA points to this state as having one of the most advanced programs for both detecting and deterring violations using continuous emissions monitors, and to Ohio since this state's CEM program was cited as one of the more comprehensive programs in EPA's 1988 Continuous Emission Monitoring policy. We also gave particular emphasis to EPA's stationary source inspection program because the effectiveness of this surveillance method was questioned in an earlier GAO report,[4] and because this is still the principal method used by EPA, state, and local programs to detect violations. Additionally, we discussed emission-monitoring technology with equipment manufacturers and selected users.

To address whether EPA and the states take appropriate action to ensure compliance at noncomplying major stationary sources, we interviewed EPA headquarters and regional compliance and enforcement program officials, as well as those in the states and localities listed above and obtained documents, where possible, describing their enforcement response policies and practices from January 1986 to the present. We compared and contrasted these policies and practices regarding major sources with Congress' intent in adding enforcement provisions to the 1977 act, and with EPA's national policies for the appropriate, timely resolution of violations. In addition, we judgmentally selected and reviewed enforcement case files with violations identified from January 1, 1986, to December 31, 1987, to illustrate EPA and EPA-approved enforcement policies and practices at work. We also reviewed relevant reports issued by EPA's Office of the Inspector General.

Our work was performed from February 1988 through December 1989. In conducting our work, we reviewed EPA's 1987 and 1988 Federal Managers' Financial Integrity Act reports to the Congress and the President for previously reported internal control weaknesses. Where possible, we

[4]Air Pollution: Environmental Protection Agency's Inspections of Stationary Sources (GAO/RCED-85-1BR, Oct. 24, 1985).

sought to identify the underlying causes of problems we found in EPA's programs for detecting and deterring Clean Air Act violations and the associated management controls that should have prevented these problems from occurring.

The views of EPA officials responsible for overseeing compliance and enforcement activities at major stationary sources were sought during our review and are incorporated into the report where appropriate. However, as requested by the Chairman's office, we did not obtain official agency comments on a draft of this report. Except as noted above, our work was performed in accordance with generally accepted government auditing standards.

Regulations Needed to Require Greater Emission Monitor Use at Major Stationary Sources

EPA compliance officials estimate that continuous emission monitors are 10 times more likely to detect air pollution violations than on-site inspections because they measure emissions directly, provide near-continuous coverage of facility operations, and detect violations which inspectors cannot. Although concerns existed over the reliability and cost of CEMs, their reliability has improved and the costs have become more reasonable. Monitors have been shown to be reliable over 90 percent of the time, and while costs may continue to be a concern for some, the economic burden of CEMs does not appear substantial for many major sources, and some sources may be able to reduce operating costs by using fuel more efficiently.

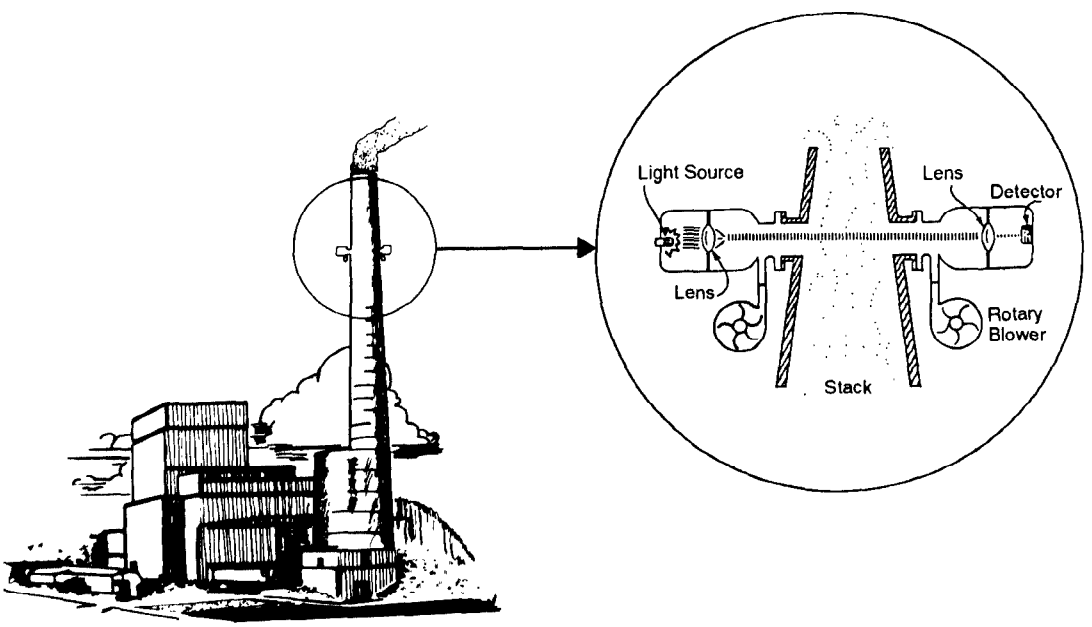
In 1988, recognizing that conditions for CEMs' use had become more favorable, EPA announced a policy encouraging the installation of monitors at any major stationary sources where their use is estimated to be feasible. However, EPA has not issued regulations that (1) establish criteria for determining where CEM use is feasible and (2) require CEM use at sources that meet the feasibility criteria. As a result, monitors have been installed at only 1,065 facilities, or about 11 percent of the 10,000 major sources where EPA estimates that CEMs are feasible, and EPA and states continue to rely primarily on inspections to detect violations.

Recent legislative proposals to amend the Clean Air Act recognize the value of emission monitors and—in an effort to help address the acid rain problem—call for the use of CEMs at about 1,100 of the nation's largest sources of SO_2. However, EPA compliance officials state that they have insufficient resources to develop regulations requiring CEMs at all sources where feasible, and consequently have no plans to require monitors beyond those called for in the proposed legislation.

Detection Capability of Emission Monitors

CEMs are electro-mechanical instruments, usually installed in the facility's exhaust or smoke stacks, which sample, analyze, measure, and record the amount of pollutants passing through the stack. CEMs have been developed to measure various types of pollutants emitted by stationary sources. For example, one type of CEM—opacity monitors—generally operates by measuring the amount of light displaced by visible emissions. This monitor, located in the stack, automatically determines when the amount of displaced light (or opacity) exceeds its permit conditions. Figure 2.1 shows the location and operation of a typical opacity monitor.

Figure 2.1: Location and Operation of a Typical Opacity Monitor



Similarly, other CEMs measure visible and nonvisible pollutants such as SO_2, NO_x, and VOCs by analyzing emission gases several times each hour. Both opacity and gaseous monitors automatically record emission levels.

Detection Potential of Monitors Greater Than Inspections

Senior EPA compliance officials told us that CEMs are 10 times more likely to detect violations than on-site inspections, unless the violations are blatant and ongoing at the time of inspection. Some state officials believe that CEMs are even more effective, with regulators in Pennsylvania—a state which has made substantial use of monitors since 1984—estimating that CEMs may be up to 50 times more effective than on-site inspections. While precise comparisons of the effectiveness of these different detection methods are difficult to make, both groups said that the detection potential of CEMs is much greater than that of inspections because monitors

- measure and record emissions directly and accurately,

- provide near-continuous coverage of facility emissions, and
- detect violations that periodic inspections cannot.

A 1988 EPA study of CEMs at large facilities in Pennsylvania demonstrated that monitors directly measured and recorded accurate opacity readings 98 percent of the time and accurate SO_2 readings over 92 percent of the time.[1] Conversely, in many situations the inspector, using his training and experience, judges a facility's compliance status without empirical evidence of the quantity, rate, or concentration of pollutants emitted. Inspectors often assess facility compliance by visually observing emissions and by reviewing operating equipment, records, and pollution control equipment. Because of the uncertainties involved in making these judgments, inspectors often are unable to determine whether sources are in compliance. For example, in one inspection report we examined, the inspector reported that although visible emissions from a major stationary source appeared to be about 60 to 80 percent opacity—well in excess of the 20-percent permit limit—he "could not do a visible emission evaluation because of the angle of the sun" and therefore no violation was officially recorded.

Unlike inspections, CEMs can operate 24 hours a day and have been shown to measure more than 90 percent of a facility's annual emissions. Inspections often cover less than 1 percent of a facility's annual emissions, usually take 2 to 4 hours to perform and, because inspection resources are limited, are normally conducted at major stationary sources once each year, according to EPA compliance officials. Some facilities may be inspected more frequently if resources allow for it and indications of problems exist. Consequently, facilities are subject to far less coverage when inspections are the only method used to assess compliance.

CEMs can also detect violations that inspectors cannot. According to EPA compliance officials, inspectors have difficulty judging visible emissions at night and in adverse weather, whereas CEMs are not affected by these conditions. More importantly, gaseous emissions, such as SO_2 and NO_x, are generally not visible, whereas CEMs consistently measure these gases directly and reliably. For some gaseous pollutants, inspectors often can only infer compliance by comparing existing process and control system operating conditions with those recorded during stack testing. However, according to EPA, stack test data are collected under finely tuned process

[1] According to EPA criteria, readings are considered acceptable if obtained from a quality-assured CEM that has been calibrated and verified to provide data within 15 percent of the true value.

and control system operating conditions, and thus may be atypical of tests conducted under normal operations, further adding to the difficulty of detecting violations of permit conditions for gaseous pollutants.

We noted an example of these difficulties during our review. Inspectors performing routine inspections at a large fertilizer-manufacturing plant in North Carolina did not detect emissions violations from 1983 until time for permit renewal in November 1986. The State's Technical Services Branch Chief said most inspections during this period had focused on whether the required control equipment was in place, similar to their inspection practices at other facilities. At permit renewal, inspectors discovered that the facility had altered the pollution control equipment years earlier by removing the materials inside the facility's scrubbers. According to state officials, these materials were integral to the proper functioning of the control devices, and their removal allowed untold amounts of SO_2 and fluoride to be released into the atmosphere. EPA's Region IV field inspector responsible for covering North Carolina told us that, had CEMs been installed in this case, many of the emission violations would have been detected earlier and, with prompt enforcement action, the environmental harm lessened.

Not Enough Emission Monitors in Use

Senior EPA compliance officials told us in October 1989 that only about 1,065 major stationary sources had CEMs installed, even though they estimated that CEMs were feasible at about 10,000 sources. These officials' estimate of 10,000 facilities is based on their knowledge of the categories, types, and sizes of facilities that constitute the universe of 33,500 of the nation's largest stationary sources. Ten thousand is the number of sources where, in their opinion, one or more CEMs would be technologically feasible and economically viable for use in detecting violations. Although no specific criteria have been developed translating these concepts for monitor use into further action, according to the National CEM Coordinator, this means that a facility is capable of installing and maintaining a CEM that provides reliable data at a cost that would not be an economic burden to the firm. EPA had not developed more specific criteria delineating the potential for major stationary sources to use monitors at the time of our audit.

EPA also lacks precise data on the number of major stationary sources with CEMs, but based its 1989 estimate of 1,065 facilities with one or more monitors installed on its 1989 workload model, contacts with EPA regional and state CEM coordinators, and EPA-sponsored studies of CEM use. According to the National CEM Coordinator, little has changed since

the findings of a 1988 EPA study that reported that few monitors were in use relative to the potential for their widespread use. The report stated that only 5 states had more than 100 CEMs installed within their jurisdictions, and 26 states had 25 or less CEMs installed. According to EPA officials, facilities often have more than one device at the same facility. Additionally, EPA reported in August 1988 that many installed CEMs were not used to detect violations, and that only 16 states had used CEMs to detect violations. Instead, data from monitors were often used only to target sites for inspections.

Extent of Noncompliance Understated

Because EPA and state regulators continue to depend largely on on-site inspections to detect violations at nearly 95 percent of the major stationary sources, senior EPA compliance program managers believe the extent of noncompliance among major stationary sources may be significantly understated. In this regard, EPA's Stationary Source Compliance Strategy states that, because of the limitations inherent in on-site inspections,

> it is fair to assume that compliance data being reported by States do not indicate what is happening at a facility on a day-to-day basis, but rather whether the source has been determined to be in compliance at an announced inspection after it has had the opportunity to optimize the performance of its control equipment. Thus, it indicates whether the source is capable of being in compliance rather than whether it is in compliance in its day-to-day operations.

Similarly, a September 1987 EPA Region IV memorandum points out that EPA's practice of relying on opacity observations and on-site inspection of the source does not ensure that the source is in compliance at all times. The memorandum further states that EPA's practice is "hit or miss."

Even with the limited detection potential of on-site inspections, about 14 percent of the major stationary sources were detected violating permit or other requirements in fiscal year 1988, with 1,404, or about 30 percent, of these noncomplying sources in violation one or more times each month for every month of the fiscal year, according to EPA data.

Concerns Regarding Monitor Reliability and Cost

Industry and regulatory officials have expressed concerns about the reliability and cost of CEMs. According to EPA's Stationary Source Compliance Division Deputy Director, monitor reliability has improved substantially and the costs are more reasonable than they were in 1975, when EPA issued its first SIP emission-monitoring regulations. While these concerns may have been legitimate in the past, the issues of reliability and cost, according to EPA's 1984 National Compliance and Enforcement Strategies, have been replaced to some extent with misinformation and inertia. For example, in Pennsylvania—a state which has made increasing use of CEMs since 1984—emission monitors were required at nearly 200 sources as of May 1988. The Chief of Pennsylvania's Division of Abatement and Compliance, Bureau of Air Quality Control, said that using CEMs is largely a matter of mind-set, and that Pennsylvania had decided several years ago that a properly implemented CEM program could produce accurate, reliable data at a cost that was not burdensome to industry. More importantly, he said that, where they can be used, emission monitors are the most effective method of detecting violations and reducing emissions. The Director of Pennsylvania's Bureau of Air Quality Control said that, while CEMs are not appropriate for every major stationary source, the state's experience had been so positive that Pennsylvania will require seven CEMs on each municipal waste incinerator it permits in the future. On average, Pennsylvania CEMs have collected reliable data over 90 percent of the time.

With respect to cost, EPA compliance officials recognize that cost may continue to be a concern at some sources where EPA envisions using CEMs to detect violations, but these officials said that in relation to facility size and gross annual revenues, the cost of monitors is justified, in their opinion, at about 10,000 of the 33,500 major stationary sources. In their opinion, installing and operating CEMs would not constitute an economic burden for these major stationary sources. Further, EPA points out that using CEMs to detect violations is already an important part of a few state programs. For example, California and Pennsylvania officials have used CEM readings to not only detect violations but also to take enforcement actions at a number of sources within their jurisdictions. For example, of the 4,076 total violations cited in the San Francisco Bay Area in 1986 and 1987, 216 were based on CEM readings, while Pennsylvania issued 260 violations on the basis of CEM readings for a similar 2-year period, eventually settling the cases for $336,600 in penalties.

Because most state and local agencies have been slow to implement a CEM regulatory program, EPA sponsored several studies in an attempt to foster their wider acceptance and use in detecting violations. According

to a June 1986 report,[2] state agencies' reluctance to implement an emission-monitoring program centers around (1) perceptions of CEMs as unreliable and (2) concerns that their use would place additional burdens on the limited resources of regulators. The report stated that the perception of state managers was that EPA had required the states to proceed with a questionable monitoring program, without adequate state agency consultation, and then had not provided sufficient technical and policy support to make the program work.

After pilot testing CEMs in two states for more than a year, the study concluded that CEMs' performance showed "very high levels of reliability," and the burden of reviewing excess emission reports was not a burden, averaging less than 1 hour per report. Most importantly, the study demonstrated that CEMs were a highly effective method for assessing the compliance of selected facilities, and that the issue of unreliability can be readily resolved by a management commitment to quality assurance.

Cost Implications of Emission Monitors

While an effective quality assurance program can overcome concerns about the reliability of CEMs, resolving the issue of cost has not been as easy for EPA. First, because installing, operating, and quality assuring data from CEMs' is an expense that facility owners and operators must absorb, EPA does not envision their use at all sources; instead, EPA has targeted only the newest and largest of the major stationary sources. According to EPA compliance officials, the costs of installation vary greatly, from about $10,000 to $150,000, depending on the type, size, location, and facility design, as well as whether any retrofitting is involved. Annual operating and maintenance costs, including quality assurance and periodic reporting, range from about $5,000 to $50,000. However, EPA's National CEM Coordinator points out that relative to the cost of other pollution control equipment that major stationary sources must install, these costs are small, reasonable, and justified, in his opinion, at many major stationary sources.

To help alleviate industry concern over the issue of cost, EPA conducted reviews of selected facilities. As a result, EPA reported in a December 1988 Federal Register that CEMs constituted less than 4 percent of total air pollution costs. Further, as reported by the 1988 Joint Power Generation Conference, in some cases CEMs can reduce operating expenses.

[2]Summary Report: A Pilot Project to Demonstrate the Feasibility of a State Continuous Emission Monitoring System (CEMS) Regulatory Program (EPA, June 1986).

According to the Deputy Director, Stationary Source Compliance Division, the relative cost of installing CEMs at major sources is less than the cost of installing a speedometer on an automobile. He pointed out that while using CEMs to detect violations may not result in significant savings in inspection resources, it is the most effective means of ensuring facility compliance with permit conditions. According to the National CEM Coordinator, in addition to unreliability, industry has used cost as a reason for resisting CEMs when cost is not the reason. The real reason, in his opinion, is that facilities simply do not want their emissions monitored on a full-time basis. CEMs can tell exactly when a source exceeds its permit limits, by how long and how much, he said. He bases his opinion on his dealings with industry, EPA regional and state CEM coordinators, and EPA's own studies. For example, in response to one facility's high cost estimates for CEMs, an in-depth investigation by EPA found that the facility's annual costs would be increased less than two-tenths of 1 percent.

Our work similarly indicates that cost may not be a principal reason that more sources have not installed CEMs. For example, we visited a major coal-fired utility that had installed two opacity and two SO_2 monitors at a total cost of about $250,000, according to the Assistant Plant Manager. To place this amount in perspective, he said gross revenues of this facility average over $100 million per year through the sale of electric power to sections of the northeastern United States. Company representatives told us that CEMs allow them to more closely monitor fuel combustion efficiency and to better ensure the quality of low-sulfur coal from suppliers. Although they had not evaluated whether CEMs had actually reduced operating expenses, the representatives said that the costs were not unreasonable.

Other firms we contacted said that they had reduced their operating expenses by using CEMs. For example, a major manufacturer of wall coverings in Ohio reportedly saves about $50,000 annually in fuel costs because its SO_2 monitors more closely gauge fuel combustion efficiency, and a large U.S. automobile manufacturer, which also operates its own power generating facilities, similarly saves at least $12,000 annually in fuel costs at each of its industrial boilers from CEMs it uses.

Operational cost savings have also resulted from using CEMs at sources other than large power-generating facilities. Although EPA has promulgated no regulations on the use of VOC monitors, savings have been estimated for several Pennsylvania facilities using VOC monitors. For example, one inspector reported that one manufacturer reduced its

annual costs for solvent by $50,000 after equipping its carbon absorption unit with VOC monitors and changing its operating practices accordingly. Solvent recovery for this firm increased from 68 percent in June 1988 to 87 percent in September 1988 after installing CEMs to detect excess emissions. Another Pennsylvania facility's solvent usage was nearly cut in half after installing VOC monitors and correcting inefficient operating techniques. According to a 1988 inspection report, this firm decreased its solvent usage by 45 percent, representing an annual reduction in operating expenses of about $20,000.

Monitors Believed Feasible at More Sources

EPA, state, and industry officials told us that CEMs are technologically feasible and economically viable, or capable of providing reliable emissions data at a cost that would not be an economic burden to the source, at many more sources than those that currently use them. For example, the Coordinator of Ohio's CEM program said steam generators as small as 10 million Btus in size have been required to install and operate CEMs to monitor SO_2 emissions in Ohio, whereas EPA's regulations require CEMs only on steam generators that are larger than 250 million Btus. A Ford Motor Company Regional Environmental Engineer agreed, noting that Ford has used CEMs extensively since 1981 because the company found that CEMs help Ford reduce operating costs. He said they are even used on power boilers not covered by Ohio's CEM requirements. Furthermore, California and Pennsylvania local air compliance program officials told us that in selected cases, VOC monitors are feasible and already used in their states to detect violations, even though EPA has no regulations requiring VOC monitors at any major sources. Pennsylvania officials told us they also plan to use CEMs on hazardous, municipal, and infectious waste incinerators.

Other indicators also support the position that CEMs are potentially feasible for many more sources than currently use them. For example, according to the National CEM Coordinator, EPA has an effort underway to improve its emission-monitoring data base for SO_2 monitors at major power-generating facilities as part of EPA's increased emphasis on acid rain. Airborne SO_2 is a major component of acid rain. Data from this effort indicate that, as of January 1988, only 365 of 2,414 major SO_2 sources in the United States used SO_2 monitors. According to EPA's National CEM Coordinator, CEMs are economically feasible at nearly all of these facilities.

EPA Regulations Focus on Newest and Biggest Sources

Sections 110, 111, and 114 of the Clean Air Act collectively provide EPA with the authority to require any stationary source to install, use, and maintain emission-monitoring equipment. Under this authority, EPA has issued regulations requiring CEMs to be installed at 23 categories of new sources and 4 categories of existing major stationary sources. However, because of the reliability and cost concerns discussed above, EPA's regulations governing the use of CEMs have largely targeted only the newest and biggest sources, and have allowed even these sources alternatives and exceptions to the use of CEMs, according to EPA compliance officials. For example, in August 1988 EPA reported that only 35 sources could be categorized as electric utility steam generators of greater than 250 million Btu-per-hour capacity that had begun construction after September 18, 1978—one of the New Source Performance Standard (NSPS)[3] categories required to install CEMs under section 111 of the act. Similarly, under another subpart of the new source regulations, only those industries that began construction of large steam generators (greater than 100 million Btus per hour capacity) after June 19, 1984, are to install CEMs.

The number of CEMs EPA requires under other sections of the act is similar to its new source requirements, targeting only the biggest of sources. Under section 110 of the act, EPA is to ensure that state and local programs' SIPs require certain existing facilities to monitor emissions. Although states are free to target additional sources, EPA has designated only four narrowly defined categories of existing sources subject to these requirements. These categories include (1) fossil fuel-fired steam generators with a rated capacity of greater than 250 million Btus per hour, (2) nitric acid plants with production capacity of more than 300 tons of nitric acid per day and which are also located in nonattainment areas for NO_x, (3) sulfuric acid plants with production capacity of more than 300 tons of sulfuric acid per day, and (4) fluid bed catalytic cracking units at petroleum refineries with production capacity of more than 20,000 barrels per day.

[3]Major stationary sources constructed after specific dates identified in EPA's regulations are subject to NSPS standards, which generally require installation and use of more stringent controls to attain lower emission levels and, in the case of selected NSPS sources, continuous monitoring of emissions.

EPA's Monitor Use Policy Not Implemented

Efforts to ensure that major stationary sources maintain compliance have become increasingly important, according to EPA, now that most facilities have installed the basic pollution control equipment. In recognition of this growing need and because monitor reliability has improved and, according to EPA, the costs are more reasonable, in March 1988 EPA's Office of Air Quality Planning and Standards issued an emission-monitoring policy calling for CEM installation and use where feasible. According to the policy, if it is technically feasible, CEMs should be required in all new facility permits, operating permits, and resolutions of enforcement actions, including consent decrees and administrative orders. The policy states that CEMs should be used to ensure continuous compliance of sources in both attainment and nonattainment areas. The policy also points out that at least five states—Indiana, Ohio, Pennsylvania, Tennessee, and Washington—already have well-developed emission-monitoring programs, and that EPA's review of these programs has shown CEMs to be valuable tools for ensuring compliance. EPA states in its policy that it is committed to using CEM data in assessing facility compliance.

However, EPA has not fully followed through in implementing its policy, citing resource limitations and higher priority activities. For example, EPA's Stationary Source Compliance Division Deputy Director pointed out that funding for compliance activities has declined 35 percent (in noninflationary adjusted dollars) since 1979, while the major stationary source population has grown from about 23,000 to over 30,000 sources in the same time period. Although EPA's air program work force has remained about the same size nationally, compliance program staffing has been reduced by 14 percent, from 339 to 293 staff, since 1980. He also pointed out that, while these reductions were taking place, even minimally acceptable inspections have become more complex and time-consuming, often taking 50 percent more time than previously required. In addition, efforts expended on a host of new problems such as asbestos, air toxics, radon, hazardous and municipal waste incineration, and smaller sources of VOCs have taken ever increasing amounts of inspectors' time.

Thus, while EPA has the authority to require CEMs at a broad range of sources, according to the Deputy Director, the Stationary Source Compliance Division's limited available resources have forced headquarters managers to make difficult choices, effectively making EPA efforts to require more extensive use of CEMs a lower priority. The National CEM Coordinator explained that, in order to issue regulations requiring CEMs at a broad range of sources, the Stationary Source Compliance Division

would need to validate the various measurement methods involved, develop quality control and quality assurance methods and manuals, develop and propose regulations for each industry affected, answer and incorporate comments on the proposed regulations, and then promulgate final regulations. The Deputy Director explained that undertaking these activities is not possible with their current staffing if they are to also continue compliance and enforcement actions at sources and address new and emerging environmental issues. Consistent with the Deputy Director's statements, EPA's 1984 Compliance Monitoring Strategy for Major Stationary Sources points out that without additional resources, EPA's air compliance program cannot address both the need for CEMs and the need to capture previously unregulated smaller sources of harmful pollutants such as VOCs, or to effectively control asbestos demolition and renovation projects. EPA decided the latter was a higher priority need.

While resources and work load are legitimate factors, EPA continues to approve and fund state and local inspection programs that make little use of CEMs. In 1988, EPA, and state and local agencies conducted over 37,000 inspections. Furthermore, EPA has been slow to ensure that state and local programs comply with the Agency's 1975 regulation requiring them to incorporate CEM provisions in any SIP revisions after that date. For example, two states in EPA Region III—Maryland and West Virginia—have had SIPs approved without CEM provisions because CEMs have not been a high priority consistently over the years, according to EPA Region III officials. EPA Region IV officials explained that inconsistent guidance and direction from EPA headquarters over the years regarding the need for adequate CEM provisions in state SIPs had also caused them to question the Agency's commitment to CEMs as a detection method. Consequently, they told us in June 1988 that their regional approach to CEMs had largely been one of assistance rather than leadership. They explained that if a state or local agency solicited their help in establishing an active CEM program, they would work with them in doing so. Otherwise, it was not a priority.

In addition, headquarters officials told us that EPA has not developed a strategy for promoting CEMs at more facilities, nor do they have a plan for validating existing CEM technology and measurement methods—two critical first steps to regulatory use of CEM data in enforcing emission limits. Furthermore, in both 1988 and 1989, EPA reduced funding for its CEM program, according to the National CEM Coordinator. Even an EPA-

contracted study found that lack of management support and commitment to the CEM program has seriously hampered its implementation. Specific problems identified in this 1988 report[4] included the

> lack of or inconsistent responses to Regional initiatives and inquiries, failure to provide training and in-house technical support, and failure to resolve important data quality problems for the CDS/CEMS subset. Recent EPA policies and program priorities have in some cases been inconsistent with continued support of CEMS program implementation. In a least one Region, a decision to discontinue CEMS-related efforts was reportedly made in response to comments from a visiting OAQPS [Office of Air Quality Planning and Standards] Headquarters representative that the Agency was moving away from the NSPS program.

Clean Air Act Amendments Recognize Value of CEMs

In an effort to control acid rain, the administration's proposed amendments to the Clean Air Act recognize the value of CEMs and would require their use by the most significant contributors to the nation's acid rain problems. More specifically, under Senate Bill S.1630, opacity, SO_2, NO_x, and volumetric flow monitors would be required at 111 of the nation's largest coal-fired electric utilities within 36 months of enactment, and at another 800 to 1,000 of the nation's largest major industrial sources within 5 years of enactment, according to EPA. While these proposals are a step in the right direction, they include some facilities that already have monitors installed and stop short of legislating the extensive use of CEMs already called for in existing EPA policy. According to senior EPA compliance officials, CEMs are technologically feasible and economically viable at an estimated 10,000 major stationary sources and could enhance the likelihood of detecting violations at these sources substantially over current practices.

Despite the significant detection potential of CEMs, because of cited resource limitations, EPA officials said that they will continue to rely primarily on their encouragement of state and local agencies to develop CEM programs, but will not be able to require their broader use under federal regulations. According to senior compliance program managers, while EPA has the authority to require broader use of CEMs, their installation and use beyond the sources already identified in the proposed legislation will continue to be slow.

Conclusions

Major stationary sources are one of the biggest contributors to our nation's air pollution problems. These facilities are responsible for

[4]Status of EPA Regional CEMS Program Implementation (EPA, Aug. 1988).

nearly 40 percent of the nation's total emissions of criteria pollutants. EPA has sought, through regulations, permit requirements, and its review and approval of SIPs, to control major stationary source emissions. However, ensuring compliance at major sources has been, and continues to be, a significant problem.

CEMs represent a significant improvement in ensuring that major sources comply with emission requirements. The concerns about CEMs that existed in the past—reliability and cost—have been eliminated or reduced and, in our opinion, do not remain an impediment to their widespread installation and use. Further, in contrast to traditional inspections, the use of monitors provides solid evidence of a facility's emission levels and whether it complies with permit conditions. CEMs provide far more coverage of facility operations than do inspections and can detect violations that inspectors cannot.

EPA's efforts to expand the use of CEMs at existing stationary sources, however, have been inadequate. Although EPA's policy for encouraging the use of CEMs is a strong acknowledgement of the benefits of this technology, installation of this equipment will not occur on a widespread basis until it is required by EPA. This is because once CEMs are installed, major sources that are not operating within their permit limits face a much greater likelihood of detection. However, the regulations needed to transfer this policy into requirements have not been forthcoming. In our view, regulations that (1) establish criteria for determining where CEMs are technologically and economically feasible and (2) require CEM use in all situations where these criteria are met would significantly increase the use of this technology.

The proposed Clean Air Act Amendments would increase the number of facilities required to install and use CEMs. The amendments, if enacted, would mandate the use of monitors at approximately 1,100 facilities. However, on the basis of EPA's estimate that CEMs are feasible at about 10,000 facilities, considerably greater use can and should be made of CEMs in light of the continued air pollution problems.

Recommendation

In order to more effectively implement EPA's emission-monitoring policy and achieve more widespread monitor use, we recommend that the Administrator, EPA, promulgate regulations that (1) establish clear criteria for determining where CEMs are feasible for major stationary sources and (2) require CEM installation and use at all major sources meeting these criteria.

Penalty Amounts Not Sufficient to Deter Violations

Failure to comply with emission requirements can result not only in additional air pollution, but can also be of economic benefit to major stationary sources. To deter such noncompliance, the Clean Air Act contains penalty authority that allows enforcement officials to administratively assess noncompliance penalties sufficient to remove any economic benefit a violator can gain from failing to comply with the act's requirements. EPA has also established a civil penalty settlement policy used in its civil litigations that requires agency attorneys to accept only those settlement offers that are calculated to offset the economic benefit violators obtain through noncompliance.

State and local programs, however, which handled over 80 percent of the enforcement actions in fiscal year 1989, have not been required to seek economic benefit penalties. These state enforcement programs operate under state law as embodied in the various SIPs, not under the administrative penalty provisions embodied in the Clean Air Act or the EPA civil penalty settlement policy, and EPA has not insisted through the SIP approval process that states commit themselves to imposing economic benefit penalties. As a result, penalties imposed on significant violators—EPA's highest enforcement priority—were often not sufficient to remove the economic benefit of noncompliance. Specifically,

- fewer than half of the significant violators in fiscal years 1988 and 1989 paid cash penalties and
- when cash penalties were assessed, the penalties often were not based on the violator's economic benefit.

Further, although EPA can seek to impose its own penalties in those instances where state and local penalties are inadequate, it has seldom acted to collect additional moneys because it views its own enforcement process as cumbersome and too resource-intensive.

To help EPA take enforcement actions more efficiently, proposed amendments to the Clean Air Act contain provisions that grant EPA additional administrative penalty authority for enforcing air pollution violations. However, EPA still needs to clarify its authority over state and local agencies' enforcement actions to ensure that fair and equitable penalties are consistently imposed, including taking action in state and local cases where penalties are not sufficient. Otherwise, sources that comply will continue to be at an economic disadvantage to those that do not.

Economic Benefit Penalties Established to Promote Compliance

Failure to comply with emission requirements can result in significant economic benefit to major stationary sources. Among other things, these facilities can reap dollar savings by (1) not purchasing pollution control equipment or maintaining equipment already in use, (2) using less expensive but higher polluting raw materials, (3) not changing their production processes, or (4) not applying for a permit to conduct operations controlled under the Clean Air Act. For example, according to a 1986 industry study of emission control technology, steel drum manufacturers and reconditioners could save from $240,000 to $530,000 per plant in annualized costs by not purchasing the equipment needed to control VOC emissions.

To address such financial disincentives to compliance, the 1977 Amendments to the Clean Air Act gave EPA administrative authority to impose substantial cash penalties for pollution control violations. Section 120 of the act provided EPA with administrative authority to make a finding of noncompliance and assess cash penalties against noncomplying firms sufficient to remove any economic benefit derived from the violation. The intent of this provision was to forestall noncompliance with the act's requirements by removing the economic advantage to be gained by postponing investment in pollution control. At the same time, the Congress increased the civil penalties that can be imposed under section 113 of the act and expressed an intent that court-imposed civil penalties "be assessed in amounts which are adequate to assure compliance will result, rather than permitting continued noncompliance to be economically profitable."

EPA established regulations for imposing economic benefit penalties that are consistent with the intent of section 120. In 1984, EPA also developed the Clean Air Act Stationary Source Civil Penalty Policy which requires, among other things, that when EPA settles an enforcement lawsuit out of court, all such EPA settlements seek to remove the economic benefit derived by not complying with the act's requirements.[1] This civil penalty settlement policy provides that, except in extraordinary circumstances, "the lowest possible settlement penalty will be the calculated economic benefit of noncompliance." The policy directs that delayed and/or avoided expenses, such as the costs of control and monitoring equipment, modifications to production processes, operation and maintenance, and the employment and training of pollution control personnel,

[1]The EPA policy does not restrict the decision a judge might render if a particular case should go to trial, and the economic benefit that may be calculated is subject to the statutory maximum of $25,000 per day of violation.

be included in the calculation of economic benefit. Furthermore, the civil penalty settlement policy provides that additional amounts be obtained, if warranted, to reflect the gravity or seriousness of the violation.

Economic Benefit Penalties Not Imposed by State and Local Programs

Because the act is structured as a federal/state partnership for the control of air pollution, state and local agencies are authorized to carry out enforcement activities against violators, including major stationary source violators. In fiscal year 1989, state and local agencies handled over 80 percent of the enforcement actions against stationary sources. These activities are required to be performed in accordance with EPA-approved SIPs, which establish the requirements that authorized state and local programs must adhere to in order to avoid the act's sanctions and obtain federal funding.

However, EPA has not required authorized state and local programs to calculate or impose economic benefit penalties to correct violations. The last major revisions to SIPs were in 1982—about 2 years before EPA finalized its Stationary Source Civil Penalty Policy. Although EPA has the authority to call for unscheduled SIP revisions whenever it is apparent that attainment is in jeopardy, and although individual SIPs have been acted upon during the intervening years, EPA has not required state and local officials to revise their SIPs to upgrade administrative penalty provisions to recover economic benefit. As a result, state and local programs often do not impose cash penalties and at other times impose penalties that do not remove the economic benefit of noncompliance. EPA data for fiscal years 1988 and 1989 show that over half of the significant violators—54 percent—identified by state and local programs paid no cash penalties. Table 3.1 summarizes the penalties assessed in state and local enforcement actions in these years.

Table 3.1: Resolution of State and Local Enforcement Actions for Significant Violator Cases, Fiscal Years 1988 and 1989

	1988 cases		1989 cases		Total cases	
Type of resolution	**Number**	**Percent**	**Number**	**Percent**	**Number**	**Percent**
Cases resolved with cash penalty assessed	183	37	336	53	519	46
Cases resolved with no cash penalty assessed	315	63	300	47	615	54
Total cases resolved	**498**	**100**	**636**	**100**	**1,134**	**100**

Our review of eight state and local programs found that none regularly sought to recover economic benefit penalties. Three of the eight programs used EPA's civil penalty settlement policy occasionally as a reference in assessing but not collecting fines, four programs did not consider economic benefits in imposing cash penalties, and one program—Arizona's—did not have the authority to enforce civil penalties against violators, according to Arizona Office of Air Quality officials. In order to assess monetary penalties for violations in Arizona, criminal charges must be brought by the state attorney general's office, and the case must be tried in criminal court. Otherwise, the state program can only issue violation notices, which carry no monetary penalties.

Our review of enforcement actions in the eight programs included cases that were resolved without penalties to remove the economic benefit of noncompliance. As shown in the following three examples, although the severity of the violations varied, violations that appear to have economically benefitted the violator were settled with either no cash penalty assessed or, when cash penalties were imposed, no economic benefit calculated:

- A North Carolina facility emitting particulates[2] and VOCs from the annual production of about 30,000 tons of pipe (1) violated its permit limits for particulate emissions 5 times between 1984 and 1988, with 1 inspection observing opacity emissions at nearly 100 percent—almost 5 times above its limit of 20 percent, (2) conducted pipe grinding and fitting operations without a permit, and (3) used noncompliant paint coatings that exceeded VOC emission levels by 13 percent. Local program officials acknowledged that the firm may have benefitted financially from the avoided and delayed cost of timely compliance, but the economic benefit was not calculated by the local agency and no penalty was assessed. According to the manager of the local agency's Air Quality Branch, the firm agreed in July 1988—nearly 5 years after problems were first discovered—to do a better job of operating and maintaining its control equipment, not operate any new processes without a permit, and have its paint reformulated to meet the standard.
- A major refinery located in an ozone nonattainment area in California was cited for 10 violations of VOC emissions standards in 1986 and 1987, resulting from defective tank seals, failure to use proper seals, and leaking valves. At the time of our review, three of the violations were resolved with no cash penalty and four were resolved for a total penalty of $1,300. The remaining three violations were still unresolved at the

[2]Particulates include dust, dirt, soot, smoke, and liquid droplets emitted into the air.

time of our review. No calculation of economic benefit was performed, although enforcement records show that the violations resulted from preventable operational failures and were not the result of equipment breakdown or malfunction.

- A major drum-reconditioning facility in North Carolina, producing about 900 reconditioned steel drums daily, emitted excess VOCs into a VOC nonattainment area from 1980 to 1986 in violation of EPA regulations. This facility failed to install required control equipment by July 1980 and, when discovered in 1986, was using paints that emitted VOCs 57 percent above the standard set for coating steel drums. Negotiations with the facility to resolve the violations took over 2 years, resulting in a penalty of $15,000. No calculation of economic benefit was performed, but the local air program director told us that this penalty amount was consistent with historical amounts for other violations in the local area.

These penalties, however, may not approach the benefit the violator obtained nor serve as a deterrent to future violations. At our request, the EPA headquarters official responsible for the economic benefit program calculated the estimated economic benefit for the violation at the drum-reconditioning facility discussed above. According to his estimate, the economic benefit the firm derived was over $231,000—about 15 times larger than the $15,000 fine imposed. Furthermore, in this situation, the size of the penalty may not have deterred future violations. During a June 1988 inspection—2 months after paying the $15,000 penalty—this facility was found conducting unpermitted operations and had noncompliant materials on-site that would emit excess VOC emissions.

EPA's Office of the Inspector General has also found that penalties are insufficient. In a March 1988 report on EPA Region V and the states of Michigan and Wisconsin, the Inspector General reported that penalties are largely based on what EPA and state regulators believe they can obtain from the company rather than the economic benefit. The report further stated that most collected penalties did not recover the savings the violator received from delayed and/or avoided costs and that cases were found with no support as to how the penalty was calculated.

State and Local Enforcement Philosophies Differ From EPA's

State and local agencies generally seek to use their enforcement actions to secure a source's future cooperation rather than to penalize past violations. Some officials from state and local programs we contacted told us that their penalties are often directed toward getting the attention of

the violating facility's management, including threats of adverse publicity, rather than removing the economic benefit of noncompliance. They said their programs attempt to achieve compliance by working cooperatively with facility owners and operators to correct the cause of the violation, in lieu of assessing penalties. For example, the Chief of North Carolina's Air Quality Section said that their approach does not include calculating, assessing, or collecting penalties using economic benefit as the means of deterrence.

Similarly, one local program official said that compliance, rather than penalizing violators to remove the economic benefit of noncompliance, is the goal of his program. His goal is compliance through field presence and technical assistance to those firms having pollution control problems. He also said that other concerns must be considered in imposing penalties for violations, one of which is the financial impact of the penalty on the violating facilities. He expressed concern that placing economic benefit penalties on significant violators could put facilities in his area at a competitive disadvantage relative to facilities in other areas that do not impose such penalties.

According to some state and local officials, penalties need only be large enough to get the attention of facility management. As a result, they said their enforcement philosophies will continue to emphasize compliance through field presence, technical assistance, and fines on a case-by-case basis.

EPA Has Made Little Effort to Increase Penalties

EPA could increase cash penalties if, through its review and approval of SIPs, it were to require state and local enforcement agencies to adopt penalty policies similar to the section 120 regulations and, in situations where the state and local agencies do not obtain economic benefit penalties, by initiating its own action to impose a penalty. However, EPA has been reluctant to specify that state and local programs seek economic benefit penalties because the Agency is uncertain of its authority to do so. Further, EPA's ability to otherwise influence state and local programs' penalties is viewed as limited because of the time, expense, and resources required to initiate its own enforcement actions.

EPA Reluctant to Require Programs to Adhere to Penalty Policy

EPA officials said that they have been reluctant to mandate that authorized programs commit themselves to imposing economic benefit penalties. According to these officials, requiring programs to follow EPA's civil penalty settlement policy on recovering economic benefit could be

viewed as an infringement on the states' authority to operate their own programs. This could result in the states giving programs back to the federal government to operate rather than complying with enforcement standards based on EPA's economic benefit regulations and the related civil penalty settlement policy. EPA compliance officials pointed out that in 1984, EPA attempted to get state and local programs to adopt EPA's policy, but terminated this effort in 1985 after failing to reach consensus with the State and Territorial Air Pollution Program Administrators and the Association of Local Air Pollution Control Officials—associations which represent state and local air pollution control officials. Since 1985, EPA has not attempted any similar efforts.

EPA compliance officials also said they are unsure of the Agency's authority to require authorized programs to upgrade their penalty policies. They pointed out that state and local programs implement state laws. Consequently, for state and local programs to be required to impose economic benefit penalties, state laws would have to be amended, and the EPA officials were uncertain of their authority to require this. EPA's earlier attempt led them to believe that states would not be willing to amend their laws to conform to a more stringent penalty policy unless such conformance was specifically required as part of the act.

We found that EPA has not requested a legal ruling from EPA's Office of General Counsel on this matter. EPA compliance officials said that such a request could further impinge on their already deteriorating relationship with many state and local programs and that a negative ruling from EPA's own counsel could place them in a worse position for interceding in problem cases than current practice allows.

In our view, however, EPA has the authority to require that SIPs be revised to incorporate whatever enforcement procedures EPA deems adequate, including the nondiscretionary imposition of economic benefit penalties for violations. Specifically, section 110 of the act sets out the minimum requirements for the content of a SIP and charges EPA with SIP review and approval. According to this section, a SIP must include a program to provide for the enforcement of emission limitations and necessary assurances that the state will have adequate authority to carry out the SIP. Additionally, section 172 of the act, which deals with nonattainment areas, mandates that EPA ensure that SIPs include all the necessary requirements to achieve and enforce compliance with the plan.

Concerns such as those that EPA officials expressed have been raised before in the context of vehicle inspection and maintenance programs. Although these programs were a source of much contention, the courts ultimately held that states could be required to enact legislation to carry out the Clean Air Act's requirement to develop such programs or accept the sanctions provided under the act. Under the same theory, a state could be required to seek and collect economic benefit penalties for emissions, permit, and other violations by stationary sources.

EPA Ability to Impose Additional Penalties Has Been Limited

EPA is authorized to initiate a civil suit under section 113 of the act or an administrative action under section 120 to increase state penalties. EPA refers to this procedure as "overfiling." Although sections 113 and 120 provide EPA with the legal authority to issue orders, commence civil actions, institute criminal proceedings, and assess economic benefit penalties, EPA compliance officials said their ability to remedy insufficient state and local penalties is limited because each of these sections currently has drawbacks that hamper EPA from ensuring that state and local penalties are adequate.

In addition to other sanctions, section 113 authorizes EPA to seek court-imposed penalties for air pollution violations. However, EPA compliance officials contend that this is an expensive, time-consuming process, sometimes costing more to prosecute than the eventual court-imposed penalty. According to EPA's Assistant Enforcement Counsel for Air Enforcement and Compliance Monitoring, undertaking court action can cost EPA from $50,000 to about $400,000 on civil actions it takes against polluters, depending upon the complexity of the case and whether the case actually goes to trial or is settled before a trial begins. He stressed that EPA has no way of knowing which cases will actually go to court, so all cases must be handled as if they will eventually end up before a judge. Although overfiling, if successful, can have significant deterrent effects, the high cost of using section 113 to overfile in large numbers of cases where penalties are insufficient is impractical, according to the Assistant Enforcement Counsel. The Chief of EPA's Region IV Air Compliance Branch concurred, noting that in some cases, EPA collects less penalty money from overfiling in state and local cases than it spends in taking the enforcement action. EPA cannot recoup its costs of litigation, and all penalty money collected goes to the U.S. Treasury, not to EPA.

In contrast to section 113, section 120 authorizes EPA to assess economic benefit penalties administratively and to avoid court action unless a source appeals EPA's administratively determined sanction. However,

EPA views this provision of the act as having other problems which make it undesirable to use in many cases. For example, section 120 does not provide EPA with the ability to collect a penalty for any period of violation that occurs before EPA has officially notified the owner or operator of the noncompliance, a limitation not found in section 113. Additionally, the penalty calculation formula for section 120 was promulgated in EPA regulations and requires collection of the full economic benefit, providing little flexibility, according to EPA, for regulators to settle cases for less. Also, section 120 seeks to gain compliance through economic penalties alone and provides no ability to order compliance or to seek injunctive relief. Although the act allows EPA to use section 113 and 120 together to achieve an appropriate remedy for a violation, EPA officials said dual actions such as this are an extremely costly way to achieve compliance, and thus such dual actions are officially discouraged by EPA's enforcement program guidance.

Because of the high cost, difficulty, and inflexibility of using their current authorities to increase state and local penalties, EPA overfiles relatively infrequently. According to the Deputy Director, Stationary Source Compliance Division, the air compliance program's enforcement resources are limited, and any EPA region is able to sustain case work on only 12 to 15 enforcement actions a year, or a total of 120 to 150 cases a year nationwide. Consequently, EPA headquarters and regional officials told us they are able to overfile only in precedent-setting cases and those where the initial penalties are grossly deficient. Region IV staff told us that because so many penalties are deficient, a regional rule of thumb—described in a March 1988 EPA Office of the Inspector General report on Region IV as the "laugh test"—is used to determine which cases will be challenged. According to Region IV staff, a proposed penalty is not challenged if they do not laugh too loudly. A Region III enforcement official told us that, while other judgmental factors may be considered, his region also uses the laugh test in deciding which penalty amounts to challenge.

Senior officials from EPA's Stationary Source Compliance Division and the Associate Enforcement Counsel from EPA's Office of Enforcement and Compliance Monitoring believe that EPA needs a flexible, easy to use administrative penalty authority to improve the Agency's ability to overfile in cases where assessed penalties are insufficient to recover the economic benefit the violator obtained and to deter future violations. According to these officials, such authority could enable EPA to impose economic benefit penalties against polluters expeditiously, thereby

allowing it to more frequently increase state and local agencies' penalties when warranted and to get maximum deterrent effect from EPA's limited resources. Substantial resources would be saved and more cases handled if EPA had greater administrative penalty authority, according to the Assistant Enforcement Counsel, who estimated that EPA would be able to close many cases for approximately $1,000 to $25,000 each.

Proposed Changes to Clean Air Act May Improve Penalties, but Clearer Direction Needed

In June 1989, the administration announced proposals for amending section 113 of the Clean Air Act, including providing EPA with the authority to administratively penalize sources up to $200,000 for violations of the act. Proposed section 113(e) specifically requires the economic benefit of noncompliance to be considered in determining the penalty amount and also allows EPA to assess penalties under section 120 back to the first provable date of the violation. In July and August 1989, legislation was introduced in the House and Senate to carry out the President's proposals.[3] Adoption and passage of these proposals appear to give EPA the enforcement tools and the desired flexibility and would negate limited enforcement authority as a reason if penalties continue to be insufficient to achieve deterrence.

The proposed revisions, however, do not address the issue of whether state and local enforcement programs can be required to collect penalties based on the economic benefit violators have obtained. According to senior EPA compliance officials, such legislative direction is needed to change the state and local agencies' practice of not adhering to EPA's civil penalty settlement policy. They pointed out that since the act makes no specific reference to the issue of state and local penalties, these agencies are likely to contest any EPA effort to require that economic benefit penalties be imposed. The EPA officials said that requiring these groups to assess economic benefit penalties appeared to be the most appropriate and practical remedy because (1) state and local programs will continue to carry out most enforcement actions and (2) EPA's enforcement resources will continue to be limited for the foreseeable future. The EPA officials said that additional legislative authority and/or direction would provide the necessary leverage to compel state and local programs to impose economic benefit penalties.

[3]The Clean Air Act Amendments of 1989 was introduced as H.R. 3030 in the House of Representatives on July 27, 1989, and as S.1490 in the Senate on August 3, 1989. The Senate passed its version of the clean air legislation, S.1630, on April 4, 1990, and the House passed a revised version of H.R. 3030 on May 23, 1990.

Conclusions

Both the Congress and EPA have recognized that one of the most important actions that can be taken to control air pollution from major stationary sources is to penalize violators in amounts sufficient to eliminate the economic benefit derived from the violation. Such penalties, if appropriately imposed, remove the economic and competitive advantage that the violator, through his actions, may have gained over facilities that complied with pollution control requirements. More importantly, economic benefit penalties can serve as strong incentives to major stationary sources to ensure that proper measures are taken to achieve and maintain compliance with pollution requirements and that violations do not occur.

However, state and local agencies have not always appropriately imposed penalties against major stationary sources. Because EPA has not used the SIPs or any other vehicle available to it to get state and local programs to commit themselves to economic benefit penalties, significant violators have paid penalties that were not based on the economic benefit derived and more than half of the violators have not paid any penalties at all. Further, the Agency has taken little action to overfile when penalties were inadequate. As a result, there appears to be little incentive for major sources to take all actions necessary to maintain compliance.

The proposed amendments to the Clean Air Act, if enacted, will provide an appropriate first step in solving this problem. Both the Senate and House bills provide EPA with the authority to impose economic benefit penalties administratively for violations back to the first provable date of the violation. This authority, if properly used, should allow EPA to overfile more efficiently in situations where insufficient penalties have been imposed by state and local programs and to better ensure that violators do not profit from polluting.

However, in the long run, the most effective method for ensuring that economic benefit penalties are appropriately imposed and collected is to have such penalty practices be a part of all state and local air pollution enforcement programs. To achieve this, standards for assessing economic benefit penalties need to be included in each SIP. The consistent requirement for such penalties in all programs will best ensure that violators are treated equally in all areas of the country and that firms that comply with air pollution controls are not placed at an economic disadvantage.

Although we believe EPA has the authority to require that economic benefit penalties be imposed, we recognize that EPA has to rely on state and local programs with differing enforcement philosophies to identify polluters and assess penalties, and that requiring rigid adherence to economic benefit enforcement standards may strain EPA's relationships with these programs. However, EPA's increased ability to overfile will, in our opinion, also improve EPA's ability to persuade state and local programs to impose penalties that reflect the economic benefit that the violator obtained. Once state and local programs realize that EPA will act to increase insufficient penalties—and that the federal government will retain the additional penalty amounts—it is likely that the states will be more willing to amend their SIPs to include economic benefit penalty provisions. Nevertheless, if EPA believes it needs greater statutory leverage in guiding state penalty practices, it should pursue additional legislative authority.

Recommendation to the Congress

Currently proposed amendments to the Clean Air Act contain provisions that provide EPA with administrative penalty authority that would enable it to take more expeditious actions to ensure that cash penalties are appropriate. We support these proposals and recommend that the Congress include such penalty authority in final Clean Air Act legislation.

Recommendations to the Environmental Protection Agency

To better achieve the objective of ensuring that those who violate the act's requirements do not gain financially from their actions, we recommend that the Adminstrator, EPA

- use the enforcement authority available now and in the future under the amended Clean Air Act to overfile to the maximum extent possible to increase inadequate state and local penalties and
- undertake efforts to include specific standards for assessing economic benefit penalties in the next round of SIP revisions and, if necessary and desirable, seek specific legislative endorsement for such action.

Major Contributors to This Report

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Sierra Club TEP RICE Comments
Exhibit 6

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Figure 1.2: Major Stationary Sources Releasing Visible Emissions

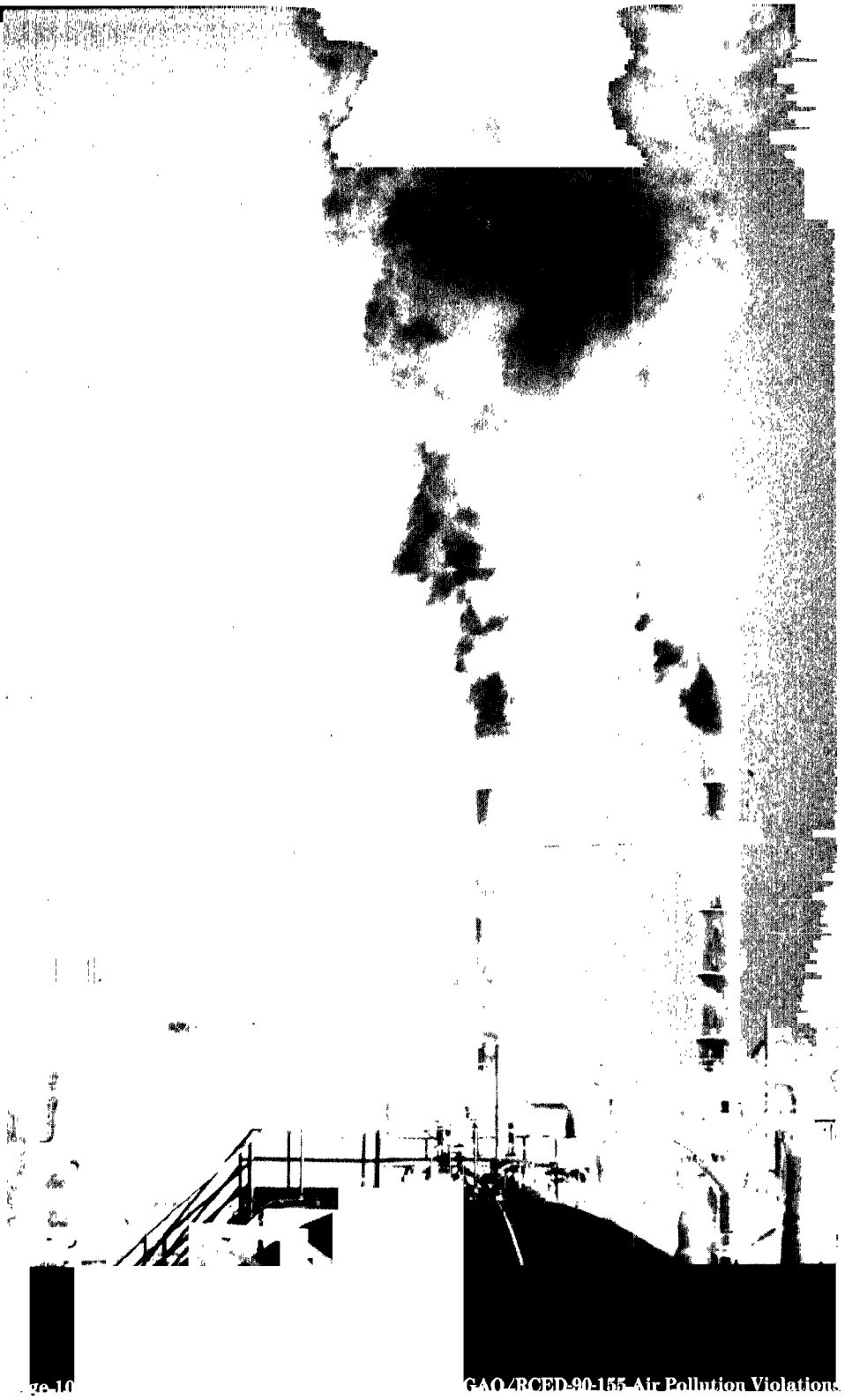
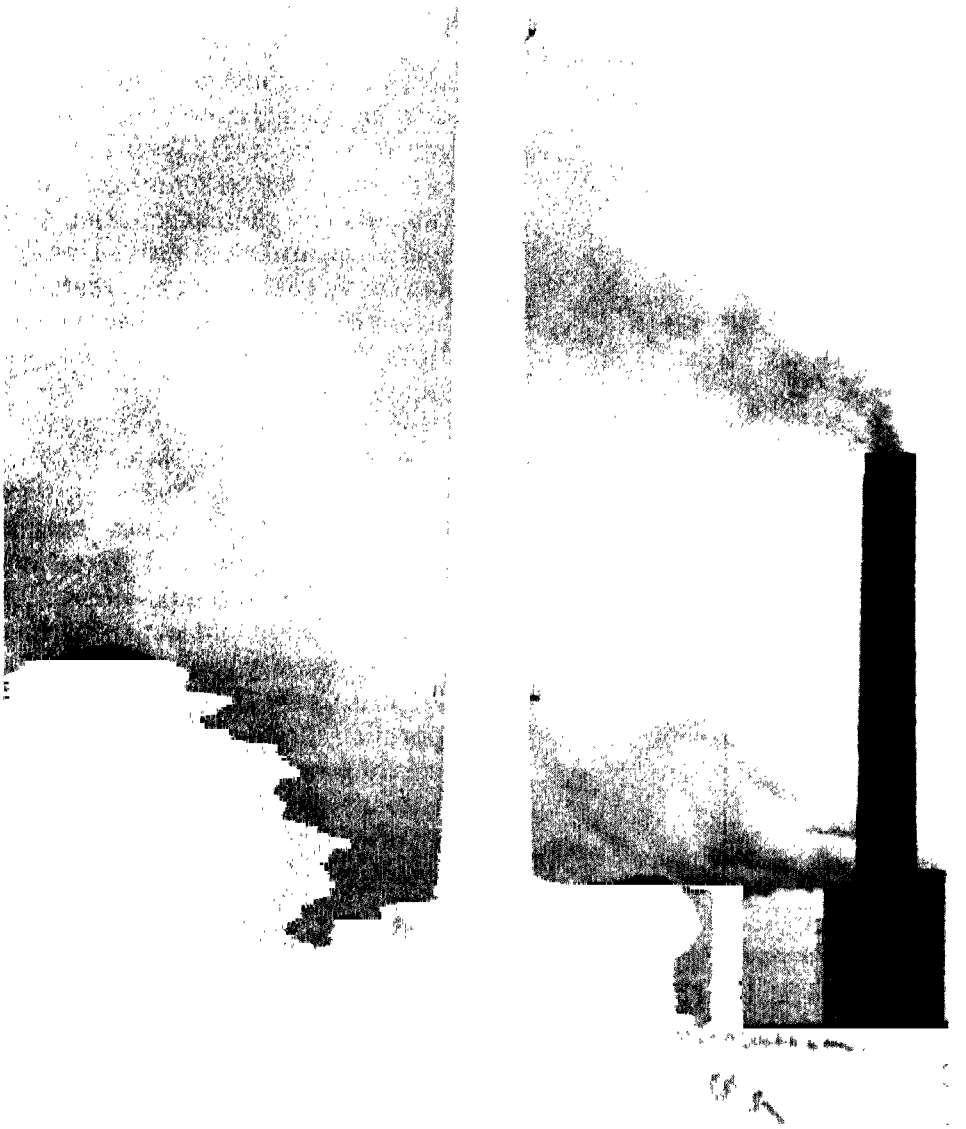


Figure 1.2: Continued



Source: EPA.

EXHIBIT 7

to Sierra Club Comments

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105

October 8, 2004

Mr. Jack Broadbent
Air Pollution Control Officer
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

Re: EPA Review of Proposed Title V/ Major Facility Review Permits:
Chevron Products Company (Richmond) #A0010,
ConocoPhillips Company #A0016 (Rodeo),
Shell Oil Products US #A0011 (Martinez),
Tesoro Refining and Marketing Company (Martinez) #B2758 & B2759,
Valero Refining Company #B2626 (Benicia)

Dear Mr. Broadbent:

We are enclosing with this letter the results of our review of the proposed permits the District submitted to EPA on August 25th, 2004 for Chevron Products Company; ConocoPhillips Company; Shell Oil Products US, Tesoro Refining and Marketing Company; and Valero Refining Company. Please note the following attachments to this letter: Attachment 1, "List of Objection and Reopening Issues;" Attachment 2, "List of Applicability and Monitoring Determinations;" Attachment 3, "List of Issues Addressed by BAAQMD by Letters dated October 6 and 8, 2004;" and Attachment 4, "List of Comments."

With respect to the issues identified in Attachment 1, EPA formally objects to the issuance of the proposed permits, pursuant to our authority under Clean Air Act ("CAA") section 505(b)(1) and the implementing regulations at 40 CFR § 70.8(c) (see also, BAAQMD Rule 2-6-411). Under CAA section 505(b)(1) and 40 CFR § 70.8(c), EPA may object to a proposed Part 70 permit that is determined not to be in compliance with applicable requirements or the requirements of Part 70. After EPA objects to a permit, the permitting authority has 90 days to revise and submit a proposed permit in response to the objection.

For the reasons set forth in our letter to you dated February 4, 2004, EPA is also invoking its reopening authority under section 505(e) of the Act and 40 CFR §70.7(g)(1). Pursuant to those authorities, EPA is notifying the District that cause exists to reopen the permit for the first issue identified in Attachment 1 ("Monitoring Required by 40 CFR NSPS VV, NSPS QQQ, and NESHAP V"). According to 40 C.F.R. §70.7(g)(2), BAAQMD has 90 days to submit to EPA a proposed determination in response to this notification. We believe that 90 days is a reasonable time frame for BAAQMD to submit revised permits to EPA in response to this notification.

With respect to the issues identified in Attachment 2, the District has agreed to submit applicability determinations to EPA by February 15, 2005 and to publish a notice to include any necessary revisions to the permits by April 15, 2005. This process will ensure that any unresolved applicability issues are addressed in a timely manner. The issues identified in Attachment 3 are those for which the District has agreed to make certain changes to the permits before issuing them. EPA appreciates the District's efforts to address EPA's concerns in these areas.

We are committed to working with you to resolve the issues we have identified as expeditiously as possible. If you have any questions concerning these issues, please contact me at (415) 947-8715 or have your staff contact Gerardo Rios, Chief of the Permits Office, at (415) 972-3974.

Sincerely,

Signed by

Deborah Jordan
Director, Air Division

Attachments

cc:
Adams, Broadwell, Joseph & Cardozo - Daniel Cardozo, et. al.
California Air Resources Board - Mike Tollstrup
Chevron Products Company - Jim Whiteside
Communities for a Better Environment - Will Rostov
Conoco-Phillips Company - Willie W. C. Chiang
Golden Gate University - Marcie Keever, et al
Shell Martinez Refinery - Aamir Farid
Tesoro Refining and Marketing Company - J. W. Haywood
Valero Refining Company - John U. Roach

Attachment 1
List of Objection and Reopening Issues

1. Monitoring Required by 40 CFR NSPS VV, NSPS QQQ, and NESHAP V
All Refineries

The permits lack monitoring to assure compliance with the following standards: 40 CFR 60.482-10(c), 60.692-5(a), and 61.242-11(c). These standards require that enclosed combustion devices be designed and operated to reduce VOC emissions by 95% or to provide a minimum residence time at a specified temperature.

The permits do not contain any way to show compliance with the residence time requirement, nor has the District indicated an intent to add a compliance method. We understand that residence time is to some degree a design specification in that the combustion chamber is designed to a specified volume to provide a target residence time for a given throughput. However, throughput to enclosed combustion control devices such as thermal oxidizers can vary, altering the residence time even for properly designed devices.

The standards cited above specifically require that enclosed combustion devices be designed *and operated* to provide a minimum residence time at a minimum temperature. Unless the District is able to adequately demonstrate that the control devices subject to these standards were designed to achieve the required residence time at the maximum anticipated flow rate, and that appropriate parameters are being monitored to assure compliance pursuant to 40 CFR 60.486(d), 60.697(d), and 61.246(d), flow rate monitors must be installed and operated.

2. Federal Enforceability of Permit Terms
Conoco-Phillips

The District has changed the designation for fuel limits that apply to many combustion sources from federally enforceable to not federally enforceable. For example, see Condition #1694 in Table IV - A.2 for Source S-3, and similar conditions that are listed for all of the combustion units other than gas turbines, flares, emergency engines, and newly added heater S-26. Limits created through prior NSR permits are federally enforceable Title V permit requirements. Please see March 31, 1999 letter from John Seitz, Director of EPA's Office of Air Quality Planning and Standards, to Doug Allard, CAPCOA President.

Please note also that the statement of basis states that Conoco-Phillips has relied on throughput limits in this condition to determine that New Source Review does not apply in at least several cases, as noted in Application 5814, attachment F. For instance, section 2.7.1 states that due to the condition 1694 "existing permit conditions limiting

fuel use ... increased production of steam will not be considered a modification and increase will not be quantified."

The District has agreed to review the following applicability and monitoring determinations by February 15, 2005 and to publish a public notice of any necessary revisions to the permits by April 15, 2005.

3. 40 CFR Part 63 (MACT), Subpart CC applicability for Flares
All Refineries

The Refinery MACT (40 CFR Part 63, Subpart CC) is not included in the applicable requirements tables for flares in any of the refinery Title V permits. Subpart CC contains an exemption from testing, monitoring, recordkeeping, and reporting (TMRR) requirements for refinery fuel gas systems or emission points routed to refinery fuel gas systems (40 CFR 63.640(d)(5)). The revised statements of basis for the Chevron, Shell, and Valero permits indicate that the District considers all emissions from emission points connected to a vapor recovery system the fuel gas system to be exempt, even if the vapor recovery system is not operated and the emissions are flare instead. (See, for instance, p20 of the Valero Statement of Basis) The District therefore proposes to exempt all flares from Subpart CC's testing, monitoring, recordkeeping, and reporting (TMRR) requirements. (The statements of basis for Conoco-Phillips and Tesoro do not contain any applicability determination for flares.)

The District's position that flares are categorically exempt from Subpart CC when used as a alternative to a fuel gas system (see Valero p20) is incorrect. Gases directed to a flare instead of the fuel gas system are not part of the fuel gas system, even if there is common piping between where gases are released from a unit and where the system branches off to either the flare, or the fuel gas system. While the statements of basis for the five refineries generally do not contain enough information to determine applicability, the information in the Valero permit and Statement of Basis indicate that Valero flares S-18 and S-19 are examples of incorrect applicability determinations.[1]

The District has agreed to review the applicability determinations regarding flares and MACT Subpart CC. For all flares subject to MACT Subpart CC, the Title V permit for any such flare must include the applicable requirements of MACT CC, such as 40 CFR 63.643(a)(1), 63.644(a)(2), and 63.653(a)(1), and Subpart A (note that the Tesoro permit contains citations to 63.11 but not the other requirements in Tables IV-U, IV-Xb, IV-Xc,

[1]Table II A of the Valero permit states that four permitted flares S-16, S-17, S-18, and S-19 burn refinery waste gas. The District requires that Valero use S-18 and S-19 as a routine emissions control device (p. 413 of Table IV and pp 432-3 of section VI), as opposed to other units (p 485 in Section VI of the permit) that are required to vent to the refinery fuel gas system or a boiler.

and Xd).

4. Unit-specific NESHAP Subpart FF Requirements
Tesoro

Although the requirements of 40 CFR Part 61, Subpart FF are applicable to the Tesoro refinery, the District did not identify the subpart as an applicable requirement in any unit-specific tables in the permit. The complexity of the regulation, coupled with the lack of specificity in the permit, make the compliance obligations of the facility unclear.

5. Regulation 8-2 and Hydrogen Plant Vents
Shell and Tesoro

The Shell and Tesoro permits fail to include Regulation 8-2, Miscellaneous Operations, as an applicable requirement for CO_2 vents (also called "dearator") or other vents at Shell Hydrogen Plants 1, 2 and 3 and Tesoro Hydrogen Plant 1. CO_2 generation is an inherent part of the steam-methane reforming process of generating hydrogen at refineries, which also results in volatile organic compound and/or Hazardous Air Pollutant byproducts that are controlled at all of the three other refineries.[2] Thus, the Statement of Basis will need to explain any decision that the rule does not apply; and the permits must contain all conditions, including all control devices and compliance requirements, necessary to assure compliance with Rule 8-2 limits. See for example Shell Proposed Table IV-B, Table IV-AL, Table IV-CR, Table VII-A, Table VII-AE, and Table VII-CA

6. Cooling Tower Monitoring
All Refineries

The District has requested information from the refineries regarding the current operation and maintenance practices for their cooling towers. This information will be used to make an applicability determination and include all conditions necessary to assure compliance with Regulation 8-2.

7. Unpermitted Cooling Towers
ConocoPhillips

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[2]Shreve's Chemical Process Industries Fifth Edition confirms that the products of the hydrogen plant are hydrogen and CO2 (p.107). Chevron permits includes scrubbers and scrubber monitoring (see p.40 of Table II-B, on-line version); Conoco-Phillips has installed a scrubber as noted in our prior comments; and the Valero permit (Table IV-D4, Section VI, and Table IV-D4) requires incineration of all hydrogen plant unit # S1010 dearator vent emissions in a boilers. In addition, refineries have installed reformulated catalysts.

The ConocoPhillips permit does not contain any requirements for the facility's cooling towers nor does it identify the cooling towers as emission units. The refinery has submitted permit applications for these units and the District is in the process of issuing Authority to Construct permits for the cooling towers and will also add amend the Title V permit.

8. Slop Oil Vessels and Sludge De-watering Operations
Tesoro

In response to a comment (# 118) requesting that the District determine if the Tesoro refinery contains any slop oil vessels or sludge de-watering operations, the District will conduct a thorough review to determine if they are present at the facility.

9. NSPS QQQ Requirements for Oil-Water Separators
Shell

The Shell permit is missing NSPS Subpart QQQ requirements for the facility's oil-water separators and slop oil vessels.

10. NSPS Subpart QQQ and Reg. 8-8 Wastewater Requirements for Slop Oil Vessels
Chevron

The District has previously taken the position that NSPS Subpart QQQ and Reg 8-8 requirements do not apply to the slop oil vessels at the Chevron refinery on the basis that the facility uses controlled tanks - not vessels - for slop oil accumulation. NSPS Subpart QQQ and Reg 8-8, however, do not appear to distinguish between tanks and vessels. Beyond this question of interpretation, however, applicability of these regulations to Chevron's slop oil vessels has not been evaluated.

11. NSPS Subpart QQQ Applicability Determination for New Process Units
Valero

The NSPS Subpart QQQ applicability determination for S-161 in the Valero Statement of Basis indicates that two process units have been constructed in the refinery since 1987. It further states that process wastewater from these units is hard-piped to an enclosed system. While the District discussed the applicability of Subpart QQQ for S-161, it did not discuss the applicability of the subpart specifically for the hard piping and enclosed system installed after 1987. The hard piping appears to meet the definition of a "sewer line" under 60.691 and may be regulated under 60.692- 1(c). Furthermore, it is not clear if the enclosed system that receives the process waste is included in the permit or if it was considered in the applicability determination.

12. NESHAP Subpart FF Requirements for Biotreaters
Shell

The District's position that biotreaters are categorically exempt from NESHAP Subpart FF requirements is inconsistent with Subpart FF's definition of "wastewater treatment systems," which includes biological treatment units. Subpart FF, however, also contains exemptions for biotreaters in some cases. Therefore, applicability of Subpart FF to the biotreaters at the Shell refinery has not been fully evaluated.

13. NESHAP Subpart FF – 10% Annual Average Water Content
Valero, Shell, Chevron

The District's applicability determinations for NESHAP Subpart FF for Valero and Shell and Response to Comment regarding the Chevron permit contain incorrect statements. For example, the District's applicability determination regarding Valero's sewer pipeline and process drains states:

> Valero complies with FF through 61.342(e)(2)(i), which allows the facility 6 Mg/yr of uncontrolled benzene waste. Thus, facilities are allowed to choose whether the benzene waste streams are controlled or uncontrolled as long as the uncontrolled stream quantities total less than 6 Mg/yr...Because the sewer and process drains are uncontrolled, they are not subject to 61.346, the standards for individual drain systems.

While it is true that some waste streams may go uncontrolled under the chosen compliance option, there is a restriction in Subpart FF, which the District did not discuss in its applicability determinations. Section 61.342(e)(1) states that, "the owner or operator shall manage and treat facility waste with a flow-weighted annual average water content of less than 10% in accordance with the requirements of paragraph (c)(1) of this section." As a result, the only waste streams that may go uncontrolled under 61.342(e)(2) are those with an annual average water content greater than 10%. It is not clear from the District's applicability determinations that the waste streams in S-161 and S-32105 meet this requirement. Similar issues arise for the Shell and Chevron permits.

The District's silence on this issue raises a question as to whether the control requirements of 61.342(e)(1) were considered at all for the operations at the refineries. Therefore, the District should verify that all uncontrolled waste streams under the 6BQ compliance option meet the water content requirement under 61.342(e)(2). If the waste streams do meet the requirement, the District should revise the statements of basis to reflect that finding. If the annual average water content in any of the uncontrolled waste streams is less than 10%, the District should add the appropriate requirements to the

permit and revise the applicability determinations and response to comments accordingly.

14. NESHAP Subpart FF– 6BQ

The District stated that facilities are allowed to choose whether the benzene waste streams are controlled or uncontrolled as long as the uncontrolled stream quantities total less than 6 Mg/yr; this statement is not entirely correct. Section 61.342(e)(2) requires all wastes with a water content of 10% or greater (hereafter referred to as "aqueous waste") to comply with the wastewater provisions in the subsequent paragraphs. For the purposes of the 6.0 Mg/yr limit, this compliance option does not distinguish between "treated" and "untreated" aqueous wastes. Therefore, the sum of all aqueous wastes (controlled and uncontrolled) must be equal to or less than 6.0 Mg/yr. It is not clear if, in selecting which waste streams to leave untreated, the refinery applied the misinterpretation of the regulation that is communicated in the District's applicability determination. If that is the case, it is possible that the refinery will need to control additional waste streams so the total benzene quantity in both the controlled and uncontrolled systems is less than the 6 Mg/yr limit. To ensure that the permit assures compliance with the requirements of Subpart FF, the District should verify that the refinery properly meets the 6 Mg/yr limit. In doing so, the District should determine whether or not its previous misinterpretation of the regulation led to inappropriate conclusions regarding what waste streams may go untreated.

13. Electro-Static Precipitator Particulate Monitoring
Chevron, Shell, Tesoro, Valero

The District has committed to working with EPA to analyze the relevant technical data and develop permit conditions that require Shell, Tesoro, and Valero to monitor ESP operating parameters. We anticipate that the District will select appropriate monitoring parameter(s) and specific range(s) and revise the permits accordingly.

Four of the refineries operate electro-static precipitators (ESPs) to control emissions from fluidized catalytic cracking units (FCCU), carbon monoxide boilers (burning FCCU gas), cokers, and at Valero other units as well (Table II-A of permitted sources in the proposed Conoco permit does not list any ESP). These emissions can amount to thousands of tons per year, if they are not controlled. Bay Area SIP rules 6-310 and 6-311 limit the concentration and mass of the particulate emissions from the ESP in each case, but lack monitoring. Therefore the permits must be revised to include periodic monitoring under 70.6(a)(3)(B).

The District has added annual testing to permits that previously lacking PM testing for the FCCU emissions. Annual testing at the ESP outlet, however, is inadequate because there is no way to determine whether the control device is operating at a level that meets

the applicable requirements during the rest of the year.[3]

The District has also added opacity monitoring for the opacity limit that is also contained in Rule 6 where the opacity monitoring was lacking in the permit, and in some cases appears to cite it as a monitoring requirement for the particulate limits (for instance, see Tesoro Table VII-V). While we agree that monitoring for the opacity limit is appropriate, no connection has been established in the rule or in the permit between compliance with the opacity limit in the SIP and the particulate limits.

The Chevron permit (see Table VII.C.2.1) requires four source tests per year and parameter monitoring for the applicable New Source Review limit. The District should either demonstrate that it has already conducted a review that shows that the NSR monitoring in the Chevron permit is adequate periodic monitoring for the SIP, or conduct a similar monitoring review for the Chevron permit.

Also, we recommend correcting the monitoring listed in Shell permit Table VII-AG for 63.1654(a)(1)(i), which appears to indicate that meeting the NSPS opacity limit of 30% will satisfy the monitoring requirements for the lb PM/lb coke burn-off emission rates. While opacity could be selected as a monitoring approach for the PM limit, it is incorrect to assume that compliance with the NSPS Subpart J 60.102(a)(2) opacity limit for these units assures compliance with the separate PM limit under 63.1654(a)(1)(I).

[3]We understand that the testing will occur at the outlet of the ESP. We suggest clarifying in the revised permits the relationship between emissions at the FCCUs, as well as other emission units, and the ESPs; and where source testing will occur.

15. Support Facilities
All refineries

Certain operations at the refineries may qualify as support facilities. Examples of such operations include:

--loading racks at each of the refineries;
--hydrogen plants located at the Tesoro and Shell refineries, which are owned and operated by Air Products;
--the wastewater operation located at the Shell refinery, which is owned and operated by Sierra Processing; and
--the facility identified as Shell Chemical Lp (ID 12870) in the CARB Emissions Inventory database.

It is currently unclear whether these operations are support facilities. The District has agreed to determine if these operations require Title V permits and to require permits for any operations that are support facilities. Specifically, the District has agreed to meet the following schedule:

November 1, 2004	Provide a list of all permitted facilities adjacent to each refinery.
January 1, 2005	Provide EPA with an analysis of each pairing to determine whether a) a support facility relationship exists, and b) whether the pairing comprises a single facility for Title V purposes.
February 1, 2005	Transmit to each facility determined to be subject to Title V a letter requiring submittal of a title V permit application.

16. Recordkeeping for NSPS QQQ and NESHAP Subpart FF Compliance Options
Chevron

The Benzene Waste Operations NESHAP (Subpart FF) contains several different options that facilities may use to comply with the general standards under 40 CFR 61.342 if the total annual benzene quantity from the facility waste is greater than or equal to 10 Mg/yr; among them are:

--61.342(c) - waste management and treatment requirements for facilities at which the total annual benzene quantity from the facility waste is equal to or greater than 10 Mg/yr
--61.342(d) - an alternative to the requirements under 61.342(c)
--61.342(e) - an alternative to the requirements under 61.342(c) and (d)
--61.342(f) - off-site treatment option as an alternative to 61.342(c)(1)(i) (not available to facilities complying under 61.342(e))

The proposed Chevron permit contains all four compliance options (see Table IV.G.1.1).

Attachment 3
Issues Addressed in District Letters Dated October 6 and 8, 2004

The manner in which the District included all of these requirements in the permit leaves it unclear as to which option the facility has selected and with which requirements it must comply.

Similarly, the Wastewater NSPS (40 CFR Subpart QQQ) contains several compliance options. For individual drain systems, a source may comply with the requirements of 60.692-2 or 60.693-1. If a source complies with NSPS Subpart QQQ using the requirements of 60.692-2, pursuant to 60.692-2(a)(3) the source must conduct weekly inspections of all drains out of active service unless the source chooses to comply with 60.692-2(a)(4) which allows the source to tightly seal the drains and conduct semiannual inspections. For oil-water separators the source may comply with the requirements of 60.692-3 or 60.693-2. If a source complies with NSPS Subpart QQQ using the requirements of 60.692-3, pursuant to 60.692-3(b) an oil-water separator with a design capacity to treat more than 16 liters per second must use a closed vent system and control device unless the source meets the requirements of 60.692-3(c)(1), in which case the source may comply with 60.692-3(a) or (c)(2).

The District has agreed to add a federally enforceable condition prior to issuing the permit requiring that Chevron maintain records of the compliance option it is using at any given time.[4]

1. NSPS Subpart A requirements for Flares
Chevron, Shell, and Tesoro

NSPS Subpart A is not included in the permits for all flares subject to the requirements of 40 CFR Part 60, Subpart A (i.e. Subpart J flares, including those used for emergencies and process upsets only). As the District concurred (for instance in the revised Statement of Basis for Shell), Subpart A is an applicable requirement for all flares meeting the applicability criteria of 40 CFR 60.100(a) and (b), including flares that are exempt from the H_2S limit pursuant to 40 CFR 60.104(a)(1).

The District has agreed to review the applicability of Subpart A and to add any applicable requirements prior to issuance.

2. Valero Permit Shield from Rule 8-2 Not Public Noticed
Valero

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[4] For clarity, EPA also recommends that the District remove the citation to 61.342(a), which applies to facilities whose waste benzene quantity is less than10 Mg/yr because the benzene quantity from the facility waste exceeds this threshold.

Attachment 3
Issues Addressed in District Letters Dated October 6 and 8, 2004

Valero's permit contains a shield against Rule 8-2 on the basis that the flares meet the 90% control efficiency exemption criteria of 8-1-110. This permit shield was never public noticed.

The District has agreed to delete this shield. If the District chooses to re-propose Valero's permit with the shield in it, the permit must demonstrate that the flares are meeting the basis for the shield.

3. Tesoro Permit Shield from Rule 8-2
Tesoro

Tesoro's permit contains a shield against Rule 8-2 on the basis that all seven flares at the refinery are subject to Regulation 10, which incorporates the New Source Performance Standards (NSPS) by reference. While the permit indicates in Section IV that all flares are subject to Regulation 10, only three flares appear to be subject to NSPS.

The District has agreed to delete this shield.

4. Assuring Compliance with 40 CFR NSPS VV, NSPS QQQ, and NESHAP V

40 CFR 60.482-10(c), 60.692-5(a), and 61.242-11(c) require that enclosed combustion devices be designed and operated to reduce VOC emissions by 95% or to provide a minimum residence time at a specified temperature. Though the District indicated in its Response to Comments #21 that temperature monitoring would be added to Section VII of the permits, temperature monitoring is missing from Chevron's Table VII.H.2.1 for 60.692-5(a), ConocoPhillip's Table VII-AB for 60.692-5(a) and 60.482-10(c), and Tesoro's Table VII-CF for 60.692-5(a).

The District has agreed to include this temperature monitoring prior to issuing the permits.

5. Facility-Wide Permit Shields
Shell

Section X, Table A-10 of the Shell permit contains 23 facility-wide permit shields, including: shields from six benzene regulations; six SOCMI regulations; NSPS Subpart D, Da, and Dc; the hazardous waste MACT for combustion equipment; two regulations for gasoline bulk loading terminals; one for chromium water treatment compounds; one regulation (40 CFR part 63 subpart SS) for certain MACT categories; one regulation for sulfuric acid plants; and one sulfur dioxide standard.

Attachment 3
Issues Addressed in District Letters Dated October 6 and 8, 2004

As we noted in our letters of October 31, 2003, April 14, 2004, and July 28, 2004, these shields must be appropriately supported and justified. Section 70.6(f)(1) allows the inclusion of a shield provided that the permitting authority "determines in writing that other requirements specifically identified are not applicable to the source, and the permit includes the determination or a concise summary thereof." EPA has determined that the Shell permit does not adequately support 22 of the 23 shields.[5] The permit does not cite a specific regulatory basis, which in many cases is necessary to part of an applicability determination. It also lack facts and analysis, which are generally necessary to explain the District's determination that the source qualifies for an exemption. Conclusory statements that a regulation does not apply do not satisfy the requirement to include an applicability determination in the permit. Thus, the permit lacks an applicability determination as the justification for the shields.

The District has agreed to review these shields and to clarify to EPA's satisfaction, the basis for any shield in the permit prior to issuing the permit, or will delete the shield from the permit.

[5]The shield from 9-1-302 states the regulatory basis for the exemption (fence-line monitoring of SOx in lieu of limits on individual stacks), and we located a corresponding permit condition requiring fence-line SOx monitoring in Section IV of the permit (which we recommend cross-referencing in the permit shield determination).

Attachment 3
Issues Addressed in District Letters Dated October 6 and 8, 2004

1. New Source Review and Throughput Limits for Shell gas turbine/supplemental steam generators #1 and #2 (unit S-4190/4191, and S-4192/4193)

Shell has requested an increase to throughput limits on the cogeneration plants in condition 18618. They have requested an increase from 470 mmbtu/hr to 548 mmbtu/hr for the turbines and 222 mmtu/hr to 258 mmbtu/hr for the supplemental steam generators (to be expressed as a daily average). We believe that Shell needs to clarify in the Statement of Basis why New Source Review does not apply. Please note that District will need to re-examine the 24-hour start up and shut-down exemptions that currently apply under condition 12271 items #22 and 24 for any new BACT and/or offset review.

Shell permit condition 18618 cross-references local District rule 2-1-234.3 for NSR applicability determinations in some circumstances. Please remove this citation, or replace it with a citation to SIP approved Rule(s) for any discussion of NSR applicability in this section. Please note that the description states that condition 18618 applies to "grandfathered" units that have not undergone NSR, but the condition also includes the gas turbines. As noted below, these units are subject to New Source Review rather than "grandfathered" units.

2. Clarity of Reg 8-8 requirements in Table IV.G.1.4

Chevron

Although the requirements of Reg 8-8-301 (wastewater separators greater than 760 liters per day and smaller than 18.9 liters per second) and Reg 8-8-302 (wastewater separators larger than or equal to 18.9 liters per second) apply to separators of different capacities, Table IV.G.1.4 (separator cluster 30c) contains references to both sets of requirements. As a result, it is unclear which requirements apply to each of the three separators in the cluster. To clarify the permit, EPA recommends that the District remove citations to the section of the regulation that does not apply (if they are all in the same capacity range) or divide the units into two separate tables and include the appropriate requirements in each table. Such clarification would be particularly useful for the corresponding table in Section VII (Table VII.G.1.4) because Regs 8-8-301 and 8-8-302 each have alternative compliance options and it is difficult to tell from the permit what requirements apply to each unit. As noted in other comments regarding compliance options, we believe that the District needs to add a permit condition that requires recordkeeping of the compliance option that the refinery is using for each unit at any given time.

3. Monitoring for Reg 8-8-112

Chevron

Table IV.G.1.4 of the Chevron permit contains a reference to the exemption under Reg 8-8-112 for separators with wastes that meet certain organic compound concentration or temperature criteria. However, table VII.G.1.4 is missing the monitoring requirement in Reg 8-8-502, which applies to sources operating under exemption. The District previously indicated that the exemption was included in the permit for informational purposes and operational flexibility even though the refinery may not currently operate under it. While it is true that the Permittee may choose which compliance option it wishes to use, the permit must assure compliance with each option that is included in the permit. As a result, the District should add the monitoring and recordkeeping requirements of Reg 8-8-502 to Table VII.G.1.4. Note that this comment also applies to Process Drain Clusters 20d and 20q. As noted earlier, we believe that the District also needs add a condition that requires the refinery to maintain records of which compliance option it uses.

4. Permit Reformatting

General

We understand that the District intends to reformat the permits. We believe that the consolidation of the applicable emission limits and monitoring into a single section will be very helpful. We have found that having a table of contents for the permit (see Chevron) very helpful. A table of contents for Section VI permit conditions (see Valero) will also be helpful if the District is not able to integrate those conditions into the new, consolidated list of applicable requirements and monitoring.

EXHIBIT 8

to Sierra Club Comments

November 1, 1999

4APT-ARB

Howard L. Rhodes, Director
Air Resources Management Division
Florida Department of Environmental Management
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: EPA's Review of Proposed Title V Permit No. 0170004-004-AV
Florida Power Corporation Crystal River Plant

Dear Mr. Rhodes:

The purpose of this letter is to notify the Florida Department of Environmental Protection (FDEP) that the U.S. Environmental Protection Agency (EPA) formally objects to the issuance of the above referenced proposed title V operating permit for the Florida Power Corporation (FPC) Crystal River Plant in Citrus County, Florida, which was received by EPA, via e-mail notification and FDEP's web site, on September 17, 1999. This letter also provides our general comments on the proposed permit.

Based on EPA's review of the proposed permit and the supporting information received for this facility, EPA objects, under the authority of Section 505(b) of the Clean Air Act ("the Act") and 40 C.F.R. § 70.8(c) (see also Florida Regulation 62-213.450), to the issuance of the proposed title V permit for this facility. The basis for EPA's objection is that the permit does not assure compliance with all applicable requirements as required by 40 C.F.R. § 70.1(b) and 40 C.F.R. § 70.6(a)(1). Specifically, the permit does not contain terms or conditions assuring compliance with Prevention of Significant Deterioration requirements applicable to this facility under the Clean Air Act, the Florida State Implementation Plan, and 40 C.F.R. part 70. In addition, the permit does not fully meet the periodic monitoring requirements of 40 C.F.R. § 70.6(a)(3)(i), and the permit does not assure compliance with the requirements of 40 C.F.R. § 70.6(a)(1). Pursuant to 40 C.F.R. § 70.8(c), this letter and its enclosure contain a detailed explanation of the objection issues and the changes necessary to make the permit consistent with the requirements of 40 C.F.R. part 70 and assure compliance with applicable requirements of the Clean Air Act. The enclosure also contains general comments applicable to the permit.

Section 70.8(c) requires EPA to object to the issuance of a proposed permit in writing within 45 days of receipt of the proposed permit (and all necessary supporting information) if EPA determines that the permit is not in compliance with the applicable requirements under the Act or the requirements of 40 C.F.R. Part 70. Section 70.8(c)(4) of the title V regulations and Section 505(c) of the Act further provide that if the State fails to revise and resubmit a proposed permit within 90 days to satisfy the objection, the authority to issue or deny the permit passes to EPA, and EPA will act accordingly. Because the objection issues must be fully addressed within the 90 days, we suggest that the revised permit be submitted in advance in order that any outstanding issues may be resolved prior to the expiration of the 90-day period.

If you have any questions or wish to discuss this further, please contact Mr. Gregg Worley, Chief, Operating Source Section at (404) 562-9141. Should your staff need additional information, they may contact Ms. Kelly Fortin, Environmental Engineer, at (404) 562-9117 or Ms. Lynda Crum, Associate Regional Counsel, at (404) 562-9524.

Sincerely,

Original Signed by:
James S. Kutzman for

Winston A. Smith
Director
Air, Pesticides & Toxics
Management Division

Enclosure

cc: Joseph H. Richardson, President & CEO, FPC
W. Jeffery Pardue, Director Env. Services, FPC
Clair Fancy, P.E., FDEP
A. A. Linero, FDEP

Enclosure

U.S. EPA Region 4 Objection
Proposed Part 70 Operating Permit
Florida Power Corporation Crystal River Plant
Permit No. 0170004-004-AV
November 1, 1999

I. EPA Objection Issues

1. Applicable Requirements - Based on our review of the proposed permit, the title V permit application, and supplemental materials, EPA has determined that the proposed permit for the FPC Crystal River facility does not assure compliance with all applicable requirements under the Clean Air Act (CAA or the Act), the Florida State Implementation Plan (SIP), and state and federal title V regulations. Specifically, the permit does not contain terms and conditions assuring compliance with applicable Prevention of Significant Deterioration (PSD) requirements of the Act, the Florida SIP, and 40 C.F.R. part 70 for a proposed major modification to allow the facility to burn petroleum coke ("petcoke").

   Pursuant to CAA § 504(a), title V permits are to include, among other conditions, "enforceable emission limitations and standards, . . . and such other conditions as are necessary to assure compliance with applicable requirements of [the Act], including the requirements of the applicable implementation plan." "Applicable requirements" are defined in 40 C.F.R. § 70.2 to include: "(1) any standard or other requirement provided for in the applicable implementation plan approved or promulgated by EPA through rulemaking under title I of the Act..." As you know, FDEP defines "applicable requirement" in a similar fashion to include, among other requirements, "any standard or other requirement provided for in the state implementation plan" 62-210.200(31)(a)(1) Florida Administrative Code (F.A.C.).

   Applicable requirements include the requirement to obtain preconstruction permits that comply with applicable preconstruction review requirements under the Clean Air Act, EPA regulations, and SIPs. See generally CAA §§ 110(a)(2)(C), 160-69, & 173; 40 C.F.R. §§ 51.160-66 & 52.21; see also Order In re Roosevelt Regional Landfill, at 2, 8 (May 4, 1999); Order In re Monroe Electric Generating Plant Entergy Louisiana, Inc., at 2 (June 11, 1999). Such applicable requirements include the requirement to obtain a PSD permit that in turn complies with applicable PSD requirements. See CAA § 165;
   40 C.F.R. §§ 51.160, 51.166 & 52.21; 48 FR 52,713 (November 22, 1983);
   Rule 62-212.400 F.A.C. Those requirements include, but are not limited to: the use of best available control technology (BACT) for each regulated pollutant that would be emitted in

significant amounts, at each emissions unit at which the increase would occur; associated emission limitations; and any additional requirements resulting from the PSD review, such as those that are necessary to afford protection to any Class I area air quality related values.[1]

The *FPC Crystal River Facility Title V Air Operating Permit Application*, signed June 12, 1996, indicates that on December 26, 1995, FPC submitted to FDEP a request to allow the Crystal River facility to burn a blend of petroleum coke and coal in Units 1 & 2.[2] This proposed modification would result in an actual emissions increase of approximately 9,400 tons per year of sulfur dioxide and a corresponding increase in the potential emissions of sulfur dioxide of approximately 18,700 tons per year. There are no scrubbers present or planned for Units 1 & 2 to abate this emissions increase.

As you are aware, a major source is subject to PSD requirements if the proposed modification will result in a significant net emissions increase of 40 tons or more per year of sulfur dioxide.[3] See 40 C.F.R. §§ 51.166(b)(2), 51.166(b)(23) & 51.166(i); see also 62-212.400(2)(e)2 F.A.C. Hence, it is our determination that the proposed modification is a major modification subject to PSD review.

FPC's application, however, did not address PSD requirements, because FPC contended that it qualified for an exemption from PSD permitting requirements under Rule 62-212.400(2)(c)4 F.A.C. This FDEP rule, as well as federal PSD requirements at 40 C.F.R. § 51.166(b)(2)(iii)*(e)(1)*, exclude from the definition of major modification the use of an alternative fuel or raw material which:

> the source was capable of accommodating before January 6, 1975, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975. . . .

We are aware that after reviewing FPC's application to burn petcoke, FDEP originally issued an Intent to Deny the permit on June 25, 1996. Following an administrative hearing and a series of procedural events, FDEP issued a Final Order denying the permit on March 2, 1998. FPC appealed this decision to the Fifth District Court of Appeal of Florida (5th DCA).

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[1]This facility is located within 15 km of the Chassahowitzka Wilderness Area.

[2]Units 1 and 2 are coal-fired fossil fuel steam generating boiler with associated coal handling and conveying equipment and electrostatic precipitators. They have generator ratings of 440.5MW and 523.8MW respectively.

[3]Pursuant to the "WEPCO" rulemaking, a utility may use an "actual to future actual test," rather than an "actual to potential test," for calculating the future emissions increase 40 C.F.R. § 51.166(b)(32) (See FR 32314, July 21, 1992). Under either test, the proposed modification will result in a net emissions increase substantially above the major modification significance threshold for sulfur dioxide.

However, following negotiations with FPC, FDEP agreed to vacate the Final Order and joined with FPC in filing a Joint Motion for Relinquishment of Jurisdiction with the 5th DCA. On January 11, 1999, FDEP granted FPC a final state construction permit to authorize the burning of a petcoke-coal blend in Units 1 and 2. This permit was not issued pursuant to the State PSD regulations, and hence, does not meet the requirements of the CAA, Federal PSD Regulations or the Florida SIP. In addition, this permit was issued without an opportunity for public or EPA review. The proposed title V permit is, thus, the first opportunity for EPA to comment on the permit conditions related to the proposed modification. It is our understanding that the facility has not commenced burning of petcoke.

EPA has reviewed the supporting information related to the above proceedings, including, but not limited to: supplemental information submitted by FPC to EPA on January 6, 1997, February 11, 1997, February 18, 1997, February 21, 1997, February 28, 1997, and May 21, 1997; information submitted by FDEP to EPA on December 24, 1996 and May 13, 1997; the Recommended Order of the administrative law judge (ALJ) following the FDEP's administrative hearing (September 23, 1977); the FDEP's Final Order to Deny the permit (March 2, 1998) ; and the subsequent vacature of that order (January 4, 1999). As communicated in our letters to Howard L. Rhodes, dated June 2, 1997 and July 30, 1997, and for the reasons outlined below, EPA continues to maintain that the exemption for alternative fuels given in 40 C.F.R. § 51.166(b)(2)(iii)*(e)(1)* and as incorporated into the SIP at 62-212.400(2)(c)4 F.A.C., is not applicable for the purpose of the proposed petroleum coke modification, and thus, the proposed modification is major modification subject to PSD review.

A. <u>The facility was not capable of accommodating petroleum coke as of January 6, 1975</u>

The administrative hearing record and other supporting information submitted by FPC and FDEP, including discussion of a facility inspection by FDEP on December 16, 1996, indicate that Unit 2 was physically unable to burn solid fuel as of January 6, 1975. Only through substantial modifications made during the late 1970's to reconvert Units 1 and 2[4] to coal-fired facilities, did Unit 2 regain the ability to burn coal. The record is unclear as to whether the Unit 1 boiler remained capable of burning coal during the time that it burned fuel oil. However, during the "reconversion" process, modifications to Unit 1 included replacement of most of the waterwall, addition of

[4]EPA intends for references to "Units 1 & 2" to mean all associated equipment necessary for operating coal-fired boilers 1 & 2, including, but not limited to, the heat recovery steam generators, coal handling, conveying and pulverizing systems, and ash handling equipment. Use of the term "facility" would be inappropriate in the case, since the Crystal River Plant is also comprised of two additional coal-fired units and a nuclear unit.

induced draft fans, replacement of pollution control equipment, and addition of railroad tracks to the area. According to the hearing witness for FDEP, the physical alterations were required to make the units capable of accommodating coal. Further, it is not clear that the blending capability to
co-fire coal and petcoke was present prior to 1975.

Some of the physical modifications, as documented by FPC, necessary to convert the units back to coal include changes or additions of coal burners; piping for sootblowers, service air, flame scanners, drip drain vents, precipitators, ash water, pyrites, and fluidizing air; coal transport piping, pulverizers and motors; coal feeders; ignitor horns, soot blowers, and flame scanner systems; bottom ash hopper and clinker grinders; ash pond, ash sluice system, and flyash removal system, etc. These modifications were documented to cost over 17 million dollars (past value), and it appears that many of these modifications were necessary to convert the facilities to coal-fired units, rather than to simply bring the units into compliance while burning coal, as characterized by FPC (Letter to Mr. Brian Beals, EPA, December 24, 1996).

As discussed in FDEP's Final Order of March 2, 1997, the ALJ's determination in this matter was flawed and in fact contradictory. Based upon EPA's review of the record, we concur with FDEP's finding in this Order that there was no substantiated evidence to support the assertion that the facility remained capable of co-firing petcoke during the 1970's when the facility fired fuel oil. In fact, the evidence, as well as the ALJ's findings themselves, support the contrary determination that the facility was "converted" from firing liquid fuel to firing solid fuel during the late 1970's, well after the 1975 date in the exemption invoked by FPC.

B. <u>The use of petroleum coke was not designed and built into Units 1 and 2</u>

The alternative fuels exemption is not contained in the Act, but was added to the PSD regulations in 1974 (the current version being codified in 1978) such that the definition of modification would be consistent with that used under the New Source Performance Standards (NSPS), as intended by Section 169(2)(C) of the Act. The stated intent of the NSPS exemption was to "eliminate inequities where equipment had been put into partial operation prior to the proposal of the standards," 36 FR 15,704 (August 3, 1971). The current NSPS regulations, at
40 C.F.R. § 60.14(e)(4), contain an analogue to the PSD alternatives fuel exemption at 40 C.F.R. § 52.21(b)(2)(ii)(e), which provides that the use of an alternative fuel or raw material shall not be considered a modification if:

> . . . the existing facility was designed to accommodate the alternative

> use. A facility shall be considered to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. . .

While the original NSPS exemption was changed slightly to allow for changes to the "original" design specification (40 FR 58,416 (December 16,1975)), the alterations did not change the intent of the exemption --- to grandfather voluntary fuel switches that a facility had designed for and built into its system prior to January 6, 1975.

The only fuels contemplated in the design and construction of Units 1 And 2 were coal and oil. Nothing in the design or construction documents for Units 1 and 2 suggests that FPC considered petcoke as a fuel for these units, nor does anything in those documents suggest that the design or construction was intended to accommodate the potential use of petcoke as a fuel. For example, the facility's 1971 operating permit application for Unit 2 required the source to identify "fuels" by type, and required that such identification "be specific." FPC identified only coal as the fuel type in this document and all other pre-1975 documents made available to EPA.

As discussed above, the purpose of the alternative fuels exemption was to eliminate any inequity faced by utilities which designed and constructed units to burn more than one fuel, but which were not burning all of those fuels as of January 6, 1975. For example, absent the exemption, a facility equipped to burn coal and oil, but which was only burning oil at the time the NSPS were adopted, would be subject to the NSPS and subsequently PSD review merely by switching back to coal. Therefore, EPA believes it is reasonable to interpret the alternative fuels exemption to apply only to fuels which were contemplated in the design and construction of a unit prior to January 6, 1975 and which the unit remained continuously able to burn. Units 1 and 2 do not meet these criteria, as they were never designed for petcoke and, through conversion to oil, lost the ability to burn solid fuel prior to January 6, 1975. Furthermore, in the burning of petcoke, FPC does not face the inequity remedied by the alternative fuels exemption.

To interpret this provision as allowing a facility to use "any" fuel that it could possibly burn prior to January 6, 1997, regardless of whether such fuels were originally contemplated or included in the original design, improperly expands the availability of the intended PSD exemption.[5] To do so would also establish an obvious inequity, neither intended nor likely to be overlooked by EPA in crafting the exemption, whereby

[5]Exceptions to the CAA are meant to be narrowly construed and provisions intended to "grandfather" existing facilities are not meant to constitute a perpetual immunity from all standards under the PSD program. Alabama Power Co. v. Costle, 636 f.2d 323, 354, 358, 400 (D.C. Cir, 1979).

facilities constructed prior to 1975 would be able to burn any number of fuels without complying with PSD or NSPS requirements and those constructed after this date would be subject to review and substantive requirements.

C. The proposed petroleum coke-coal fuel blend is not an "alternative fuel" within the meaning of the exemption.

As discussed in Alabama Power Co. v. Costle, the PSD exemption at 40 C.F.R. § 52.21(b)(2)(iii)(e) and the corresponding Florida provision at 62-212.400(2)(c)4 F.A.C. were intended to grandfather "voluntary fuel switches by emission sources which were designed to accommodate the alternative fuels prior to January 6, 1975." The provision was not intended to provide a loop-hole by which facilities may add various substances, such as waste products or waste fuels, to their primary fuels without being subject to PSD review. The Federal Register notices and background information documents that speak to this particular exemption only reference primary fuels, such as coal, oil and gas. At the time the alternative fuel exemption was promulgated, EPA contemplated "switches" between primary fuels. Therefore, it is a reasonable interpretation of the regulations to limit this exemption to primary fuels and not to apply the exemption to fuel additives that the facility was neither designed nor built to use as a primary fuel. FPC is currently burning coal as their primary fuel. It is EPA's determination that burning a 95% coal, 5% petcoke blend does not constitute a "switch" to an "alternative" fuel as intended by the exemption. Rather, the blending in of 5% petcoke is a change in the current method of operation that is subject to PSD review.

The above interpretations are consistent with FDEP's and EPA's longstanding interpretations of the "capable of accommodating" exemption. As you are aware, there are several EPA guidance memoranda, including a June 7, 1983 document from this office to Mr. Steve Smallwood of FDEP, that interpret the exemption to require that the facility be "designed" and continuously able to accommodate the use of a specified alternative fuel. This guidance clearly states:

> In order for a plant to be capable of accommodating coal, the company must show not only that the design (i.e., construction specifications) for the source contemplated the equipment, but also that the equipment actually was installed and still remains in existence. Otherwise, it cannot reasonably be concluded that the use of coal was "designed into the source."

FDEP's past implementation of its new source review regulations has also been consistent with this interpretation. According to FDEP's December 24, 1996 letter from C. H. Fancy, Bureau

of Air Regulation, to Mr. Brian Beals, EPA, requesting assistance with the FPC PSD applicability determination, FDEP had treated as major modifications, the use of a petroleum coke-coal blend in five coal-fired units in Florida for the purposes of PSD permitting as of that date. As documented in FDEP's letter: "in each case, the proposals have been treated as changes in method of operation to which PSD is applicable unless they are able to 'net out' by demonstrating that there will be no significant increases in PSD pollutants."

To remedy the above identified deficiency, the title V permit must include a compliance schedule, consistent with 40 C.F.R. § 70.5(c)(8)(iii), that requires FPC to obtain a PSD permit fulfilling State and federal PSD requirements and 40 C.F.R. § 70.6(c)(3). Progress reports referenced under 40 C.F.R. § 70.6(c)(4) must be required by the permit. Any additional requirements resulting from the PSD review, including requirements for control equipment and emission limitations, will have to be incorporated into the title V permit through permit modification. Alternatively, the State may concurrently issue proposed PSD and title V permits. As a third option, the State could issue a valid synthetic minor permit, limiting the emissions increase from the proposed change to less than the applicable PSD significance levels. As above, such conditions would need to be incorporated into the title V permit.

2. Periodic Monitoring - *Conditions A.14. and B.13.*, in conjunction with *Condition I.6.*, require that the source conduct annual testing for particulate matter whenever fuel oil is burned for more than 400 hours in the preceding year. The Statement of Basis states that this testing frequency "is justified by the low emission rate documented in previous emission tests while firing fuel oil" and that the "Department has determined that sources with emissions less than half of the effective standard shall test annually."

While EPA has in the past accepted this approach as adequate periodic monitoring for particulate matter, it has done so only for uncontrolled natural gas and fuel oil-fired units. The units addressed in *Conditions A.14. and B.13.*, primarily burn coal and use add-on control equipment (i.e., electrostatic precipitators) to comply with the applicable particulate matter standards. In order to provide reasonable assurance of compliance, the results of annual stack testing will have to be supplemented with additional monitoring. Furthermore, the results of an annual test alone would not constitute an adequate basis for the annual compliance certification that the facility is required to submit for these units in order to certify continuous compliance with the pound/hour particular matter limit.

The most common approach to addressing periodic monitoring for particulate emission limits on units with add-on controls is to establish either an opacity or a control device parameter indicator range that would provide evidence of proper control device operation. The primary goal of such monitoring is to provide reasonable assurance of compliance, and one way of achieving this goal is to use opacity data or control device operating parameter data from

previous successful compliance tests to identify a range of values that has corresponded to compliance in the past. Operating within the range of values identified in this manner would provide assurance that the control device is operating properly and would serve as the basis for an annual compliance certification. Depending upon the margin of compliance during the tests used to establish the opacity or control device parameter indicator range, going outside the range could represent either a period of time when an exceedance of the applicable standard is likely or it could represent a trigger for initiating corrective action to prevent an exceedance of the standard. In order to avoid any confusion regarding the consequences of going outside the indicator range, the permit should clearly state if doing so is evidence that a standard has been exceeded and should specify whether corrective action must be taken when a source operates outside the established indicator range.

3. Periodic Monitoring - *Conditions C.5. and D.4.* require that the source conduct Method 9 tests once annually for the fly ash handling system (Emission Units #006, #008, #009, and #010) and the bottom ash storage silo (Emission Unit #014), respectively. For units with control equipment (i.e., baghouses), this typically does not constitute adequate periodic monitoring to ensure continuous compliance with the visible emissions standards. It is also particularly important in this case to include adequate periodic monitoring with regard to the fly ash handling system since it has been limited to only 5 percent opacity in lieu of stack testing for particulate matter. Therefore, the permit needs to include provisions requiring that the source conduct qualitative observations of visible emissions on a daily basis (i.e., Method 22) and that Method 9 tests be conducted within 24 hours of any abnormal qualitative survey. As an alternative, since these units are controlled by baghouses, the source may opt to establish a parametric monitoring program. For instance, the permit could specify ranges for parameters, such as pressure drop, that would provide reasonable assurance that the source is in compliance with the applicable standards.

4. Periodic Monitoring - The material handling activities supporting the steam generating units (Emission Unit #016) are subject to a visible emissions limit of 20 percent opacity; however, the permit does not specify the frequency for testing. To certify compliance with the applicable opacity limit, the source should be required to conduct a Method 9 test at least once annually. To provide reasonable assurance of continuous compliance, the source needs to conduct (and record the results of) qualitative observations (i.e., Method 22) at least once daily with follow-up Method 9 tests within 24 hours of any abnormal visible emissions unless the statement of basis provides justification for reduced frequency.

5. Appropriate Averaging Times - *Conditions A.6., B.4.(a)(1), F.3., and G.2.* do not specify averaging times for the respective particulate matter emission limits. Because the stringency of

emission limits is a function of both magnitude and averaging time, appropriate averaging times must be added to the permit in order for the limits to be practicably enforceable. An approach that may be used to address this deficiency is to include a general condition in the permit stating that the averaging times for all specified emission standards are tied to or based on the run time of the test method(s) used for determining compliance.

6. Periodic Monitoring (Practical Enforceability) - *Conditions C.1. and D.1.* limit the mass flow rates of fly ash through the fly ash handling system and bottom ash through the bottom ash storage silo, respectively; however, the permit does not contain any provisions to practicably enforce such limits. The permit needs to include monitoring and/or recordkeeping requirements such as the maintenance of daily records of the mass throughputs for the affected units to provide reasonable assurance of compliance with the applicable limits.

7. Periodic Monitoring (Practical Enforceability) - *Conditions F.1. and G.1.* limit the volume flow rates of seawater through the cooling towers, Emission Units #013 and #015, respectively; however, the permit does not contain any provisions to practicably enforce such limits. The permit needs to include provisions requiring the source to monitor and record the flow of seawater through the cooling towers.

II General Comments

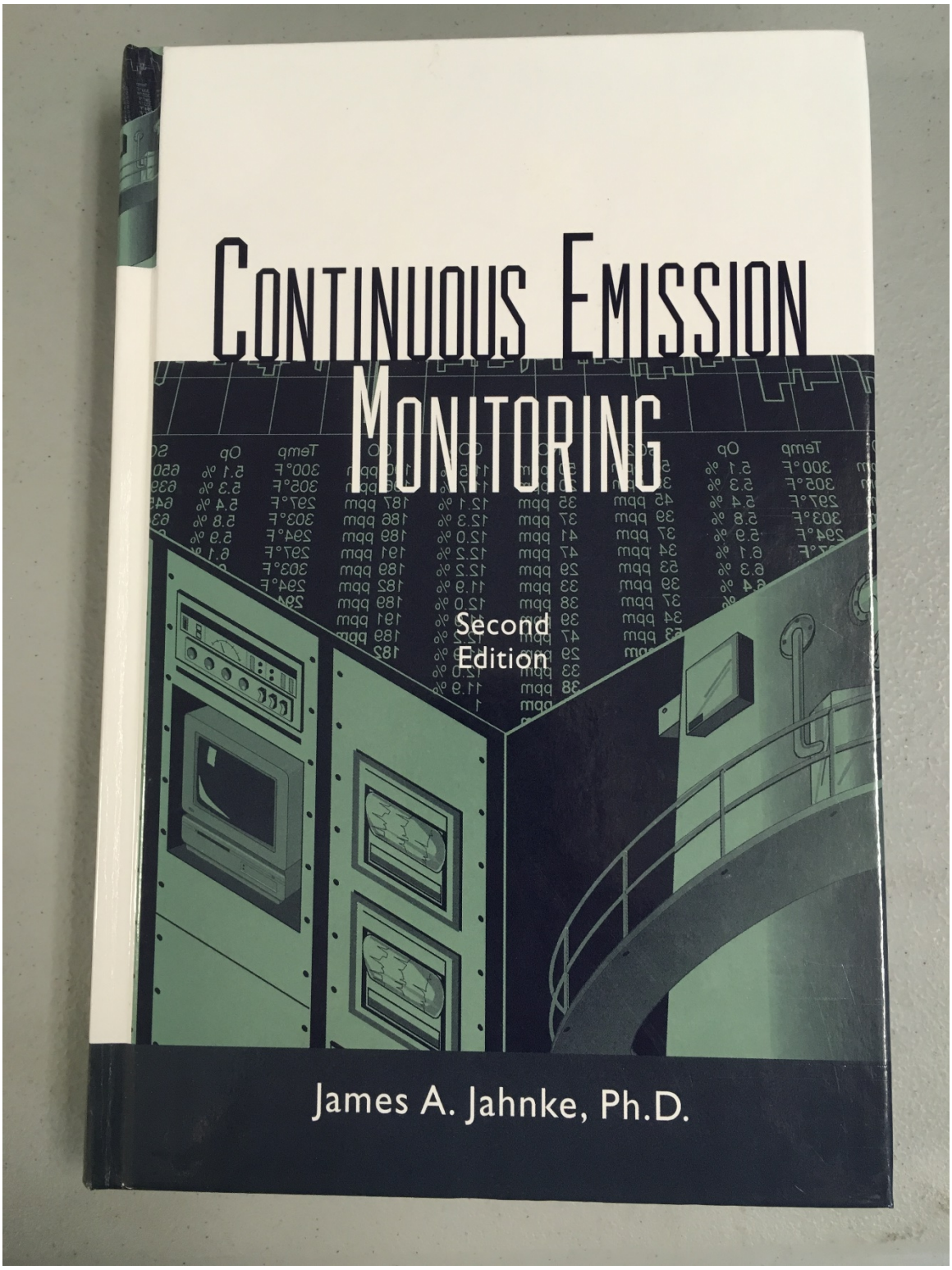
1. Compliance Certification - Facility-wide *Condition 11* of the permit should specifically reference the required components of Appendix TV-3, which lists the compliance certification requirements of 40 C.F.R. §70.6(c)(5)(iii), to ensure that complete certification information is submitted to EPA.

2. Acid Rain - The Phase II Acid Rain Application and Compliance Plan received on December 22, 1995, which are referenced as attachments made part of the permit (see page 1 of proposed permit), should also be referenced under Section IV, Subsection A.1.

3. Acid Rain - The NOx Early Election requirements and limits located in Subsection B (addressing Phase I Acid Rain) for Units 2, 4, and 5 of the Acid Rain part of the proposed title V permit should be moved to Subsection A (addressing Acid Rain, Phase II). Moving these requirements should clarify that FDEP is approving and incorporating the NOx Early Election requirements into the Phase II permit portion.

EXHIBIT 9

to Sierra Club Comments


CONTINUOUS EMISSION MONITORING
Second Edition
James A. Jahnke, Ph.D.

This book is printed on acid-free paper. ♾

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CONTINUOUS PARTICULATE MONITORING

Monitoring systems that measure particulate mass concentration on a continuing basis have been developed and are installed in many sources. Their application has been proven in Europe, where continuous particulate monitors are required for industrial boilers greater than 50 MW and for municipal and hazardous waste incinerators, as well as other facilities (Breton, 1990; Martin, 1996). In Europe, flue gas opacity is not regarded as a viable regulatory parameter. Instead, particulate emission standards are based in terms of mass concentration units of milligrams per cubic meter. Continuous particulate mass measurements are inherently more quantitative, enabling more precise control to be effected in plant operations.

In the United States, particulate mass emissions are measured only periodically by conducting a manual reference test, such as EPA Test Method 5 or 17. Due to the planning and preparations necessary for these manual methods, the source is usually notified prior to the actual testing. This lead time allows the source to optimize both operations and control equipment performance in order to pass the tests. Consequently, the tests may not be truly representative of actual source performance. This was understood by the U.S. Congress in the development of the 1990 Clean Air Act Amendments, where requirements for enhanced monitoring were established. Enhanced monitoring, translated into the Compliance Assurance Monitoring (CAM) rule, requires either parameter monitoring or the application of CEM systems to ensure compliance with emissions standards. Further, the U.S. EPA Office of Solid Waste has required that continuous particulate monitors be installed on hazardous waste incinerators (U.S. EPA, 1997) and has proposed Performance Specification

EXHIBIT 10

to Sierra Club Comments

NORTH COAST UNIFIED
AIR QUALITY MANAGEMENT DISTRICT
2300 Myrtle Avenue, Eureka, CA 95501
Phone: (707)443-3093 · Fax: (707) 443-3099



DOCKET
06-AFC-7
DATE APR 14 2008
RECD. APR 23 2008

TITLE V FEDERAL OPERATING PERMIT
NCUAQMD PERMIT TO OPERATE
AND
FINAL DETERMINATION OF COMPLIANCE

ATC PERMIT NO: 443-1

ISSUED TO:
Pacific Gas & Electric
1000 King Salmon Avenue
Eureka, CA 95503

PLANT SITE LOCATION:
Humboldt Bay Power Plant
1000 King Salmon Avenue
Eureka, CA

1st PERMIT ISSUED:
April 14, 2008

PERMIT EXPIRES:
See General Conditions

PERMIT HISTORY:

September 29, 2006	AFC
October 24, 2007	PDOC

RESPONSIBLE OFFICIAL:
Roy B. Willis
Plant Manager, HBPP Fossil
(707) 444-0700

CONTACT PERSON:
Terry Williams
Environmental Coordinator
(707) 444-0760

NATURE OF BUSINESS:
Commercial Electricity Generation

STANDARD INDUSTRIAL CLASSIFICATION (SIC):
4911

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PERMIT SUMMARY

This permit shall serve as a conditional Authority to Construct and temporary Permit to Operate, as well as the Prevention of Significant Deterioration pre-construction permit pursuant to North Coast Unified Air Quality Management (NCUAQMD) Rules and Regulations. Requirements identified in the permit as "Local Enforceable Only" are not enforceable by U.S. EPA, however, they are enforceable by the California Air Resources Board (CARB) and by the NCUAQMD.

The application for this air quality Authority to Construct and Temporary Permit to Operate has been evaluated for compliance with Federal, State, and NCUAQMD air quality rules and regulations. The following listed rules are the major rules that were found to be applicable at the time of this permit review, and based on the information submitted with the Title V permit application.

Federally Enforceable Rules & Regulations

Citation	Description	Rule Adoption Date
Rule 200	Permit Requirements	9-26-1997
Rule 220	New Source Review Standards	9-25-1998
Rule 230	Action on Applications	9-25-1998
Rule 240	Permit to Operate	9-26-1997
Rule 400	General Limitations	8-02-1978
Rule 410	Visible Emissions	3-5-1992
Rule 420	Particulate Matter	3-5-1992
Rule 430	Fugitive Dust	3-5-1992
Rule 440	Sulfur Oxide Emissions	3-5-1992
Rule 490	Federal New Source Performance Standards (NSPS)	9-27-1984
Reg 5 Rule 400	Procedures for Issuing Permits to Operate to Sources Subject to Title V of the Federal Clean Air Act Amendments of 1990	5-18-2001
NSPS	40 CFR 60 Subpart IIII	Promulgated 07-11-2006
NESHAP	40 CFR 63 Subpart ZZZZ	Promulgated 06-15-2004

Non-Federally Enforceable Rules & Regulations

Citation	Description	Recodified Rule Adoption Date
Regulation I, Rule 102	Permits	May 19, 2005
Regulation I, Rule 110	New Source Review Standards	May 19, 2005
Regulation I, Rule 103	Action on Applications	May 19, 2005
Regulation I, Rule 104.2	Visible Emissions	May 19, 2005

Regulation I, Rule 104.3	Particulate Matter	May 19, 2005
Regulation I, Rule 104.4	Fugitive Dust	May 19, 2005
Regulation I, Rule 104.5	Sulfur Oxide Emissions	May 19, 2005
Regulation I, Rule 104.11	Federal New Source Performance Standards (NSPS)	May 19, 2005
Regulation IV, Rule 400	Stationary Source Permit Fees	May 19, 2005
Regulation IV, Rule 406	Title V Fees	May 19, 2005
Regulation IV, Rule 407	Air Toxic "Hot Spots" (AB2588) Fees	May 19, 2005
Regulation IV, Rule 412	Major Source Assessment	May 19, 2005
Regulation V	Procedures for Issuing Permits to Operate for Sources Subject to Title V	May 19, 2005

Future changes in prohibitory rules may establish more stringent requirements that may, at the NCUAQMD level, supersede the conditions listed here. For Title V purposes, however, the federally enforceable requirements are those found in the Title V permit. Federally enforceable provisions of the Title V permit do not change until the Title V permit is revised.

RULES & REGULATIONS RECODIFICATION, EFFECT ON PERMIT

The NCUAQMD Rules and Regulations have been recodified, renumbered, and reorganized; and are in the process of being incorporated into the NCUAQMD State Implementation Plan. Once incorporated, the new regulatory references which are the same or similar to the then-superceded NCUAQMD rule citations, shall apply. The NCUAQMD reserves the right to revise the Title V permit to include the updated regulatory references.

FACILITY DESCRIPTION

PERMIT HISTORY

Application for Certification	September 29, 2006
PDOC	October 24, 2007
FDOC	April 8, 2008

EQUIPMENT DESCRIPTION

The plant will consist of ten Wärtsilä 18V50DF16.3 MW lean-burn reciprocating engines, equipped with selective catalytic reduction (SCR), oxidation catalyst, and associated support equipment including continuous emissions monitors. The primary fuel will be natural gas with diesel pilot injection, and the backup fuel will be diesel. The applicant will also install a diesel-fired emergency back-up generator and a diesel-fired fire pump. PG&E has identified and will be providing offsets for the project.

The NCUAQMD issued a Preliminary Determination of Compliance on October 24th

2007 and accepted public comment for 30 days pursuant to Rule 110 §8.4 through §8.6. After consideration of all comments received, the Air Pollution Control Officer has issued a Final Determination of Compliance (FDOC) pursuant to NCUAQMD Rule 110 §9.6.

PG&E currently operates a natural gas and fuel oil power plant on the same property as the proposed repower project. The existing plant consists of 2 steam turbine-generators, 52 and 53 MW, respectively, primarily fueled by natural gas, with No. 6 fuel oil used as a secondary fuel; and 2 mobile emergency power plants (MEPPs), consisting of diesel-fueled turbines that operate as backup units and peaker units. A non-operating 63 MW nuclear power plant also exists at the facility. The 52 MW boiler began operating in 1956 and the 53 MW boiler began operating in 1953. (AFC Section 1.0, pg. 1-1)

PG&E proposes to decommission the existing power plant and replace it with the ten 16.3 MW Wärtsilä reciprocating engines described above. The new engines will be subject to Best Available Control Technology (BACT) requirements as well as Prevention of Significant Deterioration (PSD).

EQUIPMENT OPERATING SCENARIOS

As a commercial power plant, market circumstances and demand will dictate the exact operation of the new reciprocating engines. However, the following general operating modes are projected to occur.

Base Load – The facility may be operated at maximum continuous output for as many hours per year as scheduled by load dispatch, and limited by operational constraints of the permit to operate (75% annual capacity factor). Normal operation of the plant will occur while the reciprocating engines are fired on natural gas with a diesel pilot: Firing on natural gas with diesel pilot is defined as “Natural Gas Mode” in this Permit.

Load Following – The facility may be operated to meet variable load requirements. The generation would be adjusted periodically to the load demand primarily by increasing or decreasing the number of reciprocating engine units in operation; and secondarily by raising or lowering the output of an individual reciprocating engine. Due to the modular nature of the project configuration, partial shutdown of the engine group will occur at certain times of any given day during any given year. This mode of operation could generally be expected during late evening and early morning hours when system demand may be low. As additional generating capacity becomes available in the foreseeable future, more frequent operation in this mode is anticipated. Several alternative energy projects have recently been proposed for the area which will compliment the modular design of this project.

Full Shutdown – This would occur if forced by equipment malfunction, fuel supply interruption, transmission line disconnect, natural disaster, or market conditions. The project will be the primary source of power generation for the north coast region for the next several years. As such, full shutdown for any length of time is not anticipated.

Secondary Fuel – The facility is also subject to periodic curtailment of the natural gas supply. In such a circumstance, the reciprocating engines may be fired on liquid fuel. The engines have the capability of switching fuel types without interruption to power generation. The number of hours of liquid fuel firing is limited by the ATC permit to a maximum of 1000 operating hours per year total for all of the engine units combined. Operation of the reciprocating engines while fired on 100% liquid fuel is defined as "Diesel Mode" in this Permit. The allowable liquid fuel types are limited to CARB Diesel, CARB Diesel with additives, and Alternative Liquid Fuel.

DEFINITIONS

As used in this Permit, the terms shall have the meaning set out herein.

a. **Acfm**: actual cubic feet per minute
b. **Alternative Liquid Fuel**: An alternative diesel fuel or CARB Diesel Fuel with fuel additives that meets the requirements of the California Air Resources Board Verification Procedure, as codified in Title 13, CCR, sections 2700-2710
c. **APCO:** the NCUAQMD Air Pollution Control Officer
d. **Calendar Day**: Any continuous 24-hour period beginning at 12:00 AM or 0000 hours
e. **California Air Resources Board (CARB) Diesel Fuel**: Any diesel fuel that is commonly or commercially known, sold, or represented by the supplier as diesel fuel No. 1-D or No. 2-D, pursuant to the specifications in ASTM D975-81, "Standard Specification for Diesel Fuel Oils," as modified in May 1982, which is incorporated herein by reference, and that meets the specifications defined in Title 13 CCR, sections 2281, 2282 and 2284
f. **CAM Plan**: Compliance Assurance Monitoring Plan, as defined in 40 CFR 64
g. **CARB**: the California Air Resources Board
h. **CEC CPM**: California Energy Commission Compliance Program Manager
i. **CEMS**: Continuous Emissions Monitoring System
j. **CFR**: the Code of Federal Regulations
k. **Commencement of Onsite Construction**: the commencement of a program of significant and continuous construction at the Facility or modification of the emissions unit(s) subject to this Permit
l. **Commissioning Activities**: All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the owner's engineer to ensure safe and reliable steady state operation of the reciprocating engines and associated electrical delivery systems
m. **Commissioning Period**: For each reciprocating engine considered separately, the time period that commences when a Reciprocating Engine is first fired. The period shall terminate when each individual reciprocating engine has successfully completed both performance and

compliance testing. The commissioning period shall not exceed 180 days under any circumstances.

n. **COMS**: Continuous Opacity Monitor
o. **Corrected Concentration**: The concentration of any pollutant (generally NO_x, CO, ROC, or NH_3) corrected to a standard stack gas oxygen concentration. For emission points S-1 through S-12, the standard stack gas oxygen concentration is 15% O_2 by volume on a dry basis
p. **Diesel Mode:** the firing of reciprocating engines S-1 through S-10 on CARB diesel, when the heat input from liquid fuel exceeds 0.8 MMBtu/hr, and when the engine operates under the theoretical Diesel cycle.
q. **Diesel Particulate Matter (DPM):** filterable particulate matter (PM) measured using EPA method 5
r. **Diesel Particulate Matter ATCM Emergency Use**: shall only pertain to engines S-11 and S-12 and shall mean providing electrical power or mechanical work during any of the following events and subject to the following conditions:
    i. The failure of loss of all or part of normal electrical power service or normal gas supply to the facility which is demonstrated by the Permittee to the NCUAQMD APCO's satisfaction to have been beyond the reasonable control of the Permittee.
    ii. The failure of the facility's internal power distribution system which is demonstrated by the owner or operator to the NCUAQMD APCO's satisfaction to have been beyond the reasonable control of the Permittee.
    iii. The pumping of water for fire suppression or protection.
s. **NCUAQMD**: North Coast Unified Air Quality Management NCUAQMD
t. **Dscfm**: dry standard cubic feet per minute
u. **Emergency:** operation arising from a sudden and reasonably unforeseeable event beyond the control of the permittee (e.g., an act of God) which causes the excess of a limitation under this permit and requires immediate and corrective action. An "emergency" does not include noncompliance as a result of improperly designed or installed equipment, lack of preventative maintenance, careless or improper operation, or operator error.
v. **EPA**: the United States Environmental Protection Agency
w. **Facility:** the site of the Humboldt Bay Repowering Project at HBPP
x. **Firing Hours:** Period of time during which fuel is flowing to a unit, measured in minutes divided by 60
y. **HBRP**: Humboldt Bay Repowering Project
z. **HBPP**: Existing Humboldt Bay Power Plant and applicable NCUAQMD permits.
aa. **Heat Input**: the energy (heat) input of the fuel combusted at the higher heating value (HHV) of the fuel
bb. **HHV**: Higher Heating Value
cc. **Hr**: one hour – a standard measurement of time
dd. **H_2S**: Hydrogen Sulfide

ee. **Lb**: pound – an English unit of measurement of weight and mass being equivalent to 7000 grains, 16 ounces, and 0.453 kilograms

ff. **Maintenance and Testing:** Operation of the reciprocating engines to (a) evaluate the ability of an engine or its supported equipment to perform during an emergency; or (b) facilitate the training of personnel on emergency activities; or (c) perform emissions testing, maintenance and operational testing, or safety-related testing as required by any government agency or by the manufacturer as a requirement of any law, regulation, rule, ordinance, standard, or contract

gg. **MMBtu**: million British thermal units

hh. **Natural Gas**: any mixture of gaseous hydrocarbons containing at least 80 percent methane by volume as determined by Standard Method ASTM D1945-64

ii. **Natural Gas Curtailment:** A reduction in the natural gas supply available to the Facility as specified below.

i. Curtailment directed by a regulatory agency, or automatically implemented by PG&E in accordance with procedures approved by a regulatory agency; and

ii. Curtailment cannot be related to fuel pricing (i.e., units will not be switched to Diesel fuel operation simply because gas prices are higher than Diesel prices).

jj. **Natural Gas Mode:** the firing of natural gas and CARB diesel or alternative liquid fuel in the engines where the diesel fuel or alternative liquid fuel is used solely for pilot injection, and the engine operates under the theoretical Otto cycle

kk. **NCUAQMD**: North Coast Unified Air Quality Management NCUAQMD

ll. **NFPA**: National Fire Protection Association

mm. **Normal Operations:** the operation of the Wärtsilä reciprocating engines identified in this permit, when firing in natural gas mode with diesel pilot injection, when not in startup, shutdown or malfunction mode

nn. **Notice**: unless otherwise stated, shall be in writing, sent postage prepaid, to the APCO and include all information required. Notice shall be sent to the APCO at the following address: 2300 Myrtle Ave., Eureka, CA 95501

oo. **Operational Minute:** a 60 second period when the engines are being fired. Each Operational Minute shall be designated as either “Natural Gas Mode” or “Diesel Mode”.

pp. **Operational Mode Transfer**: the switching of fuel mode while operating at engine loads greater than 50%. If the units are operated in Diesel Mode for one Operating Minute or more during any Clock Hour, the entire hour shall be considered as operation in Diesel Mode for purposes of determining compliance with emission limits. The sum of the Operational Minutes shall be used for determining compliance with hours of operation limitations

qq. **O_2**: Oxygen

rr. **Permittee:** the owner or operator identified on the Permit title page (PG&E)

ss. **PM**: Particulate Matter
tt. **Ppmvd:** parts per million, volumetric dry
uu. **Responsible Official:** person(s) who have direct supervisorial authority or control to affect operations of the equipment authorized pursuant to this Permit, and who have the ability to certify that a source complies with all applicable federal requirements and federally enforceable permit conditions as generally defined in NCUAQMD Rule 101 §1.245
vv. **Rolling 3-hour Period:** Any consecutive three-hour period, not including start-up or shut-down periods
ww. **ROC:** reactive organic carbon consistent with NCUAQMD Rule 101 §1.294 and HSC
xx. **Quarter:** calendar quarter, consisting of the following Q1 - January through March; Q2 - April through June; Q3 - July through September; Q4 - October through December
yy. **Shutdown Period:** The 30 minute period immediately prior to the termination of fuel flow to the reciprocating engine.
zz. **SO_2**: Sulfur Dioxide
aaa. **Startup Period:** The lesser of the first 60 minutes of continuous fuel flow to the reciprocating engine after fuel flow is initiated or the period of time from reciprocating engine fuel flow initiation until the reciprocating engine achieves two consecutive valid 15-minute average CEM data points in compliance with the emission concentration limits of conditions #100 and #102.
bbb. **VEE**: Visible Emissions Evaluation
ccc. **Year**: Any consecutive twelve-month period of time

FEDERALLY ENFORCEABLE GENERAL REQUIREMENTS

TITLE V PERMIT MODIFICATIONS AND RENEWAL

1. This Permit shall serve as the Prevention of Significant Deterioration preconstruction permit for the sources identified herein, and is issued pursuant to 40 CFR Part 70 and Regulation V of the Rules and Regulations of the North Coast Unified Air Quality Management District.
[NCUAQMD Reg 5 Rule 405(b)] [NCUAQMD Reg V Rule 502 Section 2.2 (5/19/05)] [40 CFR 70.5(a)(1)(iii)]

2. This permit shall be valid for a period not to exceed 545 days from the date of issuance. Upon completion of the construction and the commissioning phase for the internal reciprocating engines, the Permittee shall submit a Title V Permit to Operate application to the Air Pollution Control Officer.
NCUAQMD Reg 5 Rule 405(b)] [NCUAQMD Reg V Rule 502 Section 2.2 (5/19/05)] [40 CFR 70.5(a)(1)(iii)]

3. If modifications to the permit are necessary, the Permittee of the Title V source permitted herein shall submit to the Air Pollution Control Officer a complete Title V permit application for either an Administrative, Minor, or Significant Title V permit modification. The application shall not be submitted prior to receiving any required

preconstruction permit from the NCUAQMD. *[NCUAQMD Reg 5 Rule 405(c)] [NCUAQMD Reg V Rule 502 Section 2.3 (5/19/05)] [40 CFR 70.5(a)(1)(ii)]*

4. The Permittee shall submit to the Air Pollution Control Officer timely updates to the Title V application as new requirements become applicable to the source, and in no event less than quarterly (i.e., every three months).
   [40 CFR 70.5(b)]

5. A Permittee's responsible official shall promptly provide additional information in writing to the Air Pollution Control Officer upon discovery of submittal of any inaccurate information as part of the application or as a supplement thereto; or of any additional relevant facts previously omitted which are needed for accurate analysis of the application; and including inaccurate information known, or which should have been known or should be known, by the Permittee(s).
   [NCUAQMD Reg 5 Rule 420(c)] [NCUAQMD Reg V Rule 502 Sections 5.1, 5.3, 5.4 (5/19/05)] [40 CFR 70.5(a)(2) and (b)]

6. Upon written request of the Air Pollution Control Officer, the Permittee's responsible official shall supplement any complete application with additional information within the time frame specified by the Air Pollution Control Officer.
   [NCUAQMD Reg 5 Rule 420(b)] [NCUAQMD Reg V Rule 502 Section 5.2 (5/19/05)] [40 CFR 70.5(a)(2) and (b)]

7. PSD preconstruction permit expiration terminates the Permittee's right to operate the stationary sources itemized in this permit unless a timely and complete Title V permit application has been submitted, in which case the existing PSD preconstruction permit will remain in effect until the Title V permit has been issued or denied. In order to be considered timely, a complete Title V permit application must be submitted prior to the expiration of the PSD preconstruction permit.
   [NCUAQMD Reg 5 Rule 400(b)(c) and (d)] [NCUAQMD Reg V Rule 502 Sections 1.2, 1.3, and 1.4] [40 CFR 70.7(b) and (e)(2) (v)]

8. When submitting an application for a permit pursuant to Regulation 5, the Permittee's responsible official shall include the following information: A certification by a responsible official of all reports and other documents submitted for permit application; compliance progress reports at least every 6 months for, and submitted no later than 30 days after, the periods January 1st through June 30th and July 1st through December 31st of each year; statements on compliance status with any applicable enhanced monitoring; and annual compliance plans, no later than January 30th of each year, which shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document(s) are true, accurate, and complete.
   [NCUAQMD Reg 5 Rule 415(m)] [NCUAQMD Reg V Rule 502 Section 4.13 (5/19/05)] [40 CFR 70.5(c)(9) and (d)]

9. With the exception of acid rain units subject to Title IV of the Clean Air Act and solid waste incinerators subject to section 129(e) of the Clean Air Act, each permit issued

pursuant to NCUAQMD Regulation 5 to operate for any source shall include a condition for a fixed term not to exceed five years from the time of issuance. A permit to operate for an acid rain unit shall have a fixed permit term of five years. A permit to operate for a solid waste incinerator shall have a permit term of 12 years; however, the permit shall be reviewed at least every five years.
[NCUAQMD Reg 5 Rule 660] [NCUAQMD Reg V Rule 504 Section 11 (5/19/05)] [40 CFR 70.6(a)(2)]

COMPLIANCE

10. The Permittee shall comply with all conditions of the Title V permit.
[*NCUAQMD Reg 5 Rule 610(g) (1)] [NCUAQMD Reg V Rule 504 Section 2.7 (5/19/05)]*

11. Compliance with the conditions of this Title V permit shall be deemed compliance with all applicable requirements identified in the Title V permit.
[40 CFR 70.6(f)]

12. The Permittee may not assert or use as a defense, expressly, impliedly, or by operation of law or past practice, in any enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Title V permit.
[NCUAQMD Reg 5 Rule 610(g) (4)] [NCUAQMD Reg V Rule 504 Section 2.7.4 (5/19/05)]

13. This Title V permit may be modified, revoked, reopened, and reissued or terminated for cause.
[NCUAQMD Reg 5 Rule 570(a) and (b)] [NCUAQMD Reg V Rule 503 Section 9 (5/19/05)]

14. The Permittee shall furnish to the Air Pollution Control Officer, within 10 (ten) days of the request, any information that the Air Pollution Control Officer may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit; or to determine compliance with this Title V permit. Upon request, the permittee shall also furnish to the Air Pollution Control Officer copies of records required to be kept by conditions of this permit. For information claimed to be confidential, the permittee may furnish such records directly to the EPA along with a claim of confidentiality. *[40 CFR 70.6(a)(6)(v)]*

15. Noncompliance with any federally enforceable requirement in this Title V permit is grounds for Title V permit termination, revocation and reissuance, modification, enforcement action, or denial of the Title V permit renewal application.
[NCUAQMD Reg 5 Rule 610(g) (3)] [NCUAQMD Reg V Rule 504 Section 2.7.3 (5/19/05)]

16. A pending Title V permit action (e.g. a proposed permit revision) or notification of anticipated noncompliance does not stay any permit condition. *[NCUAQMD Reg 5 Rule 610(g) (5)] [NCUAQMD Reg V Rule 504 Section 2.7.5 (5/19/05)]*

17. This Title V permit does not convey any property rights of any sort or any exclusive privilege.
[NCUAQMD Reg 5 Rule 610(g) (2)] [NCUAQMD Reg V Rule 504 Section 2.7.2 (5/19/05)]

18. Upon presentation of credentials and other documents as may be required by law, the Permittee shall allow the Air Pollution Control Officer or an authorized representative to perform all of the following:
    A. Enter upon the stationary source's premises where this source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;
    B. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this Title V permit;
    C. Inspect at reasonable times, the stationary source, equipment (including monitoring and air pollution control equipment), practices and operations regulated or required under this Title V permit; and
    D. As authorized by the Federal Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of ensuring compliance with the Title V permit conditions or applicable federal requirements.

    [NCUAQMD Reg 5 Rule 610(e)] [NCUAQMD Reg V Rule 504 Section 2.5 (5/19/05)]

REPORTS AND RECORDKEEPING

19. Monitoring Reports
    A. The Permittee shall submit to the Air Pollution Control Officer at least once every six months, unless required more frequently by an applicable requirement, reports of all required monitoring set out in this Title V permit.
    B. The reporting periods for this permit shall be for the six month periods January 1st through June 30th and July 1st through December 31st. The reports shall be submitted by July 30th and January 30th of each year respectively.
    C. Any and all instances of deviations from Title V permit conditions must be clearly identified in such reports. All required reports must be certified by the responsible official and shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

    [NCUAQMD Reg 5 Rules 460 and 625] [NCUAQMD Reg V Rule 502 Section 11 and Rule 504 Section 5 and (5/19/05)] [40 CFR 70.6(a)(3)(ii) and (iii)]

20. Compliance Reports
    A. The Permittee shall submit to the Air Pollution Control Officer and to U.S. EPA (Air-3, U.S. EPA, Region IX) on an annual basis, unless required more frequently by additional applicable federal requirements, a certification of compliance by the Permittee's responsible official with all terms and conditions contained in the Title V permit, including emission limitations, standards and work practices.
    B. The reporting period for this permit shall be January 1st through December 31st. The report shall be submitted by January 30th of each year. The initial report shall be for the period January 1st 2009 through December 31st 2009 and shall be submitted by March 1st 2010.

C. All required reports must be certified by the responsible official and shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.
D. The compliance certification shall include the following:
   i. The identification of each term or condition of the Title V permit that is the basis of the certification.
   ii. The method(s) used for determining the compliance status of the source, currently and over the reporting period, and whether such method(s) provides continuous or intermittent data.
   iii. The status of compliance with the terms and conditions of the Title V permit for the period covered by the certification, based on the method designated in Section D (ii) of this condition.
   iv. Such other facts as the Air Pollution Control Officer may require in order to determine the compliance status of the source.
   v. A method for monitoring the compliance of the stationary source with its emissions limitations, standards and work practices.

[NCUAQMD Reg 5 Rule 650] [NCUAQMD Reg V Rule 504 Section 10 (5/19/05)] [40 CFR 70.6(b)(5)]

21. The Permittee shall report within 24 hours of detection any deviation from a federally enforceable Title V permit condition not attributable to an emergency. In order to fulfill the reporting requirement of this condition, the permittee shall notify the Air Pollution Control Officer by telephone followed by a written statement describing the nature of the deviation from the federally enforceable permit condition.
[NCUAQMD Reg 5 Rule 625] [NCUAQMD Reg V Rule 504 Section 5 (5/19/05)] [40 CFR 70.6(a)(3)(iii)]

22. All monitoring data and support information required by a federally enforceable applicable requirement must be kept by the stationary source for a period of 5 years from the date of the monitoring sample, measurement, report or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the federally enforceable applicable requirement in the Title V permit.
[NCUAQMD Reg 5 Rules 455 and 615] [NCUAQMD Reg V Rule 502 Section 10 and Rule 504 Section 3 (5/19/05)] [40 CFR 70.6(a)(3)(ii)]

PUBLIC NUISANCE

23. The Permittee(s) shall not discharge such quantities of air contaminants or other material which cause injury, detriment, nuisance or annoyance to any considerable number of persons or to the public or which endanger the comfort, repose, health or safety of any such persons or the public or which cause or have a natural tendency to cause injury or damage to business or property.
[NCUAQMD Reg 1 Rule 400(a)]

VISIBLE EMISSIONS

24. The owner, operator or Permittee of this Title V source shall not discharge into the atmosphere from any single source of emission whatsoever any air contaminant, other than uncombined water vapor, for a period or periods aggregating more than three minutes in any one hour which is:
    A. As dark or darker in shade as that designated No. 2 (6-minute average), on the Ringelmann Chart, as published by the United States Bureau of Mines, or
    B. Of such opacity as to obscure a human observer's view, or a certified calibrated in-stack opacity monitoring system to a degree equal to or greater than No. 2 on the Ringelmann Chart.

    [NCUAQMD Rule 410] [NCUAQMD Reg I Rule 104 Section 2 (5/19/05)]

PARTICULATE MATTER

25. A. General Combustion Sources
    The Permittee of this Title V source shall not discharge particulate matter into the atmosphere from any combustion source in excess of 0.46 grams per standard cubic meter (0.20 grains per standard cubic foot) of exhaust gas, calculated to 12 percent carbon dioxide; or in excess of the limitations of NSPS Rule 490, as applicable.
    B. Steam Generating Units
    The Permittee of this Title V source shall not discharge particulate matter into the atmosphere from any steam generating unit, installed or modified after July 1, 1976, in excess of 0.23 grams per standard cubic meter (0.10 grains per standard cubic foot) of exhaust gas, calculated to 12 percent carbon dioxide; or in excess of the limitations of NSPS Rule 490.
    C. Steam Generating Utility Power Plants
    Notwithstanding the limitations set out above, no steam generating power plants which produce electric power for sale to any public utility shall discharge particulate matter into the atmosphere in excess of 0.10 pounds per million BTU heat input or any other specific applicable permit limitation, whichever is the more restrictive emission condition.
    D. Non-Combustion Sources
    The Permittee of this Title V source shall not discharge particulate matter into the atmosphere from any non-combustion source in excess of 0.46 grams per actual cubic meter (0.20 grains per cubic foot) of exhaust gas or in total quantities in excess of the maximum allowable process weight rate as follows:

TABLE I

ALLOWABLE RATE OF EMISSION BASED ON PROCESS WEIGHT RATE					
Process Weight Rate		Rate of Emission	Process Weight Rate		Rate of Emission
Lb/Hr	Kg/Hr	Lb/Hr	Lb/Hr	Kg/Hr	Lb/Hr
100	45	0.55	6,000	2,720	8.6
200	92	0.88	7,000	3,380	9.5
400	183	1.4	8,000	3,680	10.4
600	275	1.83	9,000	4,134	11.2
800	377	2.22	10,000	4,540	12.0
1,000	454	2.58	12,000	5,460	13.6
1,500	681	3.38	16,000	7,260	16.5
2,000	920	4.1	18,000	8,220	17.9
2,500	1,147	4.76	20,000	9,070	19.2
3,000	1,362	5.38	30,000	13,600	25.2
3,500	1,690	5.96	40,000	18,100	30.5
4,000	1,840	6.52	50,000	22,700	35.4
5,000	2,300	7.58	60,000	27,200	40.0

Where the process weight per hour is between two listed figures, such process weight and maximum allowable particulate emission per hour shall be interpolated linearly. The total process weight of all similar process operations located at a single plant or of similar multiple plants located on a single premise, shall be used for determining the maximum allowable particulate emission from the combination of such operations.

[NCUAQMD Rule 420] [NCUAQMD Reg I Rule 104 (5/19/05)]

26. The Permittee of this Title V source shall not handle, transport or store or allow open storage of materials in such a manner which allows or has the potential to allow unnecessary amounts of particulate matter to become airborne. Reasonable precautions shall be taken to prevent particulate matter from becoming airborne, including, but not limited to, the following:
    A. Covering open bodied trucks when used for transporting materials likely to give rise to airborne dust.
    B. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials. Containment methods can be employed during sandblasting and other similar operations.
    C. Conduct agricultural practices in such a manner as to minimize the creation of airborne dust.
    D. The use of water or approved dust surfactants for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads or the clearing of land.

E. The application of asphalt, oil, water or suitable chemicals on dirt roads, materials stockpiles, and other surfaces which can give rise to airborne dusts.
F. The paving of roadways and their maintenance in a clean condition.
G. The prompt removal of earth or other material from paved streets onto which earth or other material has been transported by trucking or earth moving equipment, erosion by water, or other means.

[NCUAQMD Rule 430] [NCUAQMD Reg I Rule 104 Section 4 (5/19/05)]

SULFUR COMPOUNDS

27. The owner(s), operator(s) or Permittee(s) of this Title V source shall not discharge into the atmosphere from any single source of emissions whatsoever sulfur oxides, calculated as sulfur dioxide (SO2) in excess of 1,000 ppm; or in excess of the specific source emission limitations of Federal New Source Performance Standards, as applicable.

[NCUAQMD Rule 440] [NCUAQMD Reg I Rule 104 Section 5 (5/19/05)]

OPEN BURNING

28. The Permittee of this Title V source shall not ignite or cause to be ignited or suffer, allow or maintain any open outdoor fire for the disposal of rubber, petroleum or plastic wastes, demolition debris, tires, tar paper, wood waste, asphalt shingles, linoleum, cloth, household garbage or other combustible refuse; or for metal salvage or burning of motor vehicle bodies No other open burning shall occur without the owner, operator(s) or Permittee having first obtained a Coordinated Authorized Burn Permit from the Air Pollution Control Officer.

[NCUAQMD Reg 2 Rules 200 & 201]

EQUIPMENT BREAKDOWNS

29. The Permittee shall comply with the emergency provisions contained in all applicable federal requirements.

A. Within two weeks of an emergency event, the owner(s), operator(s) or Permittee's responsible official shall submit to the Air Pollution Control Officer a signed contemporaneous log or other relevant evidence which demonstrates that:

i. An emergency occurred.
ii. Identification of the cause(s) of the emergency.
iii. The facility was being properly operated at the time of the emergency.
iv. Identification of each and every step taken to minimize the emissions resulting from the emergency.
v. Within two working days of the emergency event, the permittee shall notify the Air Pollution Control Officer with a description of the emergency and any mitigating or corrective actions taken.

C. The Permittee has the burden of proof to establish that an emergency occurred in any enforcement proceeding.

[NCUAQMD Reg 5 Rule 450]

TITLE VI REQUIREMENTS (OZONE DEPLETING SUBSTANCES)

30. The Permittee of this Title V source allowing or causing the opening of appliances containing CFCs for maintenance, service, repair, or disposal must comply with the required practices set out in and pursuant to 40 CFR 82.156.
[40 CFR 82 Subpart F]

31. Equipment used during the maintenance, service, repair, or disposal of appliances containing CFCs shall comply with the standards for recycling and recovery equipment set out in and pursuant to 40 CFR 82.158.
[40 CFR 82 Subpart F]

32. The Permittee and its contractors and agents performing maintenance, service, repair or disposal of appliances containing CFCs must be certified by an approved technician certification program set out in and pursuant to 40 CFR 82.161.
[40 CFR 82 Subpart F]

ASBESTOS

33. The Permittee of this Title V source shall comply with the standards of 40 CFR 61 Subpart M which regulates demolition and renovation activities pertaining to asbestos materials.

PAYMENT OF FEES

34. The Permittee of this Title V source shall pay an annual permit fee and other fees as required in accordance with NCUAQMD Rule 300. Failure to pay these fees by the dates due will result in immediate suspension of this Title V Permit to Operate effective on the date the fees were due, and on notification by the Air Pollution Control Officer of such suspension. Operation without an effective Title V permit subjects the owner(s), operator(s) and Permittee(s) to potential enforcement action by the NCUAQMD and the U.S. EPA pursuant to Section 502(a) of the Clean Air Act as amended in 1990.
[NCUAQMD Reg 5 Rule 670]

ACCIDENTAL RELEASES

35. If subject to Section 112(r) of the CAA and 40 CFR Part 68, the Permittee(s) of this Title V permit shall register and submit to the U.S. EPA the required data related to the risk management plan (RMP) for reducing the probability of accidental releases of any regulated substances listed pursuant to Section 112(r) (3) of the CAA as amended in 68.130. The list of substances, threshold quantities and accident prevention regulations promulgated under Part 68 do not limit in any way the general duty provisions under Section 112(r)(1).
[40 CFR Part 68]

36. If subject to Section 112(r) of the CAA and 40 CFR Part 68, the Permittee shall comply with the requirements of 40 CFR Part 68 no later than the latest of the following dates as provided in 40 CFR 68.10(a):
A. June 21, 1999,
B. Three years after the date on which a regulated substance is first listed under 68.130, or

C. The date on which a regulated substance is first present above a threshold quantity in a process.
[40 CFR Part 68]

37. If subject to Section 112(r) of the CAA and 40 CFR Part 68, the Permittee(s) shall submit any additional relevant information requested by any regulatory agency necessary to ensure compliance with the requirements of 40 CFR Part 68.
[40 CFR Part 68]

38. If subject to Section 112(r) of the CAA and 40 CFR Part 68, the Permittee(s) shall annually certify compliance with all applicable requirements of Section 112(r) as part of the annual compliance certification. This annual compliance certification shall be submitted and received no later than January 30th of each year.
[40 CFR Part 68]

CONDITIONAL TRANSFER OF OWNERSHIP

39. In the event of any changes in control or ownership of these facilities, this permit together with its terms and conditions shall be binding on all subsequent owners and operators. The Permittee shall notify the succeeding owner and operator of the existence of this permit and its conditions by letter, a copy of which shall be forwarded to the NCUAQMD, and which shall identify the exact effective date of the transfer of ownership.

The new owner(s) and operator(s) of this Title V source shall notify the Air Pollution Control Officer within 30 (thirty) days of the transfer of ownership and which notification shall include a certification by the responsible party that the Title V facility operations are to be operated in the same operational parameters as set out herein, and as before the transfer of ownership.

Any permit or written authorization issued pursuant herein shall not be transferable, by operation of law or otherwise, from one location to another, or from one person to another, unless such transfer occurs as a condition of this permit or as a modification to the permit and with written notification to the Air Pollution Control Officer within 30 (thirty) days of transfer of ownership.
[NCUAQMD Rule 240]

SEVERABILITY

40. If any term or condition of this permit, for any reason, be adjudged by a court of competent jurisdiction to be invalid, such judgment shall not affect or invalidate the remainder of this permit. These permit conditions are enforceable individually and severally.
[NCUAQMD Reg 5 Rule 610(h)] [40 CFR 60.6(b)(5)]

LOCAL ENFORCEABLE ONLY, GENERAL REQUIREMENTS

APPLICABILITY

41. The requirements outlined in this section are non-federally enforceable local permit

requirements. *[NCUAQMD Rule 102]*

42. The Permittee of this Title V source shall not cause or permit the construction or modification of any new source of air contaminants or modifications to an existing source, either minor or major, without first having obtained an Authority to Construct (ATC) permit from the Air Pollution Control Officer.

43. This permit is effective only upon payment of the initial permit fees set out in NCUAQMD Rules and Regulations.

ADMINISTRATION

44. This Permit is issued pursuant to California Health and Safety Code Section 42300. Commencement of any act or operation authorized by this Permit shall be conclusively deemed to be acceptance of all terms and conditions contained herein.

45. The Permittee shall comply with all conditions of this permit. Any violation of any condition of this Permit is a violation of NCUAQMD Rules and Regulations, and California State Law. [*NCUAQMD Rule 105 §1.0*]

46. The Permit Conditions shall be liberally construed for the protection of the health, safety and welfare of the people of the NCUAQMD. [*NCUAQMD Rule 100 §6.3; Rule 102 §5.0]*

47. The NCUAQMD Rules and Regulations may be superseded or revised by the NCUAQMD Board with notice as required by state law. It is Permittee's responsibility to stay current with Rules and Regulations governing its business. The Permittee is therefore expected to comply with all applicable Rules and Regulations. [*NCUAQMD Rule 100 §6.0; Rule 105 §1.0*]

48. Permit requirements apply to the facility owner and/or operator(s) and any contractor(s) or subcontractor(s) performing any activity authorized under this Permit. Any person(s) including contractor(s), subcontractor(s), not in compliance with the applicable permit requirements are in violation of State and Local laws and subject to appropriate civil and criminal penalties. The facility owner and/operator, and all contractor(s) or subcontractor(s) are strictly liable for the actions and violations of their employee(s). A violation committed by a contractor(s) or subcontractor(s) shall be considered a violation by the facility owner(s) and/or operator(s), and is also a violation by the contractor(s) and/or any subcontractor(s). [*NCUAQMD Rule 105 §5.0*]

49. Changes in plans, specifications, and other representations proposed in the application documents shall not be made if they will increase the discharge of emissions or cause a change in the method of control of emissions or in the character of emissions. Any proposed changes, regardless of emissions consequence, shall be submitted as a modification to this Permit. No modification shall be made prior to issuance of a permit revision for such modification. [*NCUAQMD Rule 102*]

50. Knowing and willful misrepresentation of a material fact in the application for the Permit, or failure to comply with any condition of the Permit, or of the NCUAQMD Rules and Regulations, or any state or federal law, shall be grounds for revocation of this Permit. [*NCUAQMD Rule 102*]

51. Permittee shall not construct, erect, modify, operate, or use any equipment which conceals the emission of an air contaminant, which would otherwise constitute a violation of the limitations of this Permit. [*NCUAQMD Rule 104 §1.2*]

52. This Permit does not convey any property rights of any sort, or any exclusive privilege.

53. The "Right of Entry", as delineated in NCUAQMD Rule 109 §1.0 and California Health and Safety Code Section 41510 of Division 26, shall apply at all times. Failure to grant immediate access to NCUAQMD, CARB, or other authorized personnel shall be grounds for permit suspension or revocation.

54. The APCO reserves the right to amend this Permit in order to ensure compliance with all applicable Federal, State and Local laws, Rules and Regulations or to mitigate or abate any public nuisance. Such amendments may include requirements for additional operating conditions, testing, data collection, reporting and other conditions deemed necessary by the APCO.

55. In the event that two or more conditions may apply, and such conditions both cannot apply without conflict, the condition(s) most protective of the environment and the public health and safety shall prevail. In the event that a condition(s) of the Permit and a requirement of a Federal, State or Local law, rule or regulation may also apply, and both cannot apply without conflict, the requirements most protective of the environment and the public health and safety shall prevail. [*NCUAQMD Rule 100 §6.3; NCUAQMD Rule 102 §5.0*]

56. If any provision or condition of this Permit is found invalid by a court of competent jurisdiction, such finding shall not affect the validity or enforcement of the remaining provisions. [*NCUAQMD Rule 102 §5.0*]

57. This Permit shall be posted in a conspicuous location at the site and shall be made available to NCUAQMD representatives upon request. [*NCUAQMD Rule 102 §8.0*]

58. The Permittee shall pay an annual permit fee and other fees as required in accordance with NCUAQMD Regulation IV. Failure to pay these fees will result in the forfeiture of this Permit. Operation without a permit subjects the source to potential enforcement action by the NCUAQMD. In the event of facility closure or change of ownership or responsibility, the new owner or operator shall be assessed and shall pay any unpaid fees. [*NCUAQMD Regulation IV - Fees*]

59. This Permit is not transferable from either one location to another, from one piece of equipment to another, or from one person to another, except as provided herein. In

the event of any change in control or ownership of the subject facility, the Permittee shall notify the succeeding owner of this Permit and its conditions; and shall notify the NCUAQMD of the change in control or ownership within fifteen (15) days of that change. [*NCUAQMD Rule 400 §5.0*]

60. A request for Transfer of Ownership of this Permit shall be submitted to the APCO prior to commencing any operation of the subject equipment and/or operations by any owner(s) and/or operator(s) not otherwise identified in this Permit. Failure to file the Transfer of Ownership constitutes a separate and independent violation, and is cause for voiding this Permit. The burden of applying for a Transfer of Ownership is on the new owner(s) and/or operator(s). Any Permit transfer authorized pursuant to a transfer of ownership request shall contain the same conditions as this Permit. [*NCUAQMD Rule 400 §5.0; Rule 102 §5.0*]

61. For purposes of this Permit, the terms identified in the Definition Section shall have the meaning set out therein. [NCUAQMD Rule 102 §5.0]

EMISSIONS & OPERATION

62. This Permit does not authorize the emission of air contaminants in excess of those allowed by the Federal Clean Air Act, California Health and Safety Code or the Rules and Regulations of the NCUAQMD. This Permit shall not be considered as permission to violate existing laws, ordinances, regulation or statutes of other governmental agencies.

63. Permittee shall not discharge such quantities of air contaminants or other material which cause injury, detriment, nuisance or annoyance to any considerable number of persons or to the public or which endanger the comfort, repose, health or safety of any such persons or the public or which cause or have a natural tendency to cause injury or damage to business or property. [*CH&S §41700; NCUAQMD Rule 104 §1.1*]

64. Permittee shall not discharge into the atmosphere from any source whatsoever any air contaminant for a period or periods aggregating more than three (3) minutes in any one hour which is as dark or darker in shade as that designated as No. 2 on the Ringelmann Chart, as published by the United States Bureau of Mines; or of such opacity as to obscure an observer's view to a degree equal to or greater than Ringelmann 2 or forty (40) percent opacity. [*CH&S §41701; NCUAQMD Rule 104 §2.0*]

65. The handling, transporting, or open storage of material in such a manner which allows unnecessary amounts of particulate matter to become airborne shall not be permitted. Reasonable precautions shall be taken to prevent particulate matter from becoming airborne. [*NCUAQMD Rule 104 §4.0*]

66. All equipment regulated by this Permit shall at all times be maintained in good working order and shall be operated as efficiently as possible so as to ensure compliance with all applicable emission limits. For purposes of compliance with this

requirement, good working order, efficient operation, and proper maintenance shall mean the implementation of all protocols, procedures, and activities recommended by the device manufacturer or those required by this Permit. [*NCUAQMD Rule 102 §5.0*]

RECORDS & TRAINING

67. The Permittee shall provide training and instruction to all contractor(s), subcontractor(s), and employee(s). Training shall include the identification of all the requirements contained within this Permit, and the appropriate method to be used to comply with the permit conditions. Training shall occur prior to any of the contractor(s), subcontractor(s), or employee(s) constructing or operating equipment authorized by this permit. Records documenting the persons receiving instruction and the instruction materials shall be made available to the APCO upon request. [*NCUAQMD Rule 105 §5.0*]

68. Permittee shall furnish to the APCO, within a reasonable time, any information that the NCUAQMD may request to determine compliance with this Permit or whether cause exists for modifying, revoking and reissuing, or terminating this Permit. Upon request, Permittee shall also furnish to the NCUAQMD copies of records required to be kept by this Permit. [*CH&S §42303; NCUAQMD Rule 103 §6.0, Rule 102 §5.0*]

PERMIT TERM

69. This Permit is issued pursuant to NCUAQMD Rule 110 Section 9 and shall only become effective after a Final Determination of Compliance has been issued by the APCO pursuant to NCUAQMD Rule 110 §9.6.

70. The authorization for equipment installation and construction activities identified in this Permit shall expire no more than 545 days from date of issue. [*NCUAQMD Rule 102 §5.0*]

71. Once the subject equipment has been constructed in compliance with the conditions of this permit, this Authority to Construct Permit shall serve as a Temporary Permit to Operate for a period not to exceed one hundred and eighty (180) days of operation. Should the need arise, the Temporary Permit to Operate may be extended by the APCO for up to an additional ninety (90) days for good cause shown. The burden of proof lies with the Permittee to demonstrate good cause for such action. [*CH&SC §42301.1; NCUAQMD Rule 102 §2.0*]

FEDERALLY ENFORCEABLE, EQUIPMENT SPECIFIC REQUIREMENTS

The information specified under this section is enforceable collectively and severally by the NCUAQMD, U.S. EPA, and the public.

Authorized Equipment

72. The Permittee shall install and construct the project as described in Authority To Construct application September 29th 2006 and its series of amendments ending with the most recent submittal of February 27th 2008. Should discrepancies or contradictions exist between the application and this Permit, the provisions of this Permit shall prevail. The specific components authorized are listed in Table 1.0 and Table 2.0 below. For each of the reciprocating internal combustion engines S-1 through S-10, both a Selective Catalytic Reduction system (SCR) and an oxidation catalyst shall be designated "A-(engine number) SCR" and "B-(engine number) oxidation catalyst respectively". *[NCUAQMD Rule 504 §2.1]*

Table 1.0 Authorized Emission Devices

Unit No.	Equipment	Nominal Size
S-1	Wärtsilä 18V50DF Dual Fuel Reciprocating Engine #1, equipped with lean burn technology, abated by A-1 SCR and B-1oxidation catalyst	148.9 MMBtu/hr 16.3 MW 22,931 BHp
S-2	Wärtsilä 18V50DF Dual Fuel Reciprocating Engine #2, equipped with lean burn technology, abated by A-2 SCR and B-2 oxidation catalyst	148.9 MMBtu/hr 16.3 MW 22,931 BHp
S-3	Wärtsilä 18V50DF Dual Fuel Reciprocating Engine #3, equipped with lean burn technology, abated by A-3 SCR and B-3 oxidation catalyst	148.9 MMBtu/hr 16.3 MW 22,931 BHp
S-4	Wärtsilä 18V50DF Dual Fuel Reciprocating Engine #4, equipped with lean burn technology, abated by A-4 SCR and B-4 oxidation catalyst	148.9 MMBtu/hr 16.3 MW 22,931 BHp
S-5	Wärtsilä 18V50DF Dual Fuel Reciprocating Engine #5, equipped with lean burn technology, abated by A-5 SCR and B-5 oxidation catalyst	148.9 MMBtu/hr 16.3 MW 22,931 BHp
S-6	Wärtsilä 18V50DF Dual Fuel Reciprocating Engine #6, equipped with lean burn technology, abated by A-6 SCR and B-6 oxidation catalyst	148.9 MMBtu/hr 16.3 MW 22,931 BHp
S-7	Wärtsilä 18V50DF Dual Fuel Reciprocating Engine #7, equipped with lean burn technology, abated by A-7 SCR and B-7 oxidation catalyst	148.9 MMBtu/hr 16.3 MW 22,931 BHp
S-8	Wärtsilä 18V50DF Dual Fuel Reciprocating Engine #8, equipped with lean burn technology, abated by A-8 SCR and B-8 oxidation catalyst	148.9 MMBtu/hr 16.3 MW 22,931 BHp
S-9	Wärtsilä 18V50DF Dual Fuel Reciprocating Engine #9, equipped with lean burn technology, abated by A-9 SCR and B-9 oxidation catalyst	148.9 MMBtu/hr 16.3 MW 22,931 BHp
S-10	Wärtsilä 18V50DF Dual Fuel Reciprocating Engine #10, equipped with lean burn technology, abated by A-10 SCR and B-10 oxidation catalyst	148.9 MMBtu/hr 16.3 MW 22,931 BHp
S-11	Caterpillar DM8149 (or equivalent) Diesel-fired Emergency IC Engine powering a 350kW electrical generator	469 HP
S-12	Clarke/John Deere JU6H-UF50 (or equivalent) Diesel-fired Emergency IC Engine powering a fire water pump	210 HP

Table 2.0 Authorized Control Devices

Control Equipment	Manufacturer	Model	Specifications
Oxidation Catalyst	HUG Engineering (or equivalent)	OCT-0806-040-0062/450 (or equivalent)	Catalyst: Platinum Reactor Temperature: 608 ˚F to 908 ˚F Outlet Temperature: 608 ˚F to 908 ˚F Max Flow: 143,000 acfm Control Efficiency: 13ppmvd CO @15%O_2 while in NG Mode; 20ppmvd CO @15%O_2 while in Diesel Mode
Selective Catalytic Reduction System	HUG Engineering (or equivalent)	RFV-0890-040-200/300 (or equivalent)	Catalyst: Vanadium Pentoxide Reactor Temperature: 608 ˚F to 908 ˚F Outlet Temperature: 608 ˚F to 908 ˚F Max Flow: 143,000 acfm Control Efficiency: 6ppmvd NOx @15%O_2 while in NG Mode; 35ppmvd NOx @15%O_2 while in Diesel Mode

73. The Permittee shall not modify the equipment subject to this permit in such a manner so as to exceed the Heat Input Capacities, or deviate from the nominal full-load design specifications as submitted in the AFC, and as identified in Table 1.1, Table 1.2, or Table 1.3. *[NCUAQMD Rule 102 §5.0]*

Table 1.1 S-1 Through S-10 Engine Specifications

Primary Fuel	Natural Gas
Backup Fuel	CARB Diesel
Design Ambient Temperature	67.5 ˚F
Nominal Heat Input Rate (HHV)	143.9 MMBtu/hr natural gas plus 0.79 MMBtu pilot fuel (natural gas mode) – OR – 148.9 MMBtu/hr CARB Diesel Fuel (diesel mode)
Nominal Exhaust Temperature	728˚F
Exhaust Flow Rate	121,500 acfm
Exhaust Release Height	100 Feet (above grade)
Exhaust O2 Concentration, dry volume	11.6%
Exhaust CO2 Concentration, dry volume	5.3%
Emission Controls	Lean Burn Technology and SCR; Oxidation Catalyst
SIC	4911

SCC	20100202 natural gas mode; 20100301 diesel mode

Table 1.2 S-11 Engine Specifications

Primary Fuel	CARB Diesel
Nominal Heat Input Rate (HHV)	4.0 MMBtu/hr
Heat Input, gal/hr	29.1
SIC	4911
SCC	20100301

Table 1.3 S-12 Engine Specifications

Primary Fuel	CARB Diesel
Nominal Heat Input Rate (HHV)	1.68 MMBtu/hr
Heat Input, gal/hr	12.3
SIC	4911
SCC	20201607

74. The Permittee shall only fire reciprocating engines S-1 through S-10 with fuel which meets or exceeds the fuel specifications identified in Tables 1.3 and 1.4. Prior to firing reciprocating engines S-1 through S-10 with an Alternative Fuel or CARB Diesel with additives, the Permittee shall make a request to the APCO to switch fuel types. The request shall include all necessary information to characterize emission changes which may occur as a result of the change. The Permittee shall not fire reciprocating engines S-1 through S-10 with a liquid fuel other than CARB Diesel without prior approval from the APCO. [*NCUAQMD Rule 102 §5.0*]

Table 1.4 Fuel Specifications for S-1 through S-10

Fuel Type	Property	Value
Natural Gas	Sulfur Content	< 1 gr / 100scf per test; annual average <0.33gr/100scf
CARB Diesel	Sulfur Content	< 15 ppm

75. Reciprocating engines S-1 through S-10 shall be equipped with a monitoring system capable of measuring and recording hours of operation (in tenths of an hour) and fuel consumption (in cubic feet and gallons) while operating in natural gas mode and diesel mode. The measuring devices shall be accurate to plus or minus 1% at full scale, and shall be tested at least once every twelve months or at more frequent intervals if necessary to ensure compliance with the 1% accuracy requirement. [*NCUAQMD Rule 102 §5.0*]

76. The exhaust stacks shall not be fitted with rain caps or any other similar device which would impede vertical exhaust flow. [*NCUAQMD Rule 102 §5.0*]

77. The Permittee shall install and maintain a non-resettable hour meter with a minimum display capability of 9,999 hours upon the Emergency IC Diesel Generators S-11 and S-12. [*NCUAQMD Rule 102 §5.0*]

78. The Emergency IC Diesel Generators S-11 and S-12 shall use one of the following fuels:
    a. CARB Diesel Fuel, or
    b. An alternative diesel fuel that meets the requirements of the Verification Procedure (as codified in CCR Title 13 Sections 2700-2710), or
    c. CARB Diesel Fuel used with fuel additives that meets the requirements of the Verification Procedure (as codified in CCR Title 13 Sections 2700-2710), or
    d. Any combination of a) through d) above.

79. The reciprocating engines S-11 and S-12 shall be certified to meet the EPA Tier 3 emission levels. [*40 CFR 60 Subpart IIII*]

80. The Permittee shall obtain APCO approval for the use of any equivalent engine for S-11 or S-12 not specifically approved by this Authority to Construct. Approval of an equivalent engine shall be made only after the APCO's determination that the submitted design and performance data for the proposed IC engine is equivalent to the approved engine. [*NCUAQMD Rule 102 §5.0*]

81. The Permittee's request for approval of an equivalent engine shall include the following information: engine manufacturer and model number, horsepower (hp) rating, exhaust stack information, and manufacturer's guaranteed emission concentrations. [*NCUAQMD Rule 504 §4.0; NCUAQMD Rule102 §5.0*]

82. The Permittee's request for approval of an equivalent engine shall be submitted to the NCUAQMD at least 90 days prior to the planned installation date. The Permittee shall also notify the NCUAQMD at least 30 days prior to the actual installation of the NCUAQMD approved equivalent engine. [*NCUAQMD Rule 103 §6.0*]

83. The Permittee shall install exhaust gas temperature monitoring devices at the inlet and the outlet of the oxidation catalyst. [*40 CFR §63.6625; BACT*]

84. Ammonia injection points shall be equipped with operational ammonia flow meters and injection pressure indicators. The flow meters shall be accurate to plus or minus 1% at full scale and shall be calibrated at least once every twelve months or at more frequent intervals if necessary to ensure compliance with the 1% requirement. [*NCUAQMD Rule 102 §5.0*]

85. The Permittee shall install points of access to the Emission Devices, Control Devices, and Continuous Emission Monitoring Devices such that source testing in accordance with the appropriate reference test methods can be performed. All points of access shall conform to the latest Cal-OSHA safety standards. For purposes of compliance with this part, appropriate test methods shall mean the test methods identified in the Testing and Compliance Monitoring Conditions section of this Permit; and the collection of gas samples with a portable NOx, CO, and O_2 analyzer. Sample collection ports shall be located in accordance with 40 CFR Part 60 Appendix A, and with the CARB document entitled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [*NCUAQMD Rule 102 §5.0*]

86. Each reciprocating engine shall be equipped with a continuous emission monitor (CEM) for NOx, CO, and O_2. Continuous emissions monitor(s) shall meet the requirements of 40 CFR part 60, Appendices B and F, and NCUAQMD-approved protocol during normal operations. The monitors shall be designed and operated so as to be capable of monitoring emissions during normal operating conditions and during Startup and Shutdowns Periods. [*NCUAQMD Regulations Appendix B*]

87. The Permittee shall demonstrate compliance with the ammonia slip limit by using the following calculation procedure: The ammonia emission concentration shall be verified by the continuous recording of the ratio of the ammonia injection rate to the NOx inlet rate into the SCR control system (molar ratio). The maximum allowable NH3:NOx molar ratio shall be determined during any required source test, and shall not be exceeded until reestablished through another valid source test. Alternatively, the Permittee may be required to install, operate and maintain a continuous in-stack emissions monitor for emissions of ammonia. The Permittee shall obtain APCO approval for the installation and use the ammonia CEMs equipment at least 60 days prior to the planned installation date. [*NCUAQMD Rule 103 §6.0*]

88. Both onsite and offset emission credits were utilized for this project. Prior to commencement of construction, in accordance with Rule 106 §6.6, the Permittee shall provide to the NCUAQMD APCO documentation of transfer of ownership of offsite Emission Reduction Credits sufficient to offset the emissions identified in Table 3. Prior to commencement of the Commissioning Period, the Permittee shall surrender to the NCUAQMD sufficient offsite emission credits to offset the increases listed in Table 3.0 below. NOx credits provided to offset PM_{10} increases shall be at an inter-pollutant ratio of 3.58:1 after the appropriate distance ratio is applied. The Permittee shall permanently shut down the existing facility and all emission units permitted under Title V Permit To Operate NCU 059-12 in accordance with Condition #110. [*40 CFR 51, Appendix S; NCUAQMD Rule 110*]

Table 3.0 HBRP Required Offsite Offsets By Quarter

Pollutant	Pollutant Quantities in Tons			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
PM_{10}	2.45	2.35	2.37	2.34
ROC	0.62	0.59	0.59	0.59

EMISSION LIMITING CONDTIONS

89. The Permittee shall not discharge particulate matter into the atmosphere from any combustion source in excess of 0.20 grains per cubic foot of dry gas calculated to 12 percent CO_2 at standard conditions. [*NCUAQMD Rule 104 §3.1*]

90. The Permittee shall not discharge sulfur dioxide into the atmosphere in excess of 1000 ppmv or 40 tons per year. [*NCUAQMD Rule 104 §5.0*]

91. Visible emissions from reciprocating engines S-1 through S-12 shall not be as dark or darker in shade as that designated as No. 1 on the Ringleman Chart, or of such opacity so as to obscure an observer's view to a degree equal to or greater than 20%, for any period or periods aggregating more than 3 minutes in any one hour. This visible emission limitation shall not apply during Startup or Shutdown Periods. *[NCUAQMD Rule 102 §5.0]*

92. The Permittee The Permittee shall not operate reciprocating engines S-1 through S-10 such that the emissions of NOx, from a combination of all engines, exceeds 392 lbs per hour. Furthermore, except as provided below, the Permittee shall not operate reciprocating engines S-1 through S-10 such that more than 2 units are in a Diesel Startup Period during any one Clock Hour. Following completion of the emissions testing for all ten units required under Condition #163, the Permittee may request the use of an alternative compliance demonstration method. Such a request shall include, but not be limited to the following:

    A. Identification of alternative operational limit(s) and/or alternative method(s) for determining compliance with the facility wide pound per hour NOx emission limit; and

    B. Source test data and calculations demonstrating that revisions to emission factors, and/or utilization of an alternative compliance determination method, are appropriate.

    Upon written approval by the District of the alternative compliance demonstration method, the permit limitation on the number of Diesel Mode Startups may be modified. In no event shall the facility wide hourly limit of 392 lbs of NOx be increased, nor any operational activities permitted, which would allow an exceedance of any emission limitation. *[NCUAQMD Rule 102 §5.0]*

93. The Permittee shall not discharge diesel particulate matter from reciprocating engines S-1 through S-10 while operating in Diesel Mode such that emissions of Diesel Particulate Matter exceed 0.11 g/bhp-hr. *[NSPS 40 CFR Part 60 Subpart IIII]*

94. The Permittee shall not discharge Carbon Monoxide from reciprocating engines S-1 through S-10 in excess of 0.14 g/bhp-hr or 20 ppmvd @ 15% O_2. *[40 CFR 63 Subpart ZZZZ]*

HEAT INPUT & FUEL LIMITATIONS

Engines S-1 Through S-10

95. The Permittee shall not operate reciprocating internal combustion engines S-1 through S-10 in such a manner so as to exceed the heat input capacities listed in Table 4.0 on a per engine basis. *[NCUAQMD Rule 102 §5.0]*

Table 4.0 Heat Input Limitations Per Engine

Each Unit[1]		Heat Input, MMBtu (HHV)	
		Hourly 3 hr rolling average	Daily 24 hour rolling average
Natural Gas Mode[2]	Natural Gas	143.9	3,454
	Diesel (Pilot)	0.8	19
Diesel Mode	Diesel	148.9	3574

Notes:

1) Each unit can only run in either Natural Gas or Diesel Mode, not both simultaneously.
2) Heat Input in Natural Gas Mode is the sum of natural gas and diesel pilot also.

96. The Permittee shall not operate reciprocating internal combustion engines S-1 through S-10 in such a manner so as to exceed the heat input capacities listed in Table 4.1 below calculated as a sum of all 10 engines. *[NCUAQMD Rule 102 §5.0]*

Table 4.1 Heat Input Limitations S-1 Through S-10 Engines Combined

Sum of All 10 Units		Heat Input, MMBtu (HHV)		
		Hourly	Daily	Annual
Natural Gas Mode[1]	Natural Gas	1,439	34,536	9,277,233[2]
	Diesel Pilot	7.9	190	51,576
Diesel Mode	Diesel	1,489	30,376[2,3]	148,900[2]

Notes:

1) Total Heat Input in Natural Gas Mode is the sum of natural gas and diesel pilot.
2) This limit applies to operation for maintenance and testing, and during periods of Natural Gas Curtailments as defined in this permit. The limit shall not apply to fuel consumed during the Commissioning Period.
3) This limit was established to ensure compliance with the $PM_{2.5}$ standard

97. The Permittee shall not exceed the diesel fuel firing limits listed in Table 4.2 below while operating reciprocating engines S-1 through S-10 in Natural Gas Mode. *[NCUAQMD Rule 102 §5.0]*

Table 4.2 Diesel Fuel Firing Limitations (Pilot)

Engines S-1 Through S-10	Gallons of Diesel Fuel		
	Hourly 3 hr rolling average	Daily 24 hour rolling average	Annual 365 day rolling average
All Combined	58	1,402	376,734

98. The Permittee shall not exceed the diesel fuel firing limits listed in Table 4.3 below while operating reciprocating engines S-1 through S-10 in Diesel Mode. *[NCUAQMD Rule 102 §5.0]*

Table 4.3 Diesel Fuel Firing Limitations

Engines S-1 Through S-10	Gallons of Diesel Fuel		
	Hourly 3 hr rolling average	Daily 24 hour rolling average	Annual 365 day rolling average
Per Engine	1,088	26,106	-
All Combined	10,876	221,877[1,2]	1,087,630[1]

Notes:

1) This limit applies to operation for maintenance and testing, and during periods of Natural Gas Curtailments as defined in this permit. The limit shall not apply to fuel consumed during the Commissioning Period.

2) This limit was established to ensure compliance with the $PM_{2.5}$ standard (85% average load)

POLLUTANT LIMITATIONS

S-1 - S-10 Startup & Shutdown Periods

99. The Permittee shall not operate reciprocating engines S-1 through S-10, such that they individually discharge pollutants exceeding the limits identified in Table 5.0 below during Startup or Shutdown Periods. *[NCUAQMD Rule 102 §5.0]*

Table 5.0 Start & Shutdown Period Emission Limits

Mode of Operation	Pollutant				
	NOx	CO	ROC	PM10	SOx
Natural Gas, lb/hr	23.6	24.1	17.9	3.6	0.4
Diesel Mode, lb/hr	164	25.5	17.2	10.8	0.22

S-1 - S-10 Natural Gas Mode

100. The Permittee shall not operate reciprocating engines S-1 through S-10, such that they individually discharge pollutants exceeding the limits identified in Table 5.1 below based upon a three (3) hour average with the exception of NOx which shall be based upon a one (1) hour average. The limits shall not apply during Startup or Shutdown Periods. *[40 CFR 63.6(f)(1), NCUAQMD Rule 102 §5.0]*

Table 5.1 Natural Gas Mode Emission Limits – per engine

Pollutant	Emission Rate		
	ppmvd @ 15% O_2	lb/hr	lb/MMBtu
CO	13	4.13	0.029
NH_3	10	1.9	0.013
NOx	6.0	3.1	0.022
PM_{10}	-	3.6	-
ROC	28	5.1	0.035
SOx	-	0.40	0.0028

101. The combined discharge of pollutants, from the reciprocating engines S-1 through S-10 shall not exceed the limits listed in Table 5.2 below during any Calendar Day in which none of the engines are operated in Diesel Mode for any period of time. For purposes of compliance with this condition, the emissions from Startup and Shutdown Periods shall be included in the daily calculation of emissions. *[NCUAQMD Rule 102 §5.0]*

Table 5.2 S-1 Through S-10 Combined Natural Gas Mode Limit

Pollutant	Emission Rate lb/Day
CO	1,589
NH_3	456
NOx	1,360
PM_{10}	864
ROC	1,608
SOx	97

S-1 - S-10 Diesel Mode

102. The Permittee shall not discharge pollutants into the atmosphere from the reciprocating engines S-1 through S-10 while in Diesel Mode, based upon a three (3) hour rolling average, in excess of the emission limits identified in Table 5.3 below. The limits shall not apply during Startup or Shutdown Periods. *[40 CFR 63.6(f)(1), NCUAQMD Rule 102 §5.0]*

Table 5.3 Diesel Mode Emission Limits – per engine

Pollutant	Emission Rate		
	ppmvd @ 15% O_2	lb/hr	lb/MMBtu
CO	20.0	6.9	0.047
NH_3	10	2.1	0.014
NOx	35.0	19.9	0.134
PM_{10}	-	10.8	0.137
ROC	40.0	7.9	0.053
SOx	0.40	0.22	0.0016

103. The discharge of Diesel Particulate Matter into the atmosphere from the reciprocating engines S-1 through S-10 while in Diesel Mode shall not exceed the

emission limits identified in Table 5.4 below. The limits shall not apply during the Commissioning Period as defined in this permit. *[NCUAQMD Rule 102 §5.0;]*

Table 5.4 Diesel Particulate Matter Limitations

Engines S-1 Through S-10	Diesel Particulate Matter (pounds)		
	Hourly 3 hr rolling average	Daily 24 hour rolling average	Annual 365 day rolling average
Per Engine	5.56	133.4	-
All Combined	55.6	1,334	5,560

104. The combined discharge of pollutants from the reciprocating engines S-1 through S-10 during any Calendar Day shall not exceed the limits listed in Table 5.5 below during any Calendar Day in which one or more of the engines are operated in diesel mode for any period of time. For purposes of compliance with this condition, the emissions from Startup and Shutdown Periods shall be included in the daily calculation of emissions.

Table 5.5 S-1 Through S-10 Combined Diesel Mode Limit

Pollutant	Emission Rate lb/Day
CO	2,219
NH_3	506
NOx	9,103
PM_{10}	1,542
ROC	2,183
SOx	97

For purposes of determining compliance with the daily PM_{10} limit in Table 5.5, the Permittee shall not operate reciprocating engines S-1 through S-10 in Diesel Mode for more than 142 engine-hours per day. Following completion of the PM_{10} emissions testing required under Condition #163 on all 10 engines, the Permittee may request the use of an alternative compliance demonstration method. Such a request shall include, but not be limited to the following:

C. Identification of the highest PM emission rates of the 10 units as determined during initial performance testing.

D. Identification of alternative operational limit(s) and/or alternative method(s) for determining compliance with the facility wide pound per day PM emission limit; and

E. Source test data and calculations demonstrating that revisions to emission factors and/or compliance determination method(s) are appropriate.

Upon written approval by the District of the alternative compliance demonstration method, the permit limitation on the number of hours of operation in Diesel Mode may

be modified. The highest PM pollutant values identified during the initial performance testing shall become the permitted emission limits for all engine units. In no event, shall the newly established emission limits be in excess of 10.8 lbs/hr. (the manufacturer's guaranteed emission rates indentified in the AFC), and in the ATC materials submitted by the applicant. In no event shall the facility wide daily limit of 1,542 pounds be increased, nor any operational activity permitted, which would allow an exceedance of any emission limitation. Compliance with the daily facility wide PM emission limit shall be calculated as a function of engine hourly emission rate times the number of hours of operation per day. *[NCUAQMD Rule 102 §5.0]*

105. The combined discharge of pollutants from the reciprocating engines S-1 through S-10 during any calendar year shall not exceed the limits listed in Table 5.6 below. *[NCUAQMD Rule 102 §5.0]*

Table 5.6 S-1 Through S-10 Combined Annual Emission Limits

Pollutant	Emission Rate Tons/Yr
CO	172.7
NH_3	63.3
NOx	179.1
PM_{10}	119.8
ROC	190.8
SOx	4.3

Engines S-11 and S-12

106. The Permittee shall not operate reciprocating engines S-11 and S-12 such that pollutant discharge into the atmosphere exceeds the quantities in Table 5.7 below. *[NCUAQMD Rule 102 §5.0]*

Table 5.7 Reciprocating Engines S-11 and S-12 Emission Limits

Unit	Pollutant	g/Hp – hr	lb/hr
S-11 Emergency Generator	CO	0.63	0.65
	DPM	0.05	0.05
	NOx	3.47	3.59
	ROC (non-methane HC)	0.4	0.41
	SOx	-	.0061
S-12 Fire Pump	CO	0.59	.27
	DPM	0.14	0.06
	NOx	4.9	2.27
	ROC (non-methane HC)	0.5	0.23
	SOx	-	0.0026

107. The combined discharge of pollutants from the reciprocating engines S-11 through S-12 during any calendar year shall not exceed the limits listed in Table 5.8 below. *[NCUAQMD Rule 102 §5.0]*

Table 5.8 S-11 and S-12 Combined Annual Emission Limits

Pollutant	Emission Rate lbs/Yr
CO	45
NOx	287
DPM	5.5
ROC	31.5
SOx	0.4

STARTUP COMMISSIONING & SIMULTANEOUS OPERATION

108. This Permit supplements existing NCUAQMD Permit Numbers for the HBPP of NS-020 (Boiler #1), NS-21 (Boiler #2) and NS-057 (Turbines) until such time as the sources are decommissioned. [*NCUAQMD Rule 102 §5.0]*

109. The Permittee shall notify the NCUAQMD of the anticipated date of initial startup of the reciprocating engines S-1 through S-10 not more than 60 days, or less than 30 days prior to initial startup. The Permittee shall notify the APCO of the actual startup of reciprocating engines S-1 through S-10 not more than 15 days after actual initial startup. *[NCUAQMD Rule 102 §5.0]*

110. The existing generating units at Humboldt Bay Power Plant shall be shut down as soon as possible following the commercial operation of all of the reciprocating engines S-1 through S-10. The existing generating units at Humboldt Bay Power Plant [NCUAQMD Permit Units NS-020 (Boiler #1), NS-21 (Boiler #2) and NS-57 (Turbines)] and any of the new HBRP reciprocating engines S-1 through S-10 shall not be in simultaneous operation for more than 180 calendar days, including their individual Commissioning Periods; and shall be shutdown and their Permits to Operate (PTOs) surrendered once engines S-1 through S-10 have successfully completed their Commissioning Phase as defined elsewhere in this permit. Operation of the existing plant units and any engine or engines for any portion of a calendar day, shall accrue toward the maximum limit of 180 days. *[NCUAQMD Rule 110, Rule 102 §5.0]*

111. Selective catalytic reduction (SCR) systems and oxidation catalysts shall serve each reciprocating engine except as provided for in Condition #114. Permittee shall submit SCR and oxidation catalyst design details to the NCUAQMD for review and approval at least 90 days prior to scheduled delivery of these systems to the site. The Permittee shall not install or operate the SCR and oxidation catalyst systems without authorization from the APCO. *[NCUAQMD Rule 110, Rule 102 §5.0]*

112. Permittee shall submit continuous emission monitor design, installation, and operational details to the NCUAQMD within 120 days following commencement of construction. *[NCUAQMD Rule 102 §5.0]*

113. In accordance with the NCUAQMD approved Commissioning Plan required under Condition #123, the reciprocating engines shall be tuned to minimize emissions in the time frame specified in the approved Commissioning Plan. *[NCUAQMD Rule 102 §5.0;]*

114. In accordance with the NCUAQMD approved Commissioning Plan required under Condition #123, the Selective Catalytic Reduction (SCR) system and the oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from each reciprocating engine in the time frame specified in the Commissioning Plan. *[NCUAQMD Rule 102 §5.0;]*

115. The continuous monitors specified in Permit Conditions #75, #83, and #86 shall be installed, calibrated, and operational prior to the first firing of reciprocating engines S-1 through S-10. After first firing, the detection range of the CEMS shall be adjusted as necessary to accurately measure the resulting range of NOx and CO emission concentrations. *[NCUAQMD Rule 102 §5.0;]*

116. The Permittee shall record and monitor the parameters identified in Table 7.0 of this Permit at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation). The Permittee shall use APCO approved methods to calculate heat input rates, oxides of nitrogen mass emission rates (reported as nitrogen dioxide), carbon monoxide mass emission rates, and NOx and CO emission concentrations, summarized for each hour and each day. *[NCUAQMD Rule 102 §5.0; NCUAQMD Regulation Appendix B]*

117. The total number of firing hours of each reciprocating engine S-1 through S-10 without abatement of emissions by the SCR system and the oxidation catalyst shall not exceed 100 hours for each engine during the Commissioning Period. Such operation of each reciprocating engine without abatement shall be limited to discrete Commissioning Activities that can only be properly executed without the SCR system and the oxidation catalyst in place. Upon completion of these activities for each engine, the Permittee shall provide written notice to the NCUAQMD and the unused balance of the allowable firing hours without abatement for that engine shall expire. *[NCUAQMD Rule 102 §5.0]*

118. When one or more reciprocating engines S-1 through S-10 are undergoing Commissioning Activities without an SCR system and oxidation catalyst installed, the Permittee shall not: *[NCUAQMD Rule 102 §5.0]*

    a. Fire more than five uncontrolled reciprocating engines simultaneously.

    b. Operate the uncontrolled engines such that their combined hours of operation exceed 90 engine-hours during any Calendar Day.

c. Operate the uncontrolled engines such that their combined hours of operation while in the "alignment phase" exceed 13 engines-hours during any Calendar Day.

119. During the Commissioning Period while any of the engines are being operated without an SCR system and oxidation catalyst, the Permittee shall not operate reciprocating engines S-1 through S-10, such that the combined emissions from all of the engines regardless of their commissioning status, exceed any of the limits in Table 5.9 below: *[NCUAQMD Rule 102 §5.0]*

Table 5.9 S-1 through S-10 Combined Commissioning Emission Limits

Pollutant	lbs/hr	lbs/day
CO	197.2	2,662
NOx	323.3	4,365
PM_{10}	54	1,296
ROC (as Methane)	86.6	1,559
SOx (SO_2)	2.0	48.4

120. For each engine during its Commissioning Period, after four hours of steady-state operation of the SCR system and the oxidation catalyst has occurred, the NOx and CO emissions from that reciprocating engine shall thereafter comply with the limits specified in Permit Conditions #99 through #105. For purposes of compliance with this condition, steady-state operation shall mean: the engine, SCR system, and oxidation catalyst all functioning according to manufacturers specifications and operating in compliance with emission limits as determined by the CEMS. In no event, shall the Commissioning Period for each engine exceed 180 consecutive calendar days beginning on the first day the engine is first fired. *[NCUAQMD Rule 102 §5.0]*

121. Firing hours on 100% CARB Diesel Fuel or Alternative Liquid Fuel during the Commissioning Period shall not be considered Maintenance and Testing for purposes of compliance with the annual operating hour limitations specified in the Operational Conditions section of this Permit. *[NCUAQMD Rule 102 §5.0]*

122. The total mass emissions of NOx, CO, ROC, PM_{10}, and SOx that are emitted from the reciprocating engines during the Commissioning Period shall accrue towards the annual emission limits specified in Condition #107. *[NCUAQMD Rule 102 §5.0]*

123. The Permittee shall submit a plan to the NCUAQMD at least four weeks prior to the first operation of the first of reciprocating engines S-1 through S-10, describing the procedures to be followed during the Commissioning Period. The plan shall include a description of each Commissioning Activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the reciprocating engines, the installation and operation of the SCR systems and the oxidation catalysts, the installation, calibration, and testing of the NOx and CO continuous emissions

monitors, and any activities requiring the firing of each unit without abatement by an SCR system or oxidation catalyst. *[40 CFR Part 63; NCUAQMD Rule 102 §5.0]*

124. Not later than 90 days prior to first operation, the Permittee shall prepare and submit to the NCUAQMD for approval a plan for complying with the requirements of 40 CFR 63 Subpart ZZZZ. This compliance plan shall provide for an initial performance test on each engine to demonstrate that each oxidation catalyst is achieving a minimum 70% reduction in CO over a four hour period. During the initial performance test, the Continuous Emission Monitors shall successfully complete a performance evaluation in accordance using PS3 and 4A of 40 CFR Part 60 Appendix B; the oxidation catalyst pressure drop and inlet temperature shall be measured using ASTM D6522-00 [§63.6625(a)]; and the CEMS data collected in accordance with §63.6625(a) with the data reduced to 1-hour averages.

125. Not later than 90 days prior to first operation, the Permittee shall prepare and submit to the NCUAQMD for approval a plan for complying with the requirements of 40 CFR 60 Subpart IIII. This compliance plan shall provide for an initial performance test on each reciprocating engine to demonstrate compliance with the NOx and PM limitations of 40 CFR §60.4204(c)(1) and (c)(2) and shall establish operating parameters to be monitored continuously to ensure that each reciprocating engine continues to meet the applicable emission standards.

OPERATIONAL CONDITIONS

Engines S-1 through S-10

126. In the event of an excess emission incident, regardless of the cause, the Permittee shall immediately take corrective action to minimize the release of excess emissions. Notice shall be provided to the NCUAQMD as indicated in the Reporting and Recordkeeping Section of this Permit. For purposes of compliance with this condition, excess emissions shall mean discharge of pollutants in quantities which exceed those authorized by Federal, State, NCUAQMD Rules, and this Permit. *[40 CFR 70.6(a)(3)(iii)(B); NCUAQMD Rule 105 §5.0]*

127. All equipment listed in Table 1.0 Authorized Emission Devices and 2.0 Authorized Control Devices shall be operated and maintained by the Permittee in accordance with manufacturer's specifications for optimum performance; and in a manner so as to minimize emissions of air contaminants into the atmosphere. *[NCUAQMD Rule 102 §5.0]*

128. The Permittee shall implement and maintain a written Startup, Shutdown, and Malfunction Plan as described in as described in 40 CFR 63.6(e) (3) which contains specific procedures for maintaining the reciprocating engines S-1 through S-12, their associated control devices, their associated CEMS, sensors, measuring devices, and their associated exhaust gas duct work, during periods of startup, shutdown, and malfunction. The plan must clearly describe the startup and shutdown sequence procedure for each unit. The Plan shall also include a specific program of corrective actions to be implemented in the event of a malfunction in

either the process or control systems. Modifications to the Plan are subject to APCO approval and the Permittee shall not operate the reciprocating engines S-1 through S-12 and their associated control devices unless a NCUAQMD approved Startup, Shutdown, and Malfunction Plan is in effect. The Plan shall be submitted to the NCUAQMD not less than thirty (30) calendar days prior to the Commissioning Period for any of reciprocating engines S-1 through S-10. *[NCUAQMD Rule 102 §5.0]*

129. The Permittee shall develop, implement and maintain a written Device Operational Plan that contains specific procedures for operating the reciprocating engines S-1 through S-12, their associated control devices, their associated CEMS, sensors, measuring devices, and their associated exhaust gas duct work under the varying load conditions which may occur during normal modes of operation. The Plan shall also include specific protocols to be followed when transitioning between modes of operation. This plan shall be consistent with the requirements of this Permit, and all local, state and federal laws, rules, and regulations. The plan shall include, but not be limited to, daily system integrity inspections and the recording of operational parameters. The Plan shall be submitted to the NCUAQMD not more than sixty (30) calendar days following expiration of the Commissioning Period for any of reciprocating engines S-1 through S-10. The Plan is subject to APCO approval. The Permittee shall not operate the reciprocating engines S-1 through S-12 and their associated control devices, after the expiration of the Commissioning Period for any of the reciprocating engines plus 60 days, unless a NCUAQMD approved Device Operational Plan is in effect. *[NCUAQMD Rule 102 §5.0]*

130. The Permittee shall develop, implement and maintain a written Device Maintenance & Replacement Plan that contains specific procedures for equipment maintenance and identifies replacement intervals for components of the reciprocating engines S-1 through S-12, their associated control devices, their associated CEMS, sensors, measuring devices, and their associated exhaust gas duct work. The Plan shall be submitted to the NCUAQMD not more than thirty (30) calendar days following expiration of the Commissioning Period for any of reciprocating engines S-1 through S-10. The Plan is subject to APCO approval. The Permittee shall not operate the reciprocating engines S-1 through S-12 and their associated control devices, after the expiration of the Commissioning Period for any of the reciprocating engines plus 60 days, unless a NCUAQMD approved Device Maintenance & Replacement Plan is in effect. *[NCUAQMD Rule 102 §5.0]*

131. The Permittee shall only operate the Reciprocating engines S-1 through S-10 in Natural Gas Mode except during the Commissioning Period, during Maintenance and Testing, and during Natural Gas Curtailments as set forth in this permit. *[NCUAQMD Rule 102 §5.0]*

132. The Permittee shall not operate reciprocating engines S-1 through S-10 such that Startup Periods exceed 60 minutes in length. *[NCUAQMD Rule 102 §5.0]*

133. The Permittee shall not operate reciprocating engines S-1 through S-10 such that Shutdown Periods exceed 30 minutes in length. *[NCUAQMD Rule 102 §5.0]*

134. The Permittee shall not operate the reciprocating engines S-1 through S-10 such that the combined hours of operation during Startup and Shutdown Periods exceeds 30 engine-hours per day. *[NCUAQMD Rule 102 §5.0]*

135. The Permittee shall not operate the reciprocating engines S-1 through S-10 such that the combined hours of operation during Startup and Shutdown Periods exceeds 3,650 engine-hours per calendar year. Of the 3,650 engine hours available hours, the hours of operation during Startup and Shutdown Periods in Diesel Mode shall not exceed 500 engine-hours per calendar year. *[NCUAQMD Rule 102 §5.0]*

136. The Permittee shall not operate any of the reciprocating engines S-1 through S-10 below 50% load except during Startup and Shutdown Periods. *[NCUAQMD Rule 102 §5.0]*

137. The Permittee shall not operate the reciprocating engines S-1 through S-10 for more than 80 engine-hours per Calendar Day at loads less than 12.0 MW. *[NCUAQMD Rule 102 §5.0]*

138. While operating the reciprocating engines S-1 through S-10 in Diesel Mode, the Permittee shall fire the engines:

    a. Only with CARB Diesel as specified in Table 1.4 Fuel Specifications for S-1 through S-10;

    b. For more than 50 hours per year for maintenance and testing per engine; and

    c. Such that the combined engine operating hours do not exceed 1000.0 engine hours per year on a 365 day rolling average basis.

139. For each Oxidation Catalyst installed, during the performance testing required pursuant to the Testing and Monitoring section of this Permit, the Permittee shall determine the pressure drop across each catalyst. The Permittee shall operate the reciprocating engines S-1 through S-10 such that the pressure drop across the catalyst does not exceed the following acceptable range for any period of time: The acceptable pressure range is two inches of water column (plus or minus 10%) deviation from the pressure drop established during performance testing. *[40 CFR 63 Subpart ZZZZ]*

140. The Permittee shall not operate reciprocating engines S-1 through S-10 if the inlet temperature of the oxidation catalyst is outside of the acceptable operating range for any period of time. The acceptable operating range of the oxidation catalyst is greater than or equal to 450 ˚F and less than or equal to 1350 ˚F. Each reciprocating engine is paired with a single oxidation catalyst unit. For purposes of compliance with this condition, each engine and catalyst pair is evaluated separately. This Condition does not apply during Startup or Shutdown Periods or during malfunctions. *[40 CFR 63 Subpart ZZZZ]*

141. The Permittee shall not operate reciprocating engines S-1 through S-10 unless the CO emissions from the units are abated by the oxidation catalyst at a rate greater than or equal to 70% over uncontrolled emission levels, calculated on a 3 hour rolling average. Verification of the emissions reduction shall be completed in accordance with 40 CFR 63 Subpart ZZZZ. This Condition does not apply during Startup or Shutdown Periods or during malfunctions. [*40 CFR 63 Subpart ZZZZ]*

Engines S-11 and S-12

142. The Permittee shall not operate the reciprocating engines S-11 and S-12, for the purpose of maintenance and testing, in excess of the hour limits listed in Table 6.1 below *[NCUAQMD Rule 102 §5.0*]:

Table 6.1 S-11 and S-12 Hourly Operating Limits

Device	Daily	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
S-11	1	12	12	13	13
S-12	1	12	12	13	13

143. The Permittee shall not operate the reciprocating engines S-11 and S-12, for the purpose of maintenance and testing, within the same 24 hour period. [NCUAQMD Rule 102 §5.0]

144. The Permittee shall not operate the reciprocating engines S-11 and S-12, for the purpose of maintenance and testing, when any of the reciprocating engines S-1 through S-10 are operating in diesel mode. [*NCUAQMD Rule 102 §5.0]*

145. The Permittee shall not operate reciprocating engine S-11, for the purpose of maintenance and testing, for more than 45 minutes in any 60 minute period. *[NCUAQMD Rule 102 §5.0]*

REPORTING & RECORDKEEPING

146. The Permittee shall report all occurrences of breakdowns of the equipment listed in Table 1.0 Authorized Emission Devices or Table 2.0 Authorized Control Devices which result in the release of emissions in excess of the limits identified in this Permit. Said report shall be submitted to the NCUAQMD in accordance with the timing requirements of NCUAQMD Rule 105 §5.0.

147. The Permittee shall maintain a Breakdown log that describes the breakdown or malfunction, includes the date and time of the malfunction, the cause of the malfunction, corrective actions taken to minimize emissions and the date and time when the malfunction was corrected. *[NCUAQMD Rule 102 §5.0]*

148. The Permittee shall immediately record the following information when an event occurs where emissions from the equipment listed in Table 1.0 Authorized Emission Devices are in excess of any limits incorporated within this permit:
    a. Date and time of the excess emission event
    b. Duration of the excess emission event
    c. Description of the condition or circumstance causing or contributing to the excess emission event
    d. Emission unit or control device or monitor affected
    e. Estimation of the quantity and type of pollutants released
    f. Description of corrective action taken
    g. Actions taken to prevent reoccurrence of excess emission event.

149. The Permittee shall provide to the NCUAQMD, a completed "Compliance Certification" form signed by the Facility's Responsible Official which certifies the compliance status of the facility twice per calendar year. The compliance certification form must be submitted to the NCUAQMD according to the following schedule: The semiannual certification (covering quarters 1 and 2) must be submitted prior to July 31st of the reporting year; and the annual certification (covering quarters 1, 2, 3, and 4) prior to March 1st of the following calendar year. The content of the Certification shall include copies of the records designated in Table 7.0 to be kept "Annually".

150. The Permittee shall maintain a monthly log of usage for the Emergency IC Diesel Generators S-11 and S-12 in accordance with applicable Reporting Requirements for Emergency Standby Engines, Item (e)(4)(I) of Section 93115, Title 17, California Code of Regulations, Air Toxic Control Measure (ATCM) for Stationary Compression Ignition (CI) engines. The monthly log of usage shall list and document the nature of use for each of the following by recording the hour meter readings for each operational event:
    a. Emergency use hours of operation;
    b. Maintenance and testing hours of operation (e.g., load testing, weekly testing, rolling blackout, general power outage, etc
    c. Hours of operation for emission testing to show compliance with §93115(e)(2)(A)3 and (e)(2)(B)3 of the ATCM;
    d. Hours of operation to comply with requirements of NFPA 25;
    e. Hours of operation for all other uses other than those specified in section (e)(2)(A)3 and (e)(2)(B)3 of the ATCM;
    f. Fuel used through the retention of fuel purchase records that account for all fuel used in the engine and all fuel purchased for use in the engine, and, at a minimum, contain the following information for each individual fuel purchase transaction:
        i. Identification of the fuel purchased as either CARB Diesel, or an alternative diesel fuel that meets the requirements of the Verification Procedure;
        ii. Sulfur content of the fuel;
        iii. Amount of fuel purchased;
        iv. Date when the fuel was purchased;

v. Signature of owner or operator or representative of Permittee who received the fuel; and
vi. Signature of fuel provider indicating fuel was delivered.

151. The Permittee shall continuously maintain onsite for the most recent five year period and shall be made available to the NCUAQMD APCO upon request, the records as listed in Table 7.0 below.

Table 7.0 Required Records for Engines S-1 through S-10

Frequency	Information to be Recorded
Upon Occurrence	A. Records of maintenance conducted on engines (40 CFR 60 Subpart IIII) B. Time, duration, and fuel firing mode for each engine startup C. Time, duration, and fuel firing mode for each engine shutdown D. Time, duration and reason for each period of operation in Diesel Mode E. For each bulk delivery of diesel fuel received, certification from the supplier that the diesel fuel meets or exceeds CARB Diesel specifications F. For each bulk delivery of diesel fuel received, the higher heating value (HHV) and sulfur content of the fuel G. Fuel Mode – each operating minute shall be designated as either "Natural Gas" or "Diesel Mode"
At least one electronic reading every 15 minutes	A. NOx (ppmvd @15% O_2) B. CO (ppmvd @15% O_2) C. O_2 (%) D. Exhaust gas temperature as SCR inlet (˚F) E. Exhaust gas temperature at OC inlet (˚F) F. Engine load (%)
Hourly (for each engine)	A. NOx (ppmvd @15% O_2) and lb/hr, on a rolling 3 hour average B. CO (ppmvd @15% O_2) and lb/hr, on a rolling 3 hour average C. ROC (ppmvd @15% O_2) and lb/hr, on a rolling 3 hour average D. NH3 (ppmvd @15% O_2) and lb/hr, on a rolling 3 hour average E. SOx (ppmvd @15% O_2) and lb/hr, on a rolling 3 hour average F. Natural gas fuel consumption (MMBtu HHV, 3-hr rolling average) G. Diesel fuel consumption during Diesel Mode (MMBtu HHV, 3-hr rolling average) H. Volumetric proportion of natural gas to diesel pilot injection when operating in Natural Gas Mode
Daily	A. NOx (lbs/day, total for all engines) B. CO (lbs/day, total for all engines) C. ROC (lbs/day, total for all engines) D. SOx (lbs/day, total for all engines)

Frequency	Information to be Recorded
	E. PM (lbs/day, total for all engines) F. Diesel Particulate Matter (lbs/day, total for all engines) G. Natural gas fuel consumption (MMBtu HHV, for each engine and total for all engines) H. Diesel pilot fuel consumption (MMBtu HHV, all engines combined) I. Diesel fuel consumption during Diesel Mode (MMBtu HHV, for each engine and total for all engines) J. Engine load (% load on a 24 hour average for each engine and total for all engines) K. Hours of operation (each engine and total for all engines as a sum of operating minutes) L. Quantity of fuel combusted (therms and gallons for each engine and total for all engines)
Monthly	A. Sulfur content of natural gas (gr/100scf, monthly fuel testing) B. Natural gas sulfur content (gr/100scf, 12 month rolling average)
Quarterly (combined total for all engines)	A. NOx (tons) B. CO (tons) C. SOx (tons) D. ROC(tons) E. PM (tons) F. Diesel Particulate Matter (tons) G. Natural gas fuel consumption (MMBtu HHV) H. Diesel pilot fuel consumption (MMBtu HHV) I. Diesel fuel consumption during Diesel Mode (MMBtu HHV) J. Sulfur content of natural gas (gr/100scf, 12 month rolling average) K. Hours of operation (for each fuel mode) L. Quantity of fuel combusted (therms, gallons)
Annually (combined total for all engines)	A. NOx (tons) B. CO (tons) C. SOx (tons) D. ROC(tons) E. PM (tons) F. Diesel Particulate Matter (tons) G. Natural gas fuel consumption (MMBtu HHV) H. Diesel pilot fuel consumption (MMBtu HHV) I. Diesel fuel consumption during Diesel Mode (MMBtu HHV) J. Sulfur content of natural gas (gr/100scf, annual average) K. Hours of operation (for each fuel mode) L. Quantity of fuel combusted (therms, gallons)

152. For each Quarter, the Permittee shall submit a written report to the APCO detailing the following items for the operation of the CEMS. The report shall conform to the requirements of NCUAQMD Rules and Regulations Appendix B, Section 2.2, and shall be submitted within 30 days of the end of the quarter.

    a. Time intervals;

    b. Date and magnitude of excess emissions;

    c. Nature and cause of excess (if known);

    d. Corrective actions taken and preventive measures adopted;

    e. Averaging period used for data reporting shall correspond to the averaging period for each respective emission standard;

    f. Applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and

    g. A negative declaration when no excess emissions occurred.

153. The Permittee shall provide notification and record keeping as required pursuant to 40 CFR, Part 60, Subpart A, 60.7.

154. The Permittee shall annually prepare and submit a comprehensive facility wide emission inventory report for all criteria pollutants and toxic air contaminants emitted from the facility. The inventory and report shall be prepared in accordance with the most recent version of the CAPCOA / CARB reference document *Emission Inventory Criteria Guidelines*. The inventory report shall be submitted to the NCUAQMD APCO no later than March 1st of the following calendar year. The inventory report is subject to NCUAQMD APCO approval. *[NCUAQMD Rule 102 §5.0]*

155. The Permittee shall submit the health risk assessment protocol to the NCUAQMD APCO for review no later than 9 months after the Commissioning Period for the reciprocating engines S-1 through S-10 has concluded. *[NCUAQMD Rule 102 §5.0]*

156. No later than 14 months after the Commissioning Period for reciprocating engines S-1 through S-10 has concluded, the Permittee shall submit to the NCUAQMD APCO a revised health risk assessment. The health risk assessment shall be prepared pursuant to an NCUAQMD APCO approved protocol based upon CARB and California Office of Health and Hazard Assessment guidance documents. *[NCUAQMD Rule 102 §5.0]*

157. Not later than 24 hours after determining that diesel mode operation is to occur as a result of an expected Natural Gas Curtailment, the permittee shall notify the APCO by telephone, email, electronic page, or facsimile. The notification shall include, but not be limited to, the following *[NCUAQMD Rule 102 §5.0]*:

    a. The anticipated start time and duration of operation in diesel mode under the Natural Gas Curtailment; and

    b. The anticipated quantity of Diesel fuel expected to be burned under the Natural Gas Curtailment.

158. Not later than 24 hours following the end of a period of any diesel mode operation, the permittee shall notify the APCO by email or facsimile of the following [*NCUAQMD Rule 102 §5.0]* :

    a. The actual start time and end time of the period of diesel mode operation;

    b. The identification of the Reciprocating engines that were operated and the average load at which each reciprocating engine was operated on Diesel fuel during the diesel mode operating period; and

    c. The actual quantity of Diesel fuel consumed during the diesel mode operation.

TESTING & COMPLIANCE MONITORING

159. The Permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F.

160. The Permittee shall monitor and record exhaust gas temperature at the inlet and at the outlet of the oxidation catalyst. *[40 CFR 63 Subpart ZZZZ]*

161. Not less than thirty days prior to the date of any source test required by this Permit, the Permittee shall provide the NCUAQMD APCO with written notice of the planned date of the test and a copy of the source test protocol.

162. Source test results shall be summarized in a written report and submitted to the NCUAQMD APCO directly from the independent source testing firm on the same day, the same time, and in the same manner as submitted to Permittee. Source Test results shall be submitted to the NCUAQMD APCO no later than 60 days after the testing is completed.

163. The Permittee shall demonstrate compliance with all the emission limits identified in this Permit during the Commissioning Period of each of the reciprocating engines S-1 through S-10 using the following methods. Testing shall be conducted both while the engines are operated in Natural Gas Mode and while operated in Diesel Mode. All compliance tests shall be conducted at 50%, 75%, and 95% or greater of the operating capacity of each reciprocating engine. Alternative test methods may be approved by the APCO.

a. Particulate Matter – CARB Method 5 (front and back half) or EPA Methods 201a and 202
b. Diesel Particulate Matter – CARB Method 5 (front half)
c. Visible Emissions
    i. Permittee shall perform a "Visible Emission Evaluation" (VEE) concurrent with particulate matter testing. A CARB certified contractor shall perform such an evaluation.
d. Ammonia – Bay Area Air Quality Management NCUAQMD Method ST-1B
e. Reactive Organic Gases – CARB Method 100
f. Nitrogen Oxides – CARB Method 100
g. Carbon Monoxide – CARB Method 100 & ASTM D6522-00 [NESHAP ZZZZ]
h. Oxygen – CARB Method 100 & ASTM D6522-00 [NESHAP ZZZZ]
    i. Oxygen shall be measured at the inlet and outlet of the oxidation catalyst
    ii. Oxygen measurements shall be made at the same time as the CO measurements
    iii. Pressure drop measurements across the catalyst shall be made at the same time as the CO measurements
i. Natural Gas Fuel Sulfur Content – ASTM D3246
j. Liquid Fuel Sulfur Content – ASTM D5453-93

164. The Permittee shall demonstrate compliance with all the emission limits identified in this Permit for the reciprocating engines S-1 through S-10 once per calendar year unless indicated below, using the following methods. Except as provided in Condition #123, testing shall be conducted while the engines are operated in Natural Gas Mode. All compliance tests shall be conducted at an operating capacity of 50%, 75%, or 95% or greater during the testing of each reciprocating engine. Alternative test methods may be approved by the APCO. *[NCUAQMD Rule 102 §5.0]*

    a. Particulate Matter – CARB Method 5 (front and back half) or EPA Methods 201a and 202
    b. Diesel Particulate Matter – CARB Method 5 (front half)
    c. Visible Emissions - Permittee shall perform a "Visible Emission Evaluation" (VEE) concurrent with particulate matter testing. A CARB certified contractor shall perform such an evaluation.
    d. Ammonia – Bay Area Air Quality Management NCUAQMD Method ST-1B
    e. Reactive Organic Gases – CARB Method 100
    f. Nitrogen Oxides – CARB Method 100
    g. Carbon Monoxide – CARB Method 100
    h. Oxygen – CARB Method 100
        i. Oxygen shall be measured at the inlet and outlet of the oxidation catalyst
        ii. Oxygen measurements shall be made at the same time as the CO measurements

iii. Pressure drop measurements across the catalyst shall be made at the same time as the CO measurements

i. Natural Gas Fuel Sulfur Content – ASTM D3246
j. Liquid Fuel Sulfur Content – ASTM D5453-93

165. The engines shall be tested on a rotating basis with all of the engines to be tested in natural gas mode each year and all engines tested at the three different load values at least once every three years; and that each engine is tested at a different load each year. Each engine shall be tested, at the following loads (50%, 75%, ≥95%) or under conditions determined by the APCO to most challenge the emission control equipment. The APCO may waive some or all of the testing requirements if the results of previous compliance tests have demonstrated compliance with permitted emission limits by a sufficient margin. *[NCUAQMD Rule 102 §5.0]*

166. Permittee shall demonstrate compliance with permitted emission limits for Engines S-1 through S-10 while operating in Diesel Mode once every three years or following each 200 hours of operation of an individual engine in Diesel mode whichever is sooner. Compliance shall be demonstrated as indicated below using the following methods. All compliance tests shall be conducted while an engine is operated in Diesel mode at 50%, 75% or 95% or greater operating capacity of each engine; or under conditions determined by the APCO to most challenge the emission control equipment. Alternative test methods may be approved by the APCO *[NCUAQMD Rule 102 §5.0]*:

a. Particulate Matter - CARB Method 5 (front and back half), or EPA Methods 201a and 202.
b. Diesel Particulate Matter – CARB Method 5 (front half only)
c. Visible Emissions - U.S. EPA Method 9
d. Ammonia – Bay Area Air Quality Management NCUAQMD Method ST-1B
e. Reactive Organic Gases – ARB Method 100
f. Nitrogen Oxides -- ARB Method 100
g. Carbon Monoxide – ARB Method 100
i. CO shall be measured at the inlet and outlet of the oxidation catalyst.
h. Oxygen – ARB Method 100
i. Oxygen shall be measured at the inlet and outlet of the oxidation catalyst.
ii. Oxygen measurements shall be made at the same time as the CO measurements.
i. Liquid Fuel Sulfur Content – ASTM D5453-93

167. The engines shall be tested at various loads (50%, 75%, ≥95%) on a rotating basis, with one-third of the engines to be tested in diesel mode in each year; and tested at each of the three loads. The APCO may waive some or all of the testing requirements if the results of previous compliance tests have demonstrated compliance with permitted emission limits by a sufficient margin. The engines shall be tested on a rotating basis with all engines tested at the three different load values at least once every nine years; and that each engine is tested at a different

load each rotation. *[NCUAQMD Rule 102 §5.0]*

168. The Permittee shall demonstrate compliance with the hourly, daily, and annual ROC emission limits through the use of valid CO CEM data and the ROC/CO relationship determined by annual CO and ROC source tests; and APCO approved emission factors and methodology. *[40 CFR 63 Subpart ZZZZ; NCUAQMD Rule 102 §5.0]*

169. The Permittee shall demonstrate compliance with the hourly, daily, and annual SOx emission limits through the use of valid fuel use records, natural gas sulfur content, diesel fuel sulfur content, mass balance calculations; and APCO approved emission factors and methodology. The natural gas sulfur content shall be determined on a monthly basis using ASTM D3246. *[NCUAQMD Rule 102 §5.0, PSD]*

170. The Permittee shall demonstrate compliance with the hourly, daily, and annual PM emission limits, and the diesel particulate matter emission limits, through the use of valid fuel use records, source tests, and APCO approved emission factors and methodology. *[NCUAQMD Rule 102 §5.0, PSD]*

171. Relative accuracy test audits (RATAs) shall be performed on each CEMS at least once every twelve months, in accordance with the requirements of 40 CFR 60, Appendix B. Calibration Gas Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The NCUAQMD shall be notified in writing at least 30 days in advance of the scheduled date of the audits. Audit reports shall be submitted along with quarterly compliance reports to the NCUAQMD within 60 days after the testing was performed.

LOCAL ENFORCEABLE ONLY, EQUIPMENT SPECIFIC REQUIREMENTS

FUEL USAGE

172. The Emergency IC Diesel Generators S-11 and S-12 shall use one of the following fuels:
    a. CARB Diesel Fuel, or
    b. An alternative diesel fuel that meets the requirements of the Verification Procedure (as codified in CCR Title 13 Sections 2700-2710), or
    c. CARB Diesel Fuel used with fuel additives that meets the requirements of the Verification Procedure (as codified in CCR Title 13 Sections 2700-2710), or
    d. Any combination of a) through d) above.

EMISSIONS

173. The Permittee shall not discharge diesel particulate matter from reciprocating engines S-1 through S-10 while operating in Diesel Mode such that emissions of Diesel Particulate Matter exceed 0.15 g/bhp-hr. [*CCR Title 17 §93115*]

OPERATIONAL CONDITIONS

174. While operating the reciprocating engines S-1 through S-10 in Diesel Mode, the Permittee shall fire the engines for no more than 50 hours per year for each engine for Maintenance and Testing. [*CCR Title 17, §93115*]

175. The Emergency IC Diesel Generators S-11 and S-12 are authorized the following maximum allowable annual hours of operation as listed in Table 6.0 below *[17 CCR §93115] :*

Table 6.0 Hours of Operation for Emergency IC Diesel Generators S-11 & S-12

Emergency Use	Non-Emergency Use	
	Emission Testing to show compliance	Maintenance & Testing
Not Limited by the ATCM	Not Limited by the ATCM	50 hours/year

AMBIENT MONITORING

176. No later than 180 days after construction of the equipment authorized pursuant to this permit begins, and concurrent with the commencement of operation, the Permittee shall provide full funding for the purchase and installation of a new monitoring station (Shelter; CO, NOx, PM10/PM2.5, and other sampling equipment as determined by the APCO) to be installed at a location approved by the APCO. The funding shall include all costs associated with the purchase, installation, operation and maintenance (including personnel costs) of the monitoring station for an initial period of not less than five (5) years. PG&E shall reimburse the District for costs incurred within 30 days of receiving an invoice from the District. At the conclusion of that period, the APCO may extend the operation of the site if deemed in the best interest of the District, and PG&E will continue to fund all costs associated with its continued operation. The District shall manage the procurement, operation and maintenance of the site, and District staff will be responsible for collecting, securing, and quality assuring all data. *[District Rule 102 §5.0]*

177. No later than 180 days after construction of the equipment authorized pursuant to this permit begins, and concurrent with the commencement of operation, the Permittee shall provide full funding for the purchase and installation of a new meteorological monitoring station to be installed at a location approved by the APCO. The funding shall include all costs associated with the purchase, installation, operation and maintenance (including personnel costs) of the meteorological monitoring station for an initial period of not less than five (5) years. PG&E shall reimburse the District for costs incurred within 30 days of receiving an invoice from the District. At the conclusion of that period, the APCO may extend the operation of the site if deemed in the best interest of the District, and PG&E will continue to fund all costs associated with its continued operation. The District shall

manage the procurement, operation and maintenance of the site, and District staff will be responsible for collecting, securing, and quality assuring all data. The data collected at the station shall meet the requirements of EPA-454/R-99-005 "Meteorological Monitoring Guidance for Regulatory Modeling Applications" February 2000. *[District Rule 102 §5.0]*

INSIGNIFICANT EMISSIONS UNITS

The following systems are considered insignificant emissions units and are not subject to equipment specific requirements. However, these units are required to comply with all applicable Federal and Local Enforceable Only general requirements:

Exempt Equipment	Equipment Description	Basis for the Exemption
Air Conditioning Units	Comfort Air Conditioners	NCUAQMD Rule 200(d)(8)
Fuel Dispensing Facility		NCUAQMD Rule 200(d)(8)
Fuel Oil Service Tank #1		NCUAQMD Rule 200(d)(8)
Fuel Oil Service Tank #2		NCUAQMD Rule 200(d)(8)
Fuel Oil Storage Tank #1		NCUAQMD Rule 200(d)(8)
Fuel Oil Storage Tank #2		NCUAQMD Rule 200(d)(8)
Gasoline Storage		NCUAQMD Rule 200(d)(8)
Distilled Oil Storage Tank		NCUAQMD Rule 200(d)(8)
Lube Oil Tanks		NCUAQMD Rule 200(d)(8)
Oil/Water Separator		NCUAQMD Rule 200(d)(8)
Portable Sandblasting Unit		NCUAQMD Rule 200(d)(8)
Sandblasting and Print Facility		NCUAQMD Rule 200(d)(8)
Shop Cold Solvent Cleaner		NCUAQMD Rule 200(d)(8)
Unconfined Solvent and Paint Use	General Operations (facility wide)	NCUAQMD Rule 200(d)(8)
Welding Shop		NCUAQMD Rule 200(d)(8)
Wipe Cleaning Operations	General Operations (facility wide)	NCUAQMD Rule 200(d)(8)
Any equipment or activity not specifically identified by this Permit		NCUAQMD Rule 200(d)(8)

AUTHORIZING SIGNATURE

NORTH COAST UNIFIED AIR QUALITY MANAGEMENT DISTRICT

2300 MYRTLE AVENUE
EUREKA, CALIFORNIA 95501

PHONE (707) 443-3093
FAX (707) 443-3099

DATE: April 14th 2008

BY: _____

RICHARD L. MARTIN, JR.
AIR POLLUTION CONTROL OFFICER



Permit Seal

EXHIBIT 11

to Sierra Club Comments

National Park Service
U.S. Department of the Interior

Natural Resource Program Center

Federal Land Managers' Air Quality Related Values Work Group (FLAG)

Phase I Report—Revised (2010)

Natural Resource Report NPS/NRPC/NRR—2010/232





ON THE COVER

Courthouse Towers, Arches National Park, Utah.
Photo by Debbie Miller.

THIS PAGE:

Jumping Cholla, Superstition Wilderness, Arizona.
Photo by Steve Boutcher

Federal Land Managers' Air Quality Related Values Work Group (FLAG)

Phase I Report—Revised (2010)

Natural Resource Report NPS/NRPC/NRR—2010/232

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October 2010

The National Park Service, Natural Resource Program Center publishes a range of reports that address natural resource topics of interest and applicability to a broad audience in the National Park Service and others in natural resource management, including scientists, conservation and environmental constituencies, and the public.

The Natural Resource Report Series is used to disseminate high-priority, current natural resource management information with managerial application. The series targets a general, diverse audience, and may contain NPS policy considerations or address sensitive issues of management applicability.

All manuscripts in the series receive the appropriate level of peer review to ensure that the information is scientifically credible, technically accurate, appropriately written for the intended audience, and designed and published in a professional manner.

This guidance document was jointly prepared by the National Park Service, U.S. Forest Service, and the U.S. Fish and Wildlife Service, in collaboration with the Environmental Protection Agency. Guidance contained herein has been reviewed by subject matter experts and the general public through formal public review and comment period. This guidance document provides information for Federal Land Managers, permitting authorities, and permit applicants to use when assessing air quality impacts to air quality related values. Mention of trade names or commercial products does not constitute endorsement or recommendation for use by the U.S. Government.

This report is available from the Air Resources Division of the NPS (http://www.nature.nps.gov/air) and the Natural Resource Publications Management Web site (http://www.nature.nps.gov/publications/NRPM) on the Internet.

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NPS 999/105412, October 2010

United States Department of the Interior

OFFICE OF THE SECRETARY
Washington, D.C. 20240

OCT -7 2010

Dear FLAG User:

We are pleased to provide the final revised FLAG report (FLAG 2010). FLAG was formed at the request of permit applicants and State permit review authorities to develop a more consistent and objective approach for the Federal Land Managers (FLMs), *i.e.*, National Park Service, U.S. Fish and Wildlife Service, and U.S. Department of Agriculture Forest Service, to evaluate air pollution effects on their Air Quality Related Values (AQRVs). The FLAG effort focused on how air pollutants – primarily particulate matter, nitrogen dioxide, sulfur dioxide, nitrates, sulfates, ozone – affect the health and status of resources in areas managed by the three agencies. FLAG subgroups concentrated on four key issues: (1) visibility; (2) aquatic and terrestrial effects of wet and dry pollutant deposition; (3) terrestrial effects of ozone; and (4) process and policy issues. In December 2000, the FLMs published a final Phase I report (FLAG 2000). Based on knowledge gained and regulatory developments since FLAG 2000, the FLMs believe certain revisions to FLAG 2000 are now appropriate. The final revised FLAG 2010 report reflects those changes.

The FLAG 2010 report contains a wealth of information and should continue to be a very useful tool; we support its recommendations. The FLAG report is guidance and reflects agency direction, but it is not a rule. Nevertheless, we encourage all FLMs, permitting authorities, permit applicants, and other interested parties to take advantage of the helpful information contained in the FLAG report when assessing air pollution impacts on AQRVs.

We want to thank the many people who contributed to this important and worthwhile project.

Sincerely,

Thomas L. Strickland
Assistant Secretary for Fish and Wildlife and Parks
Department of the Interior

Sincerely,

Harris Sherman, Under Secretary
Natural Resources and the Environment
Department of Agriculture

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Preface to this Edition of the FLAG Phase I Report (New)

Under the Clean Air Act, the Federal Land Manager (FLM) and the Federal official with direct responsibility for management of Federal Class I parks and wilderness areas (i.e., Park Superintendent, Refuge Manager, Forest Supervisor) have an affirmative responsibility to protect the air quality related values (AQRVs) (including visibility) of such lands, and to consider whether a proposed major emitting facility will have an adverse impact on such values. The FLM's decision regarding whether there is an adverse impact is then conveyed to the permitting authority – usually a State agency – for consideration in its determinations regarding the permit. The permitting authority's determinations generally consider a wide range of factors, including the potential impact of the new source or major modification on the AQRVs of Class I areas, if applicable.

Both State permitting agencies and permit applicants requested that the FLMs provide better consistency pertaining to their role in the review of new source permit applications near Federal Class I areas. To address this concern, the FLMs formed the Federal Land Managers' Air Quality Related Values Work Group (FLAG). The official "FLM" is the Secretary of the department with authority over the Federal Class I areas (or the Secretary's designee). For the Department of the Interior, the Secretary has designated the Assistant Secretary for Fish and Wildlife and Parks as the FLM, whereas the Secretary of Agriculture has delegated the FLM responsibilities to the Regional Forester, and in some cases, the Forest Supervisor.

The purpose of FLAG is twofold: (1) to develop a more consistent and objective approach for the FLMs to evaluate air pollution effects on public AQRVs in Class I areas, including a process to identify those resources and any potential adverse impacts, and (2) to provide State permitting authorities and potential permit applicants consistency on how to assess the impacts of new and existing sources on AQRVs in Class I areas, especially in the review of Prevention of Significant Deterioration (PSD) of air quality permit applications. Under the Clean Air Act, the FLM formal "affirmative responsibility" role in the permitting process is limited to the extent a proposed new or modified source may affect AQRVs in a Class I area.[1]



Adult Brown Pelicans on Breton Island National Wildlife Refuge, Louisiana.
Credit: USFWS

FLAG members include representatives from three of the federal land management agencies that administer Federal Class I areas: the U.S. Forest Service (USFS), under the Department of Agriculture, and the National Park Service (NPS) and U.S. Fish and Wildlife Service (FWS) under the Department of the Interior, hereafter referred to as "the Agencies" or the "FLMs." In addition, five Tribal governments each administer their redesignated Class I areas, and the Bureau of Land Management (BLM) jointly administers four mandatory Federal Class I areas with the USFS. BLM is not a member of FLAG. However, because BLM does manage federal PSD Class I lands, as well as large amounts of acres in the vicinity of many FLAG Agencies' Class I areas, they may apply, when appropriate, the assessment methodologies outlined in the FLAG report. Applicants with the potential to adversely impact visibility or other AQRVs at PSD Class I areas administered by the BLM should contact that agency directly to discuss their considerations. The Agencies review permit applications for projects that may impact their areas, and make recommendations to their respective FLM as to whether or not those impacts might be considered adverse. The FLM will then make the final decision regarding the nature of the potential impacts to AQRVs, which is then conveyed to the permitting authority for its consideration.

In December 2000, after undergoing a public review and comment process that included a 90 day public comment period announced in the *Federal Register* and a public meeting, the FLMs published a *FLAG Phase I Report* (FLAG 2000), along with an accompanying "Response to Public Comments" document. The FLAG 2000 report described the work accomplished in Phase I of the FLAG effort. FLAG 2000 provided State permitting authorities and potential permit applicants a consistent methodology for conducting Class I area impact analyses. At that time, the Agencies envisioned a FLAG Phase II to address unresolved issues

1. Nevertheless, the FLMs are also concerned about resources in Class II parks and wilderness areas because they have other mandates to protect those areas as well. The information and procedures outlined in this document are generally applicable to evaluating the effect of new or modified sources on the AQRVs in both Class I and Class II areas, including the evaluation of effects as part of Environmental Assessments and/or Environmental Impact Statements under the National Environmental Policy Act (NEPA). However, FLAG does not preclude more refined or regional analyses being performed under NEPA or other programs.

including those that will require research and the collection of new data. However, resource constraints have prevented the Agencies from embarking on a formal FLAG Phase II process, but the Agencies have made significant progress in obtaining effects-based information as part of their resource-protection responsibilities. This information is included in this revised report.

The Agencies formed three separate subgroups to deal with area specific technical and policy issues associated with visibility impairment, ozone effects on vegetation, and effects of pollutant deposition on soils and surface waters. FLAG 2000 consolidated the results of those three subgroups.

FLAG 2000 included recommendations for completing and evaluating New Source Review (NSR) projects that may affect federally protected areas. It was intended to be a screening tool to help the Agencies and permit applicants determine whether impacts would be negligible. It was not intended to provide a bright-line test that would allow one to determine whether or not a proposed source of air pollution would cause or contribute to an adverse impact on AQRVs. That determination remains a project-specific management decision of the FLM. Among other factors, the FLMs' assessment of whether or not an adverse impact would occur is based on the sensitivity of the AQRVs at the particular federally protected area under consideration, and the magnitude, frequency, duration, timing, and geographic extent of the estimated new source impacts. This report (FLAG 2010) reaffirms these intentions.

FLAG 2000 has been a useful tool to the Agencies, State permitting authorities, and permit applicants. It was intended to be a working document that would be revised as necessary as the Agencies learn more about how to better assess the health and status of AQRVs. Based on knowledge gained and regulatory developments since FLAG 2000, the Agencies believe certain revisions to FLAG 2000 are now appropriate. This revised report (FLAG 2010) reflects those changes. However, it is important to emphasize that in this revision the Agencies have made certain changes to update specific information and data, but retain intact much of the background and general information contained in FLAG 2000 (e.g., Appendices A through H). Therefore, while this version replaces FLAG 2000, FLAG 2010 does not constitute a comprehensive update of all the information and material contained in FLAG 2000. Instead, the Agencies have focused their efforts on those areas of FLAG 2000 that have received the most attention and concern from permit applicants and permitting authorities. In that regard, the Agencies have included substantial changes to the visibility analysis sections, as well as included a more detailed discussion of the factors that the FLMs will use in the decision making process for an adverse impact determination. The Agencies have also taken this opportunity to discuss some key regulatory developments since FLAG 2000, as well as update some information in the FLAG 2000 deposition and ozone sections. To aid the FLAG user wanting to focus on the most recent changes, the Agencies have identified those new and revised sections throughout the FLAG 2010 report.

The most significant changes in this FLAG 2010 revision are summarized as follows:

- Adopts similar criteria derived from EPA's 2005 Best Available Retrofit Technology (BART) guidelines for the Regional Haze Rule to screen out from AQRV review those sources with relatively small amounts of emissions located a large distance from a Class I area (i.e., Q/D ≤ 10, for sources located greater than 50 km away).
- Utilizes the most recent EPA estimates to determine annual average or 20% best natural visibility conditions for Class I areas, using the new EPA-approved visibility algorithm.
- Adopts criteria derived from the 2005 BART guidelines that utilizes monthly average relative humidity adjustment factors to minimize the effects of weather events (i.e., short-term meteorological phenomena) on modeled visibility impacts.
- Adopts criteria derived from the 2005 BART guidelines that sets a 98th percentile value to screen out roughly seven days of haze-type visibility impairment per year.
- Includes deposition analysis thresholds and concern thresholds for nitrogen and sulfur deposition impacts on vegetation, soils, and water.
- Increases transparency and consistency of factors considered for adverse impact determinations.

A comparison of these FLAG 2010 changes to information contained in FLAG 2000 is provided in Table 1:

Other changes of note included in FLAG 2010 are:

- Clarifies the near field visibility analysis techniques for analyzing plumes or layers viewed against a background;
- Expands discussion of "Critical Loads" to reflect some significant developments in this area since FLAG 2000;
- Updates ozone sensitive species lists contained in Appendix 3.A of the FLAG 2000 report, but now includes that information on individual agency web sites rather than in the FLAG 2010 report;
- Replaces Appendix 3.B of FLAG 2000 (W126 and N100 ozone values) with current information on the individual agency web sites;
- Updates the information contained in Table D-2 of FLAG 2000 to reflect current information, but now includes that information on individual agency web sites rather than in the FLAG 2010 report;
- Replaces the dated sulfate, nitrate, and ammonium ion concentration maps (Figures D-2, D-3, and D-4 of FLAG 2000), with a reference to the NADP site for current trends data.

Table 1. FLAG 2000 vs. FLAG 2010 Analyses

	FLAG 2000	FLAG 2010
Annual emissions/Distance (Q/D) screening criteria. (Not applicable for Class I increment analyses).	None	≤10 (sum of certain pollutant emissions (TPY) divided by distance (km) from Class I area; applies to all AQRVs, not just visibility. See section 3.2.
Background Visibility Conditions.	Based on annual average natural, using NAPAP estimates.	Based on annual average natural, or 20% best natural, using EPA data from Regional Haze Rule development. See section 3.3.3.
Relative Humidity Adjustment Factor (f(RH)).	Hour-by-hour (with RH capped at 98%).	Monthly average (with RH capped at 95%). See section 3.3.3.
First Level Screening Model.	CALPUFF or CALPUFF-lite.	CALPUFF only. See section 3.3.3.
Visibility Assessment Criteria.	Maximum modeled value.	98th percentile modeled value at any receptor. See section 3.3.3.
Deposition Analysis Thresholds/ Concern Thresholds	None	Provided for nitrogen and sulfur deposition. See section 3.5.6.
Adverse Impact Determination Criteria.	"Likely to Object" if 10% threshold exceeded; regulatory factors implicitly considered.	Adverse impact determination process more explicit; considers regulatory and other factors. See sections 4.2-4.4

Executive Summary (Revised)

The Federal Land Managers' Air Quality Related Values Work Group (FLAG) formed to develop a more consistent approach for the Federal Land Managers (FLMs) to evaluate air pollution effects on resources. As discussed in the Preface, the *FLAG Phase I Report* (FLAG 2000) is being revised in part at this time. The primary—but not sole—focus of FLAG is the New Source Review (NSR) program, especially in the review of Prevention of Significant Deterioration (PSD) of air quality permit applications. The goals of FLAG have been to provide consistent policies and processes both for identifying air quality related values (AQRVs) and for evaluating the effects of air pollution on AQRVs, primarily in Federal Class I air quality areas, but also in some instances, in other national parks, national forests, national wildlife refuges, wilderness areas, and national monuments. Federal Class I areas are defined in the Clean Air Act as national parks over 6,000 acres and wilderness areas and memorial parks over 5,000 acres, established as of 1977. All other FLM areas are designated Class II. Maps of the Agencies' Federal Class I areas are provided in Appendix E.

FLMs have an "affirmative responsibility" to protect AQRVs. In this respect, the FLM role consists of considering whether emissions from a new or modified source may have an adverse impact on AQRVs and providing comments to permitting authorities (States or EPA). FLMs have no permitting authority under the Clean Air Act, and they have no authority under the Clean Air Act to establish air quality-related rules or standards. It is important to emphasize that the FLAG report only explains factors and information the FLMs expect to use when carrying out their consultative role. It is separate from Federal regulatory programs.

FLAG members include representatives from the three primary agencies that administer the nation's Federal Class I areas: the U.S. Forest Service (USFS), the National Park Service (NPS), and the U.S. Fish and Wildlife Service (FWS). (Subsequently in this report, these three agencies collectively will be referred to as "the Agencies" or the "FLMs." Class I and Class II air quality areas are called "FLM areas" in this report.) Appendix F contains a list of participants that worked on the original FLAG 2000 report.

This report describes the work accomplished in Phase I of the FLAG effort as revised to reflect current developments. That work includes identifying policies and processes common to the FLMs (herein called "commonalities") and developing new policies and processes using readily available information. This report provides State permitting authorities and potential permit applicants a consistent and predictable process for assessing the impacts of new and existing sources on AQRVs, including a process to identify those AQRVs and potential adverse impacts. The report also discusses considerations unrelated to new source review and managing emissions in Federal areas. If and when the Agencies embark on Phase II, FLAG will address unresolved issues including those that will require research and the collection of new data.



Marble Mountain Wilderness, California.
Credit: Steve Boutcher

This revised *FLAG Phase I Report* consolidates the results of the FLAG Visibility, Ozone, and Deposition subgroups. The chapters prepared by these subgroups contain issue-specific technical and policy analyses, recommendations for evaluating AQRVs, and information for completing and evaluating NSR permit applications. This information and the associated recommendations are intended for use by the FLMs, permitting authorities, NSR permit applicants, and other interested parties. The report includes background information on the roles and responsibilities of the FLMs under the NSR program.

This document includes recommendations for completing and evaluating NSR applications that may affect Class I FLM areas. This information can also be used to evaluate impacts on Class II parks and wilderness areas. It does not provide a universal formula that would, in all situations, allow one to determine whether or not a source of air pollution causes or contributes to an adverse impact. That determination remains a project-specific management decision, the responsibility for which remains with the FLM, as delegated by Congress. The FLM's assessment of whether or not an adverse impact would occur is based on the sensitivity of the AQRVs at the particular FLM area under consideration, as well as the consideration of several other factors, including the magnitude, frequency, duration, timing, and geographic extent of the new source's impacts.

To provide information for the FLM's assessment of adverse impacts on AQRVs, the permit applicant should identify the potential impacts of the source on all applicable AQRVs of that area. An FLM may ask that an applicant address any or all of the areas of concern. The primary areas of concern to the FLMs with respect to air pollution emissions are

visibility impairment, ozone effects on vegetation, and effects of pollutant deposition on soils and surface waters.

The *FLAG Phase I Report* also describes the FLAG effort, including the FLAG approach, organization, and plans for future FLAG work. Appendix A of the report contains a glossary of technical terms, abbreviations, and acronyms used in the report along with associated definitions. Appendix G provides a list of all references cited in the FLAG report.

The key recommendations developed by the Visibility, Ozone, and Deposition subgroups are summarized below, and updated in part in this FLAG 2010 revision. However, for all three subject matter areas, FLAG recommends that the permit applicant consult with the appropriate permitting authority and with the FLM for the affected area(s) for confirmation of preferred procedures. This consultation should take place in the early stages of the permit application process.

Recommendations for Evaluating Visibility Impacts (Revised)

FLAG provides recommendations, specific procedures, and interpretation of results for assessing visibility impacts of new or modified sources on Class I area resources.[2]

FLAG addresses assessments for sources proposed for locations near (generally within 50 km) and at large distances (greater than 50 km) from these areas. The key components of the recommendations are highlighted below.

In general, FLAG recommends that an applicant:

- Apply the Q/D test (see "INITIAL SCREENING TEST" below) for proposed sources greater than 50 km from a Class I area to determine whether or not any further visibility analysis is necessary.
- Consult with the appropriate regulatory agency and with the FLM for the affected Class I area(s) or other affected area for confirmation of preferred visibility analysis procedures.
- Obtain FLM recommendation for the specified reference levels (estimate of natural conditions) and, if applicable, FLM recommended plume/observer geometries and model receptor locations.
- Apply the applicable EPA Guideline, steady-state models for regions within the Class I area that are affected by plumes or layers that are viewed against a background (generally within 50 km of the source).
  - Calculate hourly estimates of changes in visibility, as characterized by the change in the color difference index (ΔE) and plume contrast (C), with respect to natural conditions, and compare these estimates with the thresholds given in section 3.3.3.
- For regions of the Class I area where visibility impairment from the source would cause a general alteration of the appearance of the scene (generally 50 km or more away from the source or from the interaction of the emissions from multiple sources), apply a non-steady-state air quality model with chemical transformation capabilities (refer to EPA's *Guideline on Air Quality Models*), which yields ambient concentrations of visibility-impairing pollutants. At each Class I receptor:
  - Calculate the change in extinction due to the source being analyzed, compare these changes with the reference conditions, and then compare these results with the thresholds given in section 3.3.3.
  - Utilize estimates of annual average natural visibility conditions for each Class I area as presented in Table 6, unless otherwise recommended by the FLM or permitting authority. Alternative estimates of visibility conditions are provided in Table 5 for consistency with State agencies that elected to use 20% best visibility for regional haze or BART implementations, or when FLMs recommend using the 20% best visibility as natural background.
- If first-level modeling results are above levels of concern, continue to consult with the Agencies to discuss other considerations (e.g., possible impact mitigation, more refined analyses).

This review process for distant/multi-source applications is portrayed schematically in Figure 1.

Recommendations for Evaluating Ozone Impacts (Revised)

- FLM actions or specific requests on a permit application will be based on the existing air pollution situation at the area they manage. These conditions include (1) whether or not actual ozone damage has occurred in the area, and (2) whether or not ozone exposure levels occurring in the area are high enough to cause damage to vegetation (i.e., phytotoxic O_3 exposures). Figure 2 shows the FLM review process to assess ozone impacts for a project that exceeds the initial annual emissions over distance (Q/D) screening criteria. As noted in Figure 2, ambient ozone concentrations are considered along with data from exposure response studies (EPA 2007b) to determine whether a source will cause or contribute to phytotoxic

2. Nevertheless, the FLMs are also concerned about resources in Class II parks and wilderness areas because they have other mandates to protect those areas as well. The information and procedures outlined in this document are generally applicable to evaluating the effect of new or modified sources on the AQRVs in both Class I and Class II areas, including the evaluation of effects as part of Environmental Assessments and/or Environmental Impact Statements under the National Environmental Policy Act (NEPA). However, FLAG does not preclude more refined or regional analyses being performed under NEPA or other programs.

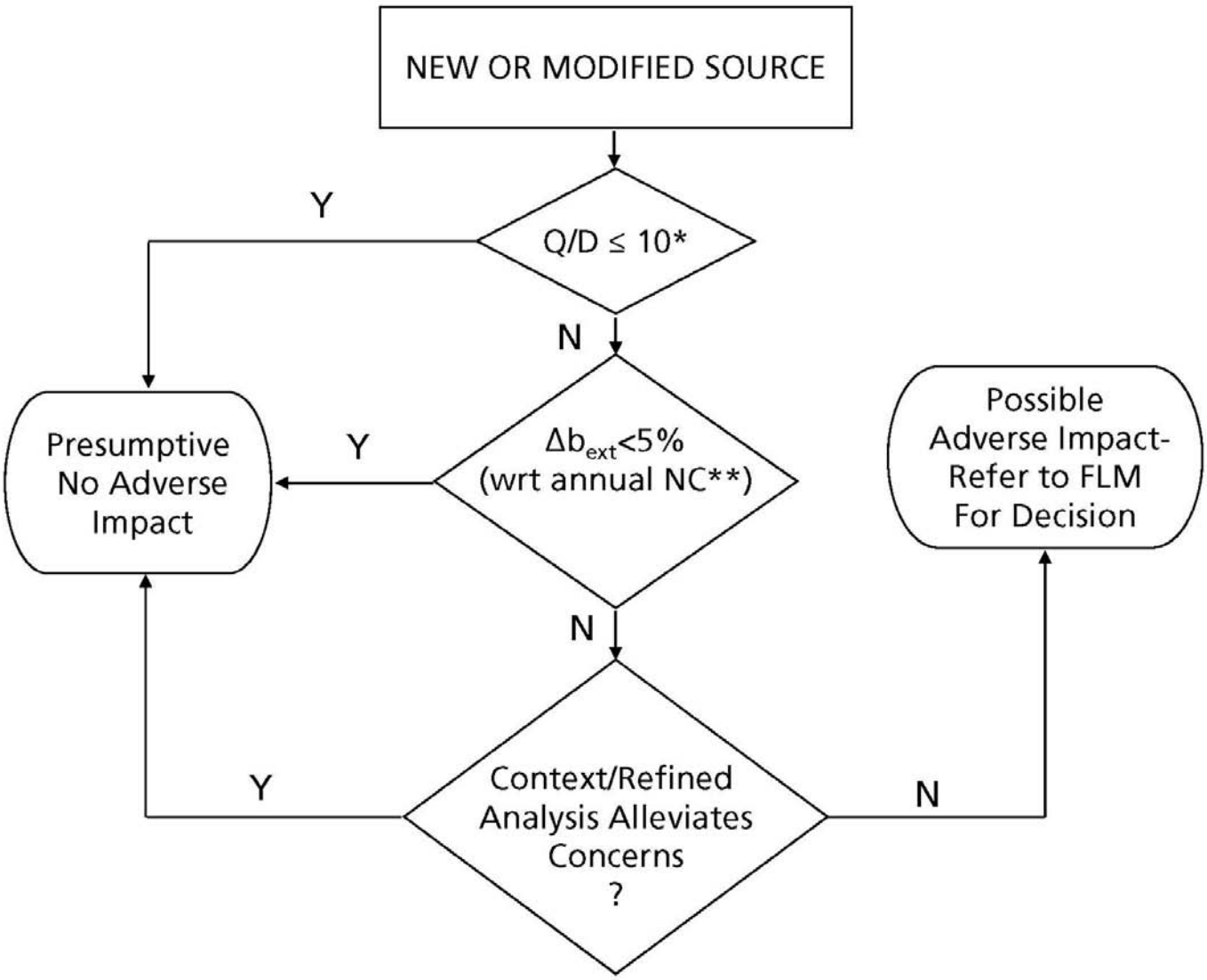


Figure 1. Procedure for Visibility Assessment for Distant/Multi-Source Applications (Revised)
*Q/D test only applies to sources located greater that 50 km from a Class I area.
**Difference Change in the 98th percentile with respect to (wrt) the annual average Natural Condition (NC). Applicant should use the 20th percentile best natural condition background if recommended by the FLM or permitting authority.

ozone levels (i.e., levels toxic to plants) at the affected site. The FLM may ask the applicant to calculate the ozone exposure values if these data are not already available. Ozone damage to vegetation is determined from field observations at the impacted site.

- Oxidant stipple necrosis on plant foliage and ozone-induced senescence infer adverse physiological or ecological effects, and are considered to be damage if they are determined to have a negative impact on aesthetic value.
- Established ozone metrics to describe ozone exposure are referenced.
- NO_x and VOC emissions are of concern because they are precursors of ozone. Current information indicates most FLM areas are NO_x limited. Until we determine the VOC or NO_x status of each area, we will focus on NO_x emission sources.

Recommendations for Evaluating Deposition Impacts (Revised)

For a project that exceeds the initial annual emissions over distance (Q/D) screening criteria, the permit applicant should consult with the appropriate regulatory agency and FLM for the affected area(s) to determine if a deposition impact analysis should be done (i.e., expected sulfur and/

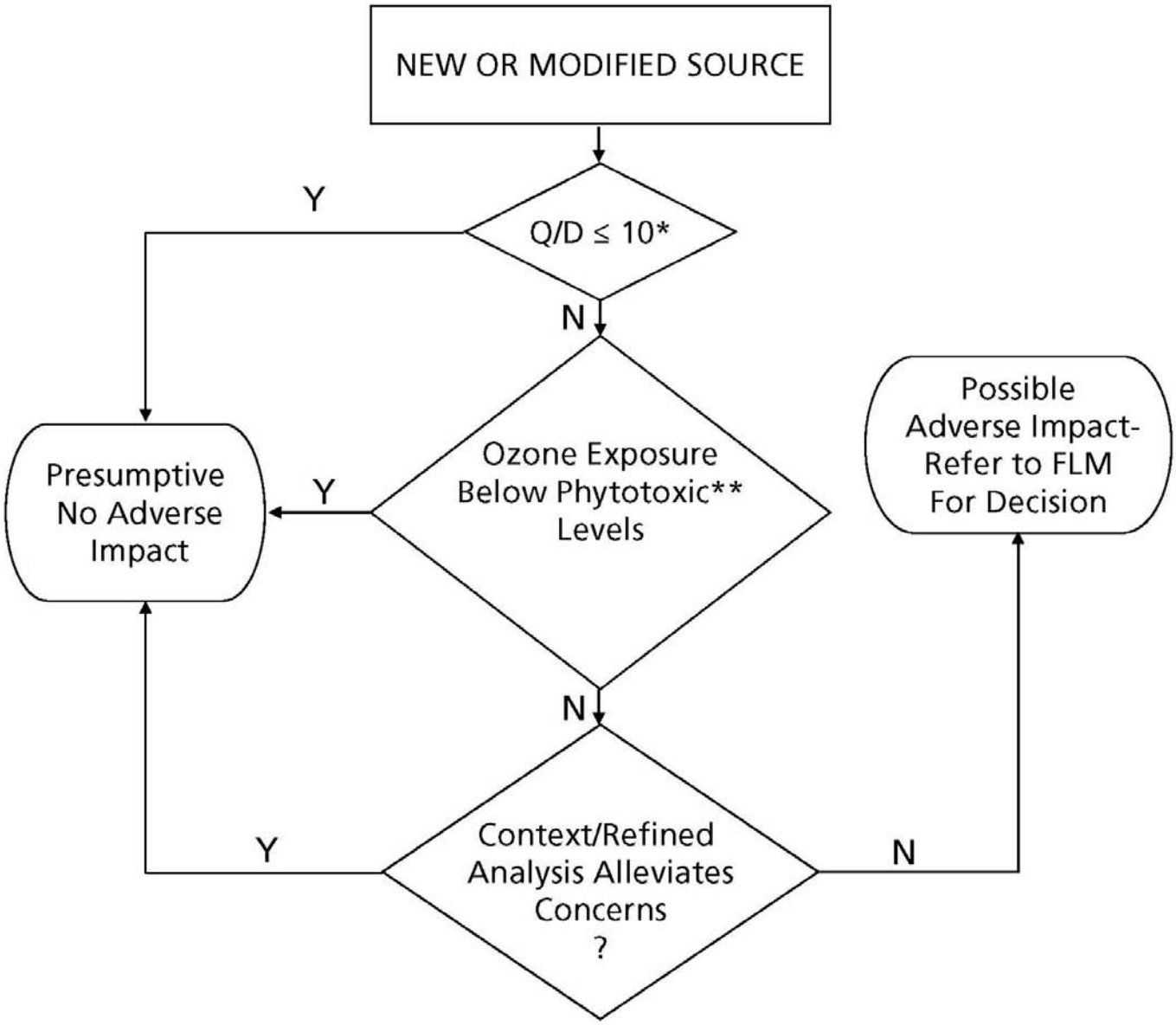


Figure 2. FLM Assessment of Potential Ozone Effects from New Emissions Source (Revised)
*Q/D test only applies to sources located greater that 50 km from a Class I area.
**Note: Ambient ozone concentrations are considered along with data from exposure response studies (EPA 2007b) to determine whether a source will cause or contribute to phytotoxic ozone levels (i.e., levels toxic to plants) at the affected site.

or nitrogen deposition impacts are above the Deposition Analysis Threshold (DAT) or concern threshold (see section 3.5.6). Please note that although mercury and other toxic emissions are of interest to the FLM, the deposition impact analyses discussed here applies only to nitrogen and sulfur emissions. If an analysis is advised, the permit applicant should obtain available information on Class I AQRVs, critical loads, and concern thresholds from the FLM. In addition, the applicant should refer to section 3.5.6 'Recommendations for Evaluating Potential Effects from Proposed Increases in Deposition to an FLM Area' section of the Deposition Chapter. The following steps summarize that process.

- From the respective Agency web sites, identify available on-site or representative wet and dry deposition data for the FLM area.
- Estimate the future deposition rate by adding the existing rate, the new emissions' contribution to deposition, and the contribution of sources permitted but not yet operating, while subtracting emission reductions that will occur before the proposed source begins operation. Modeling of new, reduced, and permitted but not yet operating emissions' contribution to deposition should be conducted following EPA recommendations.
- Compare the future deposition rate with the recommended screening criteria (e.g., critical load,

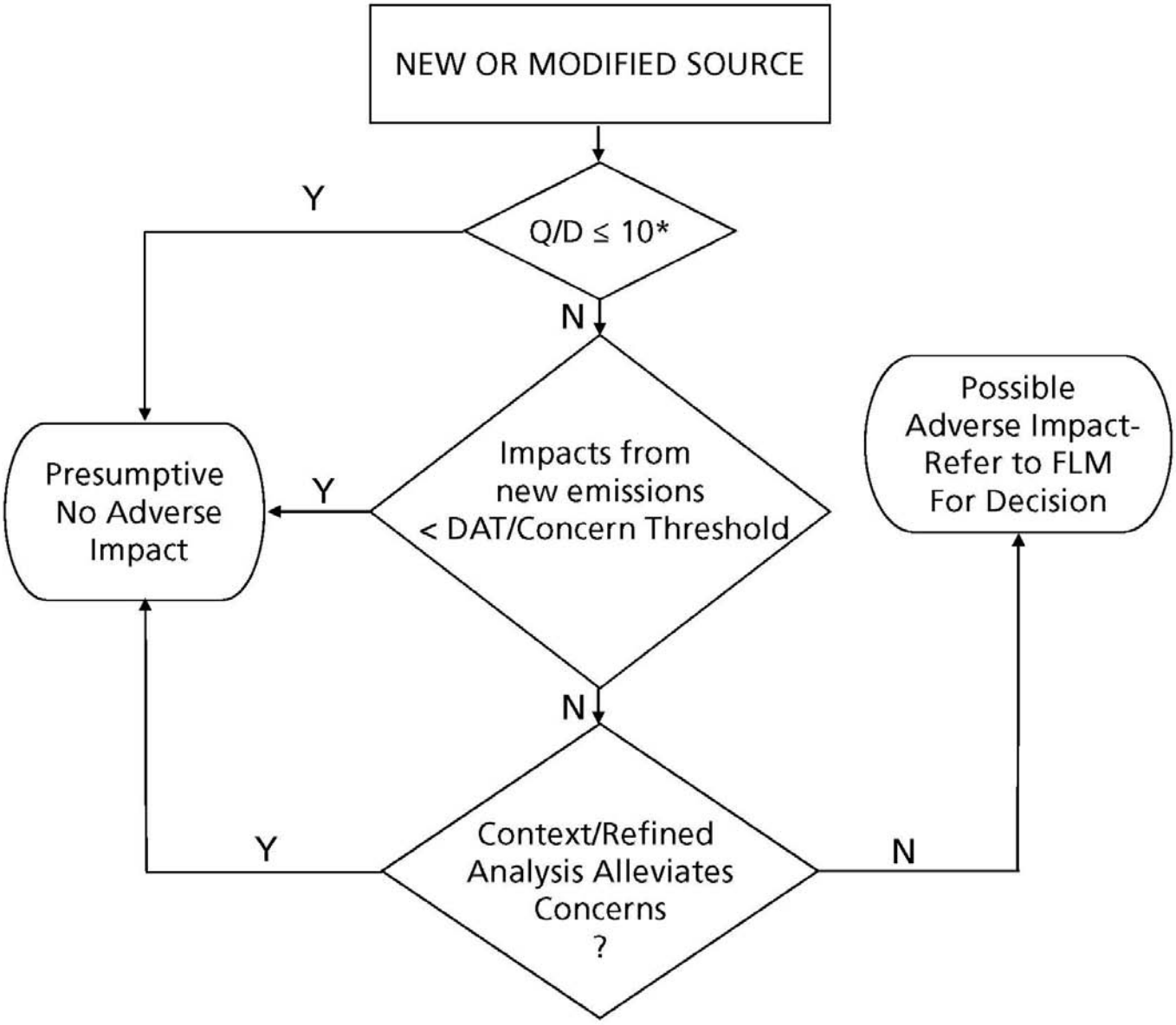


Figure 3. FLM Assessment of Potential Deposition Effects from New Emissions Sources (Revised)
*Q/D test only applies to sources located greater that 50 km from a Class I area.

concern threshold, or screening level value) for the affected FLM area. A list of documents summarizing these screening criteria, where available, can be found in Appendix G.

- Information for USFS Class I areas is also available at: http://www.fs.fed.us/air
- NPS and FWS Class I area information is available at: http://www.nature.nps.gov/air

- Figure 3 shows the FLM review process to assess deposition impacts from new emission sources.

1. Background

1.1. History (Revised)

The Clean Air Act Amendments of 1977 give Federal Land Managers (FLMs) an "affirmative responsibility" to protect the natural and cultural resources of Class I areas from the adverse impacts of air pollution (see Appendix B: 'Legal Framework for Managing Air Quality and Air Quality Effects on Federal Lands'). FLM responsibilities include the review of air quality permit applications from proposed new or modified major pollution sources near these Class I areas. If, in its permit review, an FLM demonstrates that emissions from a proposed source will cause or contribute to adverse impacts on the air quality related values (AQRVs) of a Class I area, the permitting authority, typically the State, can deny the permit.

The FLMs' role in the reviewing of permit applications focuses on impacts to Class I areas.[3] Individually, FLMs have developed different approaches to identifying AQRVs and defining adverse impacts on AQRVs in Class I areas. For example, in 1988, the U.S. Department of Agriculture Forest Service (USFS) conducted a national screening process to identify the AQRVs for each of its Class I areas. Using this national process as a starting point, each USFS Region refined the screening parameters and identified sensitive AQRVs for many Class I areas. However, this resulted in differences in the approaches and levels used by USFS Regions. The U.S. Department of the Interior National Park Service (NPS) and the U.S. Fish and Wildlife Service (FWS) have adopted a case-by-case approach to permit review, considering the most recent information available for each area. NPS and FWS have included lists of sensitive AQRVs for their Class I areas in their Air Resources Information System (ARIS) database.

1.1.1. FLAG Approach (Revised)

Air resource managers from the USFS, NPS, and FWS recognized the need for a more consistent approach among their agencies with respect to their efforts to protect AQRVs. In April 1997, an interagency Work Group was formed whose objective was "to achieve greater consistency in the procedures each agency uses in identifying and evaluating AQRVs." The Work Group named itself the



UL Bend National Wildlife Refuge, Montana.
Credit: Maribeth Oaks/The Wilderness Society

Federal Land Managers' Air Quality Related Values Work Group, or FLAG. Although FLAG membership comprises air resource managers and subject matter experts from the three agencies, representatives from the Bureau of Land Management, the U.S. Environmental Protection Agency (EPA), U.S. Geological Survey, and State air agencies have also participated in FLAG efforts.

FLAG participants have collaborated to:

- define sensitive AQRVs,
- identify the critical loads (or pollutant levels) that would protect an area and identify the criteria that define adverse impacts, and
- standardize the methods and procedures for conducting AQRV analyses.

To accomplish its objective, FLAG started with (and will continue to build on) the procedures, terms, definitions, and screening levels common to the three agencies. Many such "commonalities" were identified early in the FLAG planning sessions (see section 1.4, 'Commonalities Among Federal Land Managers').

FLAG's "Action Plan" stipulates a phased approach. Phase I addressed issues that could be resolved without research or the collection of new data. When the Agencies embark on FLAG Phase II, they will address the more complex and unresolved issues from Phase I that may require additional data collection (see section 5, 'Future FLAG Work').

The FLAG effort focuses on the effects of the air pollutants that could affect the health of resources in Class I areas, primarily pollutants such as ozone, particulate matter, nitrogen dioxide, sulfur dioxide, nitrates, and sulfates. In Phase I, FLAG concentrated on four issues: (1) terrestrial effects of ozone; (2) aquatic and terrestrial effects of wet and dry pollutant deposition; (3) visibility impairment; and (4) process and policy issues. Four subgroups, one for each of

3. Nevertheless, the FLMs are also concerned about resources in Class II parks and wilderness areas because they have other mandates to protect those areas as well. The information and procedures outlined in this document are generally applicable to evaluating the effect of new or modified sources on the AQRVs in both Class I and Class II areas, including the evaluation of effects as part of Environmental Assessments and/or Environmental Impact Statements under the National Environmental Policy Act (NEPA). However, FLAG does not preclude more refined or regional analyses being performed under NEPA or other programs.

these issues, were formed and charged with developing a set of recommendations for consistent policies and processes.

FLAG 2000's findings and technical recommendations underwent scientific peer review, as well as review by agency decision-makers such as Class I area Park Superintendents, Refuge Managers, and Forest Supervisors; Regional Foresters; and the Assistant Secretary for Fish and Wildlife and Parks. (Note: USFS has designated the FLM as the Regional Foresters and, in some cases, Forest Supervisors.) FLAG products have also undergone public review and comment. A "notice of availability" of the draft FLAG 2000 report was published in the *Federal Register*, and the FLMs conducted a public meeting to discuss the draft FLAG report and provided a 90 day public comment period. For the FLAG 2010 revisions, the FLMs announced the availability of the draft report in the *Federal Register* and provided a 60 day public comment period. There was not sufficient public interest to conduct a public meeting to discuss the proposed revisions to the FLAG report.

1.1.2. FLAG Organization

In addition to the four subgroups (policy, deposition, ozone, and visibility), the FLAG organization included Leadership and Coordinating Committees and a Project Manager. The Leadership Committee, which includes the air quality program chiefs from the three FLM agencies, was responsible for providing direction to the Work Group and the resources necessary for FLAG to accomplish its objective. The Coordinating Committee, which also includes representatives from each agency, was responsible for communications within the Work Group, including coordination among the agencies and subgroups. The FLAG Project Manager coordinated FLAG activities, served as a single point-of-contact for the subgroups, and performed other administrative functions.

1.2. Overview of Resource Issues (Revised)

Research conducted on Federal lands by FLMs and others has characterized natural resource effects associated with air pollution, and has helped identify those particular resources that are vulnerable to pollution in different areas. This effort does not address the impacts from air pollution on cultural resources. Documented effects include impairment of visibility, injury and reduced growth of vegetation, and acidification and fertilization of soils and surface waters. Air pollution effects on resources have been identified in a number of FLM areas; a few examples are provided below. It is important to note that similar, or even more serious, air pollution effects may be occurring on all Federal lands, but FLMs have not had the financial resources to perform the inventorying, monitoring, and/or research necessary to document such effects. Furthermore, the sensitivity of resources may vary from area to area because the nature of the resource, as well as geological, meteorological, biological, and other factors, vary from place to place.

1.2.1. Visibility

Visitors to national parks and wildernesses list the ability to view unobscured scenic vistas as a significant part of a satisfying experience. Unfortunately, visibility impairment has been documented in all Class I areas with visibility monitoring. Most visibility impairment is in the form of regional haze. The greatest visibility impairment due to regional haze occurs in the eastern United States and in southern California, while the least impairment occurs in the Colorado Plateau and Nevada Great Basin areas, and in Alaska. Ammonium sulfate contributes at least 50% to visibility impairment at most Class I areas in the eastern United States. The contribution to visibility impairment from ammonium nitrate is highest in central and southern California and in the Midwest. The largest region of high rural organic carbon visibility impairment is in the southeastern United States; impairment in this range is also present in the Sierra Nevada region of California and in the northern Rockies of Montana. The highest contribution to visibility impairment from fine soil is found in the arid Southwest. The highest coarse particle contribution to impairment is also in the arid Southwest and southern California. (DeBell et al. 2006) Visibility impairment on Federal lands can also result from plume intrusion and has been documented in Mount Zirkel Wilderness, Moosehorn National Wildlife Refuge, and Grand Canyon National Park.

1.2.2. Vegetation

While several components of air pollution (e.g., sulfur dioxide, nitrogen dioxide, and peroxyacyl nitrates) can affect vegetation, ozone is generally acknowledged as the air pollutant causing the greatest amount of injury and damage to vegetation. The most common visible effects are stipple (dark colored lesions on leaves resulting from pigmentation of injured cells), fleck (collapse of a few cells in isolated areas of the upper layers of the leaf, resulting in tiny light-colored lesions), mottle (degeneration of the chlorophyll in certain areas of the leaf giving the leaf a blotchy appearance), necrosis (death of tissue), and in extreme cases, mortality. Aside from visible injury, ozone exposure can result in less obvious physiological impairment such as decreased growth or altered carbon allocation.

Ozone fumigation experiments have identified a number of plant species that are sensitive to ozone. For example, fumigations were conducted in Great Smoky Mountains National Park (Tennessee and North Carolina) from 1987 to 1992. On the basis of foliar injury, thirty species were rated as sensitive to ozone levels that occurred in the park. The species with foliar injury included black cherry (*Prunus serotina*) and American sycamore (*Platanus occidentalis*). Additional observations and physiological measurements

indicated elevated ozone concentrations reduced leaf, root, and total dry weights, and increased the severity of leaf stipple and premature leaf abscission in these two species (Neufeld and Renfro 1993a,b). Field observations have documented foliar injury of these species in other eastern United States areas such as Brigantine Wilderness (New Jersey) and Cape Romain Wilderness (South Carolina).

Ponderosa pine (*Pinus ponderosa*) and Jeffrey pine (*Pinus jeffreyi*) are recognized as good candidates for ozone-injury surveys in the western United States, based on their documented sensitivity. For example, these species were examined for ozone injury in national parks and national forests in the California Sierra Nevada from 1991 to 1995. The sites surveyed included Lassen Volcanic, Yosemite, and Sequoia/Kings Canyon National Parks and the Tahoe, Eldorado, Stanislaus, Sierra, and Sequoia National Forests. Foliar injury attributable to ozone was found at all areas, and the extent of injury generally increased in a southward direction along the Sierra Nevada (Miller 1995).

1.2.3. Soils and Surface Waters

Acidity in rain, snow, cloud water, and dry deposition can affect soil fertility and nutrient cycling processes in watersheds and can result in acidification of lakes and streams with low buffering capacity. Deposition of sulfate to sensitive watersheds results in leaching of base cations, soil acidification, and surface-water acidification. In some soils, sulfate adsorption results in "delayed" acidification of surface waters. Deposition of excess nitrogen species (nitrate and ammonium) to both terrestrial and aquatic systems can result in acidifying streams, lakes, and soils. There is also evidence that nitrogen deposition can cause shifts in phytoplankton composition in lakes in which biological activity is limited by nitrogen availability, i.e., increased nitrogen deposition can cause phytoplankton species that use nitrogen more efficiently to eventually dominate the lake.

Water chemistry surveys and on-going monitoring show that many high elevation lakes on Federal lands in the Sierra Nevada, Cascades, and Rocky Mountains are sensitive to acid deposition. In general, these lakes are on bedrock that provides them with very little buffering capacity. Some of these lakes, for example, Loch Vale in Rocky Mountain National Park (Colorado) experience episodic acidification during Spring snow melt (Baron and Campbell 1997).

Through funding provided by the Southern Appalachian Mountains Initiative, Herlihy et al. (1996) compiled information on surface water sensitivity of streams in nine of the eleven Class I areas in the Southern Appalachians. The nine Class I areas were grouped according to geology, physiography, and stream chemistry, then the groupings were ranked in terms of effects. Class I areas in the West Virginia Plateau (Otter Creek and Dolly Sods Wildernesses) had the highest percentage of acidic stream length and lowest pH values. Class I areas in the Northern and Southern Blue Ridge (e.g., Shenandoah National Park in Virginia and Joyce Kilmer/Slickrock Wilderness in North Carolina) had a lower percentage of acidic stream length, however, streams with low buffering capacity were common. The Alabama Plateau Class I area (Sipsey Wilderness) had streams with the highest buffering capacity. (Note that the authors based their report on surveys conducted by others and did not account for potential differences in methods of data collection.)

A number of Federal areas contain estuarine and coastal areas that may experience eutrophication as a result of excess nitrogen deposition resulting from air pollution and other sources of nitrogen. For example, symptoms of eutrophication, including nutrient enrichment and algal blooms, have been observed in Everglades National Park and Chassahowitzka Wilderness (Florida).

1.3. Legal Responsibilities (Revised)

The specific legal responsibilities that Congress has given FLMs to protect natural, cultural, and scenic resources on the public lands from air pollution are identified in Appendix B. Statutes described in Appendix B include agency organic acts, the Wilderness Act, and the Clean Air Act (CAA).

The fundamental Congressional direction for managing public lands arises out of respective organic acts. Each of these laws is essentially a charter from Congress to the Executive Branch providing a purpose for parks, wildernesses, and refuges, respectively, and establishing broad management objectives for these areas. The Wilderness Act sets aside a subset of these public lands where natural processes are allowed to dominate. The agency stewards develop specific management objectives building on the organic acts using public involvement, regulations, best available science, and additional direction provided by Congress.

Among this additional Congressional direction is the Clean Air Act (CAA). It further characterizes some of the public lands as "Class I" areas and bestows on the land managers an affirmative responsibility to protect these areas from air pollution. The CAA directs that the FLMs identify and protect air quality related values, including visibility. This direction is consistent with the underlying charters provided by the organic acts and the Wilderness Act. The similarities of management objectives, and of the policies and procedures necessary for protecting Class I areas, are at the core of the FLAG process. Please note that although all wilderness is not Class I, and the FLMs have not proposed that non-Class I wilderness be classified as Class I, management actions (e.g., limiting human activities) that satisfy wilderness management objectives for Class II areas, are often substantially the same as those used in Class I area management.

In implementing laws, it is essential to understand the intent of Congress. In the case of the CAA, the FLM gleans additional insight from a passage in Senate Report No. 95-127, 95th Congress, 1st Session, 1977 which states:

> The Federal Land Manager holds a powerful tool. He is required to protect Federal lands from deterioration of an established value, even when Class I [increments] are not exceeded. . . . While the general scope of the Federal Government's activities in preventing significant deterioration has been carefully limited, the FLM should assume an aggressive role in protecting the air quality values of land areas under their jurisdiction. In cases of doubt the land manager should err on the side of protecting the air quality-related values for future generations.

Although the FLMs have an "affirmative responsibility" to protect AQRVs, they have no permitting authority under the CAA, and they have no authority under the CAA to establish air quality-related rules or standards. The FLM role within the regulatory context consists of considering whether emissions from a new source, or emission increases from a modified source, may have an adverse impact on AQRVs and providing comments to permitting authorities (States or EPA). It is important to emphasize that the FLAG report only explains factors and information the FLMs expect to use when carrying out their consultative role. It is not a rule or standard.

The FLAG report describes the steps and process that the FLMs intend to go through in order to perform their statutory duties. Consequently, the scope of the FLAG report is to provide a more consistent approach for the three FLM agencies to evaluate air pollution effects on resources, and to provide guidance to permitting authorities and permit applicants regarding necessary AQRV analyses. Although FLAG strives to be consistent with regulatory programs and initiatives such as the Regional Haze Rule and New Source Review Reform, no direct ties exist between FLAG and these regulatory requirements.

1.4. Commonalities Among Federal Land Managers

If a new source is proposed near two or more areas managed by different FLMs, the FLMs generally try to coordinate in their interactions with the permitting authority and with the applicant. For example, two or more FLMs involved in pre-application meetings typically try to minimize the workload for the applicant by reaching agreement on the types of analyses the application should contain. Beyond coordinating during permit review, FLMs currently base requests and decisions on similar principles regarding resource protection and FLM responsibilities. Listed below are the common principles in five areas of air resource management. In addition, Appendix C provides the FLM's 'General Policy for Managing Air Quality Related Values in Class I Areas.'

1.4.1. Identifying AQRVs (Revised)

FLMs agree on the following definition of an AQRV:

> A resource, as identified by the FLM for one or more Federal areas that may be adversely affected by a change in air quality. The resource may include visibility or a specific scenic, cultural, physical, biological, ecological, or recreational resource identified by the FLM for a particular area.

This definition is compatible with the general definition of AQRV that appears in the *Federal Register* (45 FR 43003, June 25, 1980). That definition includes visibility, flora, fauna, odor, water, soils, geologic features, and cultural resources. FLMs have the responsibility to identify specific AQRVs of areas they manage. To this end, FLMs further refine AQRVs beyond the above definition to be more site-specific (i.e., area specific) by using on-site information. To the extent possible, the FLMs have identified specific AQRVs for many Class I areas. Site-specific AQRV lists are available on the respective Agency web sites, or by contacting the Agencies directly. The FLMs also recognize that, ideally, inventories should be developed for all Class I areas. The FLMs may identify additional AQRVs in the future as more is learned through science about the sensitivity of resources to air pollution. A public process involving the regulated community and other interested members of the public is necessary and will be accomplished through participation in the land management planning process or reply to an announcement in the *Federal Register*. Finally, FLMs agree on the need for continued inventory, research, and monitoring to improve their ability to determine which AQRVs are most sensitive to air pollution and the sensitivity of these AQRVs.

1.4.2. Determining the Levels of Pollution that Trigger Concern for the Well-Being of AQRVs (Revised)

FLMs acknowledge the importance of being able to agree among themselves on the levels of pollution that trigger concerns for AQRVs. FLMs recognize the need to assess cumulative impacts and the difficulties associated with this process. Difficulties arise when a large number of minor source impacts eventually lead to an unacceptable cumulative impact or when a new source applies for a PSD permit in an area that has a high background concentration of pollution from existing sources. The agencies will evaluate a proposed new source within the context of the total impacts that are occurring or that potentially could occur from permitted/existing sources on the AQRVs of the area and should consider the effects of both emission increases and decreases.

1.4.3. Visibility

FLMs use EPA-approved models [Appendix W of Part 51 (EPA's *Guideline on Air Quality Models*, revised November 2005), as required under the PSD regulations at 40 CFR 51.166(1) and 52.21(1)] and the recommendations of the Interagency Work Group on Air Quality Modeling (IWAQM) to evaluate visibility impacts. The models use thresholds of visibility degradation measured in light extinction to evaluate source impacts to haze (far-field/multi-source impacts), and EPA established criteria for coherent plume impacts (near-field impacts). Currently all FLMs use Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring data to determine current conditions for visibility in FLM areas.

1.4.4. Biological and Physical Effects

All FLMs rely on research, monitoring, models, and effects experts to identify and understand physical, biological, and chemical changes resulting from air pollution and relating them to changes in AQRVs. Further, they focus on sensitive AQRVs (defined as either species or processes) to assess this biological/physical/chemical change.

1.4.5. Determining Pollution Levels of Concern (Revised)

FLMs rely on the best scientific information available in the published literature and best available data to make informed decisions regarding levels of pollution likely to cause adverse impacts. FLMs re-evaluate, update, and assess this information as appropriate. They consider specific Agency and Class I area legislative mandates in their decisions and, in cases of doubt, "err on the side of protecting the AQRVs for future generations." (Senate Report No. 95-127, 95th Congress, 1st Session, 1977)

For air quality dispersion modeling analyses, FLMs follow Appendix W of Part 51 (EPA's *Guideline on Air Quality Models*, revised November 2005), as required under the PSD regulations at 40 CFR 51.166(1) and 52.21(1), and the recommendations of the Interagency Work Group on Air Quality Modeling (IWAQM). FLMs recommend protocols for modeling analyses to permit applicants on a case-by-case basis considering types and amount of emissions, location of source, and meteorology. When reviewing modeling and impact analysis results, all FLMs consider frequency, magnitude, duration, location of impacts, and other factors, in determining whether impacts are adverse.

1.4.6. FLM Databases (Revised)

Air Resources Information System (ARIS) (Formerly Air Synthesis) (Revised)

ARIS provides information on air quality related values in NPS and FWS Class I areas, as well as in many NPS Class II areas. ARIS identifies specific AQRVs, and provides information on air quality and its effects in parks and wildernesses.

Natural Resource Information System – Air Module (NRIS-AIR) (Revised)

Publicly available USDA Forest Service Class I and II area information and related resource data can be linked to or found at http://www.fs.fed.us/air. If desired information and data cannot be found, contact any air program manager or specialist at national or regional offices for assistance.

1.5. Regulatory Developments Since FLAG 2000 (New)

Several regulatory developments have occurred since the FLMs published the FLAG report in December 2000. Some of these regulatory developments may have a significant effect on air resource management in mandatory Class I areas, or how these effects are assessed. First, on April 15, 2003, the Environmental Protection Agency (EPA) promulgated revisions to Appendix W of 40 C.F.R. §51 (*Guideline on Air Quality Models*). EPA revised the Guideline to adopt the CALPUFF model as a preferred long-range transport model for inclusion in Appendix A of that document. Prior to that date, FLAG 2000 relied on CALPUFF as the suggested model of choice for long-range transport assessments in accordance with recommendations of the Interagency Work Group on Air Quality Models (IWAQM). EPA's adoption of CALPUFF substantiates the Agencies' model choice. In addition, EPA's action, combined with improved computer technology, has resulted in the availability of more meteorological data. These improvements have enhanced the ability of permitting authorities and applicants to perform the types of modeling analyses suggested in FLAG. However, the FLMs will continue to work with the EPA on recommendations for future long-range transport model development.

On May 12, 2005, the EPA published the Clean Air Interstate Rule (CAIR) to reduce interstate transport of fine particulate matter and ozone. The CAIR applied to 28 eastern states and the District of Columbia, and required those areas to significantly reduce emissions of sulfur dioxide (SO_2) and/or nitrogen oxides (NO_x) from utilities. Although EPA developed the CAIR to address violations of the National Ambient Air Quality Standards (NAAQS) for fine particulates ($PM_{2.5}$) and ozone, the associated SO_2 and NO_x emission reductions would also benefit visibility and other AQRVs at many eastern Class I areas. The Agencies supported the CAIR, however, because it did not apply to western states, the majority of the Class I areas would not have directly benefited from the rule. Please note that at the time of this writing CAIR has been remanded to the EPA for revision to address various court challenges, and EPA has proposed a new transport rule as a replacement (EPA 2010a).

On July 6, 2005, the EPA published a final rule and associated guidelines that detail the Best Available Retrofit Technology (BART) requirements of the Regional Haze Rule. Among other things, the BART guidelines advise States to rely on the CALPUFF model for long-range visibility impairment assessments, provide thresholds for what constitutes causing or contributing to regional haze visibility impairment, and includes screening level values that exempt certain sources from further analysis. As discussed in more detail below, the Agencies believe the assumptions and methodology included in the BART guidelines also have merit with respect to evaluating haze-like visibility impairment for New Source Review under the PSD and other programs. Consequently, the Agencies are paralleling some of those BART guidelines in this FLAG revision.

Please note that FLAG 2000 acknowledges the EPA's July 1999 Regional Haze Rule, and discusses possible changes to FLAG that may be necessary as States implement the Regional Haze Rule. Although the EPA promulgated the Regional Haze Rule before the FLMs published FLAG 2000, there were several improvements and differences in the associated EPA guidance documents (e.g., those related to Natural Conditions and Tracking Progress) that were not finalized until December 2003. Therefore, these documents were not reflected in FLAG 2000, but have been considered in this revision. Currently, State Implementation Plans (SIPs) under the Regional Haze Rule are being developed, and submitted to the EPA for approval. If the new visibility SIPs adequately account for new source growth, the Agencies may need to make further revisions to the FLAG recommendations to reflect progress made through the SIP process that could minimize the focus the FLMs place on individual sources.

EPA has also developed other regulations, standards, and policies that will help reduce air pollution and resulting impacts at FLM areas (e.g., revised ozone, sulfur dioxide, nitrogen dioxide, and particulate matter standards; mobile source controls).

2. Federal Land Managers' Approach to AQRV Protection

FLM responsibilities for resource protection on Federal lands are clear and there should be no misunderstanding regarding the tools the FLM uses to fulfill these responsibilities. Opportunities to influence decisions regarding pollution sources external to the park or wilderness are limited. However, FLMs strive to minimize emissions from internal sources and their effects. Approaches for minimizing air pollution from external and internal sources are discussed in detail below.

2.1. AQRV Protection and Identification (Revised)

Congress assigned the FLMs an affirmative responsibility to protect AQRVs in Federal Class I areas. The FLMs interpret this assignment as a responsibility to:

- Identify AQRVs in each of the Class I areas.
- Establish inventorying and monitoring protocols for AQRVs.
- Prioritize AQRV inventorying and monitoring.
- Specify a process for evaluating air pollution effects on AQRVs, including the use of sensitive indicators.
- Specify adverse effects for each AQRV.

To the extent possible, AQRVs have been identified for each Class I area. As noted above, the FLMs may identify additional AQRVs in the future as more is learned about the sensitivity of resources to air pollution. The FLMs will provide a public process involving the regulated community and other interested members of the public in order to seek public input regarding AQRV-identification issues. This desired public involvement will be accomplished through participation in the land management planning process or reply to an announcement in the *Federal Register*.

While the sensitivity of an AQRV to air pollution may be known, long-term monitoring of the health or status of the AQRV may not have been accomplished. The expense of monitoring all AQRVs simultaneously is prohibitive. Consequently, FLMs seek opportunities through the permitting process and through partnerships to gather more information about condition of AQRVs.

Because AQRVs themselves are often difficult to measure, surrogates are used as indicators, or sensitive indicators, of the health or status of the AQRV. A working process for Class I area management and AQRV protection is outlined ahead in this document.

An adverse impact is determined for each AQRV. An adverse impact from air pollution results in a diminishment of



Sipsey Wilderness, Alabama.
Credit: Steve Boutcher

the Class I area's national significance, that is, the reason the Class I area was created. Adverse impacts can also be an impairment of the structure or functioning of the ecosystem, as well as an impairment of the quality of the visitor experience. The FLMs make an adverse impact determination on a case-by-case basis, based on technical and other information, which is then conveyed to the permitting authority.[4] The permitting authority then considers this, along with other factors, in its determination regarding the permit application.

2.2. New Source Review (Revised)

Section 165 of the CAA spells out the roles and responsibilities for FLMs in New Source Review, including the Prevention of Significant Deterioration (PSD) permitting program. Other laws, such as the respective agency organic acts and the Wilderness Act, provide the fundamental underpinning of land management direction to land managers. The following discussion merges this complex labyrinth of legal responsibilities as it relates to air resource management.

2.2.1. Roles and Responsibilities of FLMs (Revised)

The federal officials directly responsible for the national parks, national wildlife refuges, and national forests (e.g., park superintendents, refuge managers, and forest supervisors, respectively) derive their responsibility from the respective agency organic acts. Furthermore, these officials, and the FLM for the respective agencies, have an affirmative responsibility under Section 165 of the CAA to protect and

4. As discussed elsewhere in this report, if a proposed source's impacts on AQRVs exceed established significance criteria, the FLMs will consider the magnitude, frequency, geographic extent, etc. of the impacts, and other relevant factors, in determining whether or not the impacts are adverse.

enhance the AQRVs of Class I areas from the adverse effects of air pollution. The FLM for the USFS is the Regional Forester or the Forest Supervisor depending on the specific location. The FLM for the NPS and FWS is the Department of the Interior's Assistant Secretary for Fish and Wildlife and Parks.

The FLMs have visibility protection responsibility under 40 CFR §51.307 (New source review), which spells out the requirements for State Implementation Plan (SIP) visibility protection programs, as well as 40 CFR §52.27 (Protection of visibility from sources in attainment areas) and 40 CFR §52.28 (Protection of visibility from sources in non-attainment areas). These three provisions, taken together along with the SIP-approved rules, establish the visibility protection program for new and modified sources throughout the country.

Notification

Section 165 (42 USC 7475) of the CAA requires the EPA, or the State/local permitting authority, to notify the FLM if emissions from a proposed project may impact a Class I area. The permitting authority should forward PSD applications to the FLM for review and analysis as soon as possible after receipt, giving the FLM an opportunity to review the application concurrently with the permitting authority.

Generally, the permitting authority should notify the FLM of all new or modified major facilities proposing to locate within 100 km (62 miles) of a Class I area. In addition, the permitting authority should notify the FLM of "very large sources" with the potential to affect Class I areas proposing to locate at distances greater than 100 km. (Reference March 19, 1979, memorandum from EPA Assistant Administrator for Air, Noise, and Radiation to Regional Administrators, Regions I - X). Given the multitude of possible size/distance combinations, the FLMs can not precisely define in advance what constitutes a "very large source" located more than 100 km away that may impact a particular Class I area. However, as discussed elsewhere in this report, the Agencies have adopted a size (Q)/distance (D) criteria to screen out from AQRV review those sources with relatively small amounts of emissions located a large distance from a Class I area. Consequently, as a minimum, the permitting authority should notify the FLM of all sources that exceed this Q/D criteria. Nevertheless, the FLM and permitting authority should still work together to determine which other PSD applications the FLM is to be made aware of in excess of 100 km. In making this determination, the FLM and permitting authority should consider, on a case-by-case basis, such factors as:

- Current conditions of sensitive AQRVs;
- Magnitude of emissions;
- Distance from the Class I area;
- Potential for source growth in an area/region;
- Existing/prevailing meteorological conditions;
- Cumulative effects of several sources to AQRVs, as well as changes in their emissions.

Additionally, such dialogue facilitates coordination between permitting authorities and the FLMs. The significance of the impact to AQRVs is more important than the distance of the source. Not all PSD permit applications that the FLM is notified of will be analyzed in-depth by the FLM. FLM notification of a PSD permit application for a project located greater than 100 km does not mean that the permit application will be reviewed by the FLM in detail. Notification of PSD permit applications in excess of 100 km by the permitting authority allows the FLM to gauge the level of potential cumulative effects. As indicated above, the FLM decides which PSD permit applications to review on a case-by-case basis depending on the potential impacts to AQRVs.

Pre-Application Meetings

To expedite the PSD permit review process, the FLM encourages pre-application meetings with permitting authorities and permit applicants to discuss air quality concerns for a specific Class I area in question. Given preliminary information, such as the source's location and the types and quantity of projected air emissions, the FLM can discuss specific AQRVs for an area and advise the applicant of the analyses needed to assess potential impacts on these resources.

Completeness Determination

To further minimize delays, the FLMs encourage the permitting authority to use comments provided by the FLM concerning the completeness of the application, and to not deem the application complete until the applicant performs all necessary air quality impact analyses, including all relevant AQRV impact information. The permitting authority should then notify the FLM when they deem the application to be complete.

Visibility Protection Procedures

Additional procedural requirements apply when a proposed source has the potential to impair visibility in a Class I area (40 CFR §52.27(d)(2007); 40 CFR §51.307(a)(2007)). Specifically, the permitting authority must, upon receiving a permit application for a source that may affect visibility in any Class I area, notify the FLM in writing. Such notification shall include a copy of all information relevant to the permit application, including the proposed source's anticipated impacts on visibility in a Class I area. The permitting authority shall notify the FLM within 30 days of receipt and at least 60 days prior to the close of the comment period.

If the FLM notifies the permitting authority that the proposed source may adversely impact visibility in a Class I area, or may adversely impact visibility in a previously identified integral (scenic) vista, then the permitting

authority is to work with the FLM to address their concerns. If the permitting authority agrees with the FLM's finding that visibility in a Class I area may be adversely affected, the permit may not be issued. Even though the permitting authority may agree with the FLM's adverse impact finding regarding integral vistas, the permitting authority may still issue a permit if the emissions from the source are consistent with reasonable progress toward the national goal of preventing or remedying visibility impairment. In making this decision, the permitting authority may take into account the costs of compliance, the time needed for compliance, the energy and non-air quality environmental impacts of compliance, and the useful life of the source.

The FLM will make a preliminary determination regarding possible adverse visibility impacts upon receipt of all relevant information, including the draft permit and any associated staff analysis.

2.2.2. Elements of Permit Review

The FLM review of a PSD application for a proposed project that may impact a Class I area generally consists of three main analyses:

1. Air quality impact analysis to ensure that predicted pollutant levels in Class I areas do not exceed National Ambient Air Quality Standards (NAAQS) and PSD increments, and to provide sufficient information for the FLM to conduct an AQRV impact analysis. Ensuring that permit applicants meet these requirements is the direct responsibility of the permitting authority (see discussion below);
2. AQRV impact analysis to ensure that the Class I area resources (i.e., visibility, flora, fauna, etc.) are not adversely affected by the proposed emissions. The AQRV impact analysis includes interpreting the significance of the results from the applicant's air quality impact analysis and is the responsibility of the FLM (see discussion below); and
3. Best Available Control Technology (BACT) analysis to help ensure that the source installs the best control technology to minimize emission increases from the proposed project (See Appendix D for a summary of this analysis). The final BACT determination is a direct responsibility of the permitting authority.

Air Quality Impact Analysis

The permit applicant must perform an air quality impact analysis for each pollutant subject to PSD review (40 CFR §51.166). This analysis must show the contribution of the proposed emissions to increment consumption and to the existing ambient pollution levels in a Class I park or wilderness area. The applicant must perform a cumulative increment analysis for each pollutant and averaging time for which the proposed source will have a significant impact. Because proposed sources are not yet operating, the air quality analysis should rely on mathematical dispersion models to estimate the air quality impact of the proposed emissions. The FLMs provide the applicants with guidance on where to place model receptors within the Class I area. The applicant is responsible to provide sufficient information for the FLM to make a decision about the acceptability of potential AQRV impacts as a consequence of the new source.

The applicant must perform the air quality impact analysis using approved models and procedures as specified in Appendix W of Part 51 (EPA's *Guideline on Air Quality Models*, revised November 2005), as required under the PSD regulations at 40 CFR 51.166(1) and 52.21(1). The applicant should explicitly state all assumptions for the analysis, and furnish sufficient information on modeling input so that the FLM can validate and duplicate the model results. FLMs encourage the permit applicant to submit a modeling protocol for review before performing the Class I modeling analyses. This protocol should include the proposed air quality analysis methodology and model input (i.e., emissions, stack data, meteorological data, etc.), and the proposed location of the receptors in the FLM area.

AQRV Impact Analysis

According to the CAA's legislative history and current EPA regulations and guidance, the air quality impact analysis that provides sufficient information to enable the FLM to conduct the AQRV impact analysis is one part of a permit application just as are the BACT analysis and the air quality impact analysis relative to the increments and NAAQS. The applicant bears the entire cost of preparing the permit application including the complete air quality impact analysis.

It is important to highlight the distinction between the air quality impact analyses that the applicant performs and the AQRV impact analyses that FLMs perform. Whereas the permit applicant calculates changes in pollutant concentrations, deposition rates, or visibility extinction, the FLM assesses the extent to which these impacts affect sensitive visual, aquatic, or terrestrial resources. Given the FLM's statutory responsibilities and expertise, the FLM must have responsibility to consider whether the amount of pollution dispersed into the air or deposited on the ground (or in water) would have an adverse impact on any AQRV, and if so, to demonstrate that claim to the permitting authority. In making an adverse impact finding, FLMs consider such factors as magnitude, frequency, duration, location, geographic extent, and timing of impacts, as well as current and projected conditions of AQRVs based on cumulative impacts.

The FLM uses the results from the applicant's air quality impact analysis and other information to conduct the

AQRV impact analysis and make an informed decision about whether or not AQRVs will be adversely affected. If the FLM concludes that AQRVs will be adversely affected, the FLM will so demonstrate to the permitting authority. The following sections of this document give guidance to applicants on how to conduct an air quality impact analysis and how the FLM uses this information to make an AQRV impact decision.

Cumulative Impact Analysis

The FLM will evaluate on a case-by-case basis both the permit applicant's contribution to the AQRV impacts, as well as the cumulative source impacts on AQRVs, taking into account expected emission reductions. A cumulative air quality analysis in which the proposed source and any recently permitted (but not yet operating) sources in the area are modeled is an important part of any AQRV impact analysis. This cumulative modeled impact is then added to measured ambient levels (to the extent that such monitoring data are available) so that the FLM can assess the total effect of the anticipated ambient concentrations on AQRVs. If no representative monitoring data are available, the total pollutant concentrations should be estimated by modeling emissions from all contributing sources in the area.

Information Provided by the FLM to the Applicant

To assist the permit applicant in performing air quality impact analyses, the FLMs will provide all available information about AQRVs for a particular Class I area that may be adversely affected by emissions from the proposed source. FLMs will recommend available methods the applicant should use to analyze the potential effects (i.e., pollutant concentration, deposition rates, and visibility extinction) in the Class I area. In addition to identifying AQRVs, FLMs will, to the extent possible:

- identify inventories, surveys, monitoring data, scientific studies, or other published reports that are the basis for identification of AQRVs;
- identify specific receptors known to be most sensitive to air pollution and the pollutant or pollutants that individually or in combination can cause or contribute to an adverse effect on each receptor;
- identify the critical pollutant concentrations above which adverse effects are known or suspected to occur;
- recommend methods the applicant should use for predicting ambient pollutant concentrations and other related impacts (e.g., deposition, visibility) which may cause or contribute to an adverse effect on each receptor; and
- suggest screening level values or criteria that would be used to assess whether a proposed emissions increase would have a *de minimis* impact on AQRVs.

2.2.3. FLM Permit Review Process

The FLM's current permit review process for any application that may impact a FLM area is described below.

1. **Pre-application.** If possible, participate in any pre-application meeting to learn specifics of the proposed project (size, emissions, location, etc.) and to provide information regarding recommended Class I analyses.
2. **Modeling Protocol.** The FLMs encourage the permit applicant to submit a modeling protocol for review before performing the Class I modeling analyses. This protocol should include the proposed air quality analysis methodology and model input (i.e., emissions, stack data, meteorological data, etc.), and the proposed location of the receptors in the FLM area.
3. **Completeness Determination.** Upon receipt, the FLM will review the application and provide comments to the permitting authority regarding the completeness of the application and the need for additional information regarding the BACT, Air Quality Impacts, and AQRV Impacts analyses. The FLM will coordinate with the permitting authority and the permit applicant to ensure that all the necessary information to enable the FLM to make an impact determination is included.
4. **Public Comment Period.** After review of all relevant information, the FLM will provide pertinent comments to the permitting authority, before or during the official public comment period, and/or at scheduled public hearings.
5. **No Class I Increment Violated and No Adverse Impacts.** If no Class I increment is violated and no adverse impacts to AQRVs are expected, the FLM will inform the permitting authority of this determination and no further FLM action is necessary. The FLM may still provide BACT comments.
6. **No Class I Increment Violated but AQRV Impacts Uncertain.** If no Class I increment is violated but uncertainty exists regarding potential adverse impacts to AQRVs, the FLM may request that the permitting authority include a permit condition that requires the permittee to conduct relevant post-construction AQRV or air quality monitoring. The FLM may also request certain control technologies or methods to reduce impacts.
7. **Class I Increment Violated, but No Adverse AQRV Impacts.** If the Class I increment is violated, but no adverse AQRV impacts are anticipated, the applicant requests the FLM to "certify" no adverse impact under Section 165(d)(2)C)(iii) of the Clean Air Act [42 USC 7475(d)(2)(C)(iii)(1998)]. If the FLM concurs, (s)he makes a preliminary determination that no adverse impacts will occur.

- The FLM will inform the applicant, the State/local permitting authority, and EPA of the preliminary no adverse impact determination.
- The FLM will notify the public of its preliminary no adverse impact determination either through the permitting authority's notice procedures, or through separate notice in the *Federal Register*. Such notice should include a statement as to the availability of supporting documentation for inspection and copying, and an announcement of at least a 30 day public comment period on issues directly relevant to the determination in question.
- The FLM will review and prepare response to public comments.
- The FLM will make a final determination regarding no adverse impacts, with a clear and concise statement of reasons supporting that determination.
- The FLM will inform the permit applicant, the permitting authority, and EPA of its final determination and if the final determination is "no adverse impact," the FLM shall so "certify" in a letter to the affected parties.
- Simultaneous with above, the FLM will publish a final determination in the 'Notice' section of the *Federal Register*, including a clear and concise statement of reasons supporting that determination, statement as to availability of supporting documentation for inspection and copying, and statement as to immediate effective date (date signed) of final determination.
- The FLM will contact the permitting authority and request a revision to the State Implementation Plan (SIP) to eliminate the Class I increment violations.

8. **Adverse Impact Determination**. Regardless of increment status, the FLM may make a preliminary determination that the proposed project will cause, or contribute to, an adverse impact on AQRVs. Before officially declaring an adverse impact, the FLM will inform the proposed new source and the permitting authority that an adverse impact determination is imminent and suggest that the draft permit be modified. If the draft permit is modified to satisfy the concerns of the FLM, then an adverse determination is avoided.
   - The FLM will inform the applicant, the permitting authority, and EPA of a preliminary adverse impact determination.
   - The FLM will notify the public of the preliminary adverse impact determination either through the permitting authority's notice procedures, or through separate notice in the *Federal Register*. Such notice should include a statement as to the availability of supporting documentation for inspection and copying, and an announcement of at least a 30 day public comment period on issues directly relevant to the determination in question.
   - The FLM will review and prepare response to public comments.
   - The FLM will make a final determination regarding adverse impacts, with a clear and concise statement of reasons supporting that determination.
   - The FLM will inform the permit applicant, the permitting authority, and EPA of its final determination.
   - Simultaneous with above, the FLM will publish a final determination in the 'Notice' section of the *Federal Register*, including a clear and concise statement of reasons supporting that determination, statement as to availability of supporting documentation for inspection and copying, and statement as to immediate effective date (date signed) of final determination.
   - If the FLM makes a final determination that a source will have an adverse impact, the FLM will oppose the permit. However, the permit applicant may propose to mitigate any adverse impacts (via reducing emissions, obtaining emission offsets, etc.). If the applicant adequately mitigates the adverse impacts to the satisfaction of the FLM, the FLM will withdraw his objection to the permit. If the adverse impacts are not adequately mitigated and the permitting authority nevertheless issues the permit, the FLM may appeal the permit.

Note: If the permitting authority's SIP makes execution of the above listed steps impossible (e.g., inadequate time allotments for the FLM's determination or lack of timely FLM notice) the procedures shall be adjusted as appropriate. In addition, the above procedures (6 and 7) could also be modified to accommodate those situations when the FLM chooses to certify that existing impacts are adverse, absent a proposed new source. Such an action would alert potential permit applicants that adverse impacts exist and any new source would need to mitigate its potential impacts. Although each FLM may implement the above procedures somewhat differently, the FLAG goal is to reduce the differences in implementing the above steps.

Furthermore, FLMs intend to coordinate on air permit modeling requirements for new or modified sources that are geographically near more than one FLM area. For example, a proposed source in eastern Tennessee that lies equidistant from NPS-administered Great Smoky Mountains National Park and the FS-administered Joyce Kilmer/ Slickrock Wilderness would receive coordinated guidance on modeling requirements from the FLMs. The FLMs may or may not have common AQRVs at different Class I areas, making coordination beneficial. The FLMs may also

coordinate on potential permit conditions and mitigation strategies.

2.2.4. Criteria for Decision Making (Adverse Impact Considerations) (Revised)

As previously mentioned, the legislative history of the CAA provides direction to the FLM on how to comply with the affirmative responsibility to protect AQRVs in Class I areas, and in cases of doubt, the land manager should err on the side of protecting air quality-related values for future generations.

The FLMs define adverse impact on AQRVs as:

> An unacceptable effect, as identified by an FLM that results from current, or would result from predicted, deterioration of air quality in a Federal Class I or Class II area. A determination of unacceptable effect shall be made on a case-by-case basis for each area taking into account existing air quality conditions. It should be based on a demonstration that the current or predicted deterioration of air quality will cause or contribute to a diminishment of the area's national significance, impairment of the structure and functioning of the area's ecosystem, or impairment of the quality of the visitor experience in the area.

Also, the Federal visibility protection regulations (40 CFR §51.300, et seq., §52.27) define adverse impact on visibility as:

> [V]isibility impairment which interferes with the management, protection, preservation or enjoyment of the visitor's visual experience of the Federal class I area. This determination must be made on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency, and time of visibility impairment, and how these factors correlate with: (1) times of visitor use of the Federal class I area, and (2) the frequency and timing of natural conditions that reduce visibility. (Id. §51.301(a))

FLMs typically address adverse impacts on a case-by-case basis in response to PSD permit applications. The factors the FLMs will consider in making an adverse impact determination are discussed in more detail below (see section 4.3). When an adverse impact is predicted, FLMs recommend that permits either be modified to protect AQRVs or be denied. FLMs can also address adverse conditions outside of the PSD process. They do so through a variety of mechanisms: certify visibility impairment; participate in regional assessments; informally collaborate with States and EPA; review lease permits, SIP revisions, National Environmental Policy Act (NEPA) analyses, Park/Refuge/Forest management plans, CERCLA (Comprehensive Environmental Response, Compensation, and Liability Act) reviews, and other documents.

In some States, FLMs use screening procedures or thresholds that indicate when the condition of an AQRV is acceptable or unacceptable. The pollutant concentration or loading rate that will adversely impact an AQRV can vary among Class I areas, and depends on current conditions. After a threshold is reached, an increase in pollutant concentrations is likely to be unacceptable. A concern threshold can be an adverse impact threshold or other quantifiable level in resource condition or pollutant exposure identified by the FLM.

2.2.5. Air Pollution Permit Conditions that Benefit Class I Areas

The FLM does not determine what permit conditions will be required or administer permit conditions; that is the responsibility of the permitting authority. However, the FLMs may request permit conditions or agree to withdraw objections to permit issuance if requested conditions are included. The FLMs view the inclusion of certain PSD permit conditions by the permitting authority as a means to help protect or enhance the condition of AQRVs when:

1. Air pollution source(s) may cause impacts that exceed protection thresholds for AQRVs;
2. Terrestrial resources, aquatic resources, and/or visibility are currently adversely impacted by air pollution and proposed emissions will exacerbate these adverse conditions;
3. FLM policies require improvement or restoration of AQRVs in parks and wildernesses; and
4. There is uncertainty on the extent and magnitude of air pollution effects on AQRVs.

Recommended permit conditions may include requiring emission offsets, AQRV and/or air quality monitoring, inventories, post-construction reassessment, LAER (or other improved control technologies), or other measures to protect, enhance, or restore resources and values of parks and wildernesses. Permit conditions may:

1. Result in net air quality benefits at a protected area or within a region;
2. Contribute to a reduction of air pollution within a region;
3. Promote ecosystem inventories and/or monitoring to evaluate physical and biological resource damage caused by air pollution emissions; and
4. Promote ecosystem restoration or improve the condition of resources that have been damaged by air pollution emissions.

The basis of an air permit condition should be identified in the public notice for the draft permit. To be effective, permit conditions must be federally enforceable and guaranteed. Air permit provisions may be temporary or permanent depending on the nature of the permit requirements.

Procedures to implement an air permit condition must be acceptable to the FLM (e.g., an agreement between parties [memorandum of understanding, interagency agreement] is an option to accomplish inventory, monitoring, or other requirements).

2.2.6. Reducing Pollution in Nonattainment Areas (Nonattainment Permit Process)

The PSD program does not apply with respect to a particular pollutant when the source locates in an area designated non-attainment for that pollutant. Instead, pollution sources are regulated by Non-attainment Area New Source Review (NNSR). NNSR includes air quality planning and regulation of stationary sources. Air quality planning addresses issues such as lowest achievable emission rate (LAER), offsets, reasonably available control technology (RACT), and mobile and stationary source control strategies. New major stationary sources and major modifications of sources in designated non-attainment areas must satisfy NNSR before construction begins. For visibility protection, SIPs must include either EPA-approved provisions to comply with 40 CFR §51.307 for the non-attainment pollutant, otherwise, the federally promulgated visibility provisions at 40 CFR §52.28 would apply to all sources located in non-attainment areas. Therefore, FLMs can provide suggestions to the permitting authority regarding these conditions during the permitting and planning processes.

SIPs provide a mechanism to address AQRV impacts when the source or the Class I area is located in a non-attainment area. FLMs may recommend that States adopt policies, rules, or regulations in their SIPs requiring a demonstration that offsets will result in a net air quality benefit within any Class I area likely to be impacted by emissions from the source to be permitted. FLMs may also request emissions reductions greater than 1:1, perhaps offset rates of 1.5 or 2.0 to 1, or higher, depending on the nature and magnitude of impacts to be offset. Such recommendations can be developed jointly in a meeting with the regulatory authority or in a letter from the FLM.

Mitigation measures recommended by FLMs may include stringent control technologies to minimize the increase in emissions and the impact on AQRVs. Monitoring can determine whether predicted resource conditions are observed. Offsets ensure that net emissions reductions from all sources will occur within a geographic area and their resulting air quality impacts at the Class I area will be mitigated.

2.3. Other Air Quality Review Considerations (Revised)

At all Class I areas where visibility has been monitored, visibility conditions have been found to be impaired by human-caused pollution. The impairment comes primarily from older sources, not new sources. From a regional perspective, new or modified sources (using new/cleaner technologies) contribute far less to impaired AQRV conditions than old sources. EPA has implemented a call for reducing NO_x emissions from older sources in the eastern U.S. to meet existing ozone standards. In addition to complying with national ambient standards, States are now developing plans to implement EPA's Regional Haze Regulations. If these requirements are implemented, then progress toward remedying impaired AQRVs is likely. However, given the sensitivity of some AQRVs to low levels of pollution, programs focused on reaching national goals, such as the NAAQS or visibility, may not fully remedy impacts on AQRVs in all locations. It is for this reason that the FLM does pursue other strategies to protect AQRVs. The following sections discuss FLM issues that go beyond NSR.

2.3.1. Remedying Existing Adverse Impacts

Allowing the existence of adverse impacts would be inconsistent with the mandates of the FLM agencies. Consequently, FLMs may request or participate in regional assessments to protect AQRVs, and remedy any existing adverse impacts on AQRVs, as appropriate. Regional assessments often use a multi-faceted approach to remedy impairment. For example, categories addressed by the Grand Canyon Visibility Transport Commission (GCVTC) include air pollution prevention; clean air corridors; stationary sources; sources in and near Class I areas; mobile sources; road dust; fire; and future regional coordination.

Clean Air Act requirements for remedying existing visibility impairment provide a mechanism for addressing impacts from specific sources or groups of sources [42 USC 7491). Negotiations at the Centralia Power Plant in the state of Washington provide an example of how to build partnerships and work collaboratively to obtain retrofit controls or more stringent control technologies for sources that affect a FLM area. Through a collaborative decision making process, owners of the Centralia plant agreed to reduce sulfur dioxide emissions at the plant by 90%. In another case, the FWS identified plume impacts from a pulp and paper mill located seven miles upwind of the Moosehorn Wilderness Area. Using cameras provided by the IMPROVE monitoring network, plumes from the mill were documented entering the Moosehorn Wilderness Area. In collaboration with the State of Maine, additional controls for nitrogen oxides and updated particulate controls were incorporated into the mill's PSD permit to address the plume impacts.

FLMs may also coordinate with others to ensure that emission reductions in nonattainment areas will improve air quality in FLM areas. Recommendations on urban planning were developed with FLM involvement to address nonattainment areas in California. Data documenting ozone effects on vegetation were provided to the planning authority.

2.3.2. Requesting State Implementation Plan (SIP) Revisions to Address AQRV Adverse Impacts (Revised)

A SIP is the mechanism that states use to develop the pollution control programs that will be used to achieve and maintain the NAAQS, as well as prevent significant deterioration of air quality. It is important for FLMs to be involved in SIP development, as participation provides an opportunity to influence planning of pollution control programs that can benefit air quality in FLM areas. Once a SIP is fully approved by EPA, it is legally enforceable under both State and Federal law. FLMs assist in the development of SIPs by providing analysis and comment to address existing impacts of concern. This approach is particularly useful for addressing impacts on AQRVs other than visibility, since the Clean Air Act does not provide specific requirements for other AQRVs.

SIP revisions could be used to address multiple sources and regional pollution that adversely affect AQRVs in all Class I areas. For example, in South Coast and San Diego, California, SIP revisions included FLM recommendations to reduce the impact of minor sources on AQRVs. South Coast recommendations addressed visibility while the San Diego recommendations addressed all AQRVs. EPA's NO_x SIP Call in the east is another example of obtaining emission reductions through the SIP revision process. The NO_x SIP Call was directed at 20 eastern States and the District of Columbia to address NO_x emissions from existing large sources. Significant reductions in ozone formation and nitrogen deposition have occurred as a result of these efforts.

2.3.3. Periodic Increment Consumption Review (Revised)

EPA has indicated its intention to establish a SIP revision requirement to address existing adverse impacts on AQRVs. The FLMs strongly support EPA exercising its authority in this way. In the interim, however, there are existing SIP revision requirements that are not being fully utilized. EPA's current regulations require States to conduct a periodic review of the adequacy of their PSD plan and program. [40 CFR §51.166(a)(4)] This would include an assessment of increment consumption in Class I and Class II areas. Few States have ever conducted a comprehensive, cumulative increment consumption analysis for one or more Class I areas. In addition, many PSD sources have not exceeded the significant impact levels for increment consumption; thus, few PSD permit applicants have had to perform a cumulative increment consumption analysis for Class I areas. Such a periodic increment consumption review would be beneficial given that the burden of proof for AQRV adverse impact determinations shifts from the FLM to the applicant when the increment has been consumed.

In its 1990 report, *Air Pollution: Protecting Parks and Wilderness From Nearby Pollution Sources,* the U.S. General Accounting Office (GAO) found that only 1 percent of the sources within 100 kilometers of five Class I areas it investigated were required to have permits under the PSD program, with 99 percent of the sources being minor or grandfathered sources. It also found that "non-PSD sources contribute from 53 to 90 percent of five of the six criteria pollutants emitted within a 100-kilometer radius of each of the five Class I areas." As part of its investigation, GAO noted that "a significant portion of total emissions of volatile organic compounds generally comes from small sources...and suggested that as part of the overall control strategy, States may want to consider lowering thresholds for regulating new sources to 25 tons of volatile organic compounds a year." According to the investigation, 55 percent of anthropogenic VOC emissions come from new sources or modifications totaling five tons per year or less. In a review of PSD permit applications near Mesa Verde National Park (a Class I area in Colorado), a cumulative modeling analysis of increment-consuming sources found that approximately 80 percent of the NO_2 Class I increment at the park had been consumed, but much of it by minor sources.

The FLMs have encouraged EPA to provide clearer direction on how often these periodic reviews should occur as the lack of a prescribed time-frame for conducting such analyses has clearly led to noncompliance with this requirement over the past twenty years by States.

2.4. Managing Emissions Generated in and Near FLM Areas (Revised)

Specific strategies need to be developed and implemented for reducing and preventing pollution from the many diverse sources and activities in communities surrounding FLM areas, including "gateway" communities (i.e., those adjacent to FLM areas). Accountability mechanisms are needed to ensure that appropriate actions are taken, reported and incorporated into SIPs, visibility protection plans, and Federal land management plans. Various forums (e.g., the Western Regional Air Partnership, and the Southern Appalachian Mountains Initiative) addressed some of the emissions sources of concern and developed regional strategies. In addition, EPA has formed other "regional planning organizations" for implementing its regional haze rule. FLMs participate in these forums, consistent with Federal law (e.g., Federal Advisory Committee Act), to the

maximum extent possible and coordinate their activities within those forums to ensure that comprehensive strategies are developed and implemented to address all the key emissions sources near FLM areas.

A systematic assessment of emission sources in and near FLM areas would be extremely helpful for formulating strategies aimed at mitigating or eliminating adverse impacts on area resources, and the NPS has performed micro-emission inventories for several of its Class I areas. However, without this assessment for all areas it is not possible to accurately quantify the extent to which these emissions contribute to the overall problem. Nevertheless, FLMs can, and should, take steps to minimize emissions generated on FLM lands even without an accurate inventory of emissions sources.

2.4.1. Prescribed Fire

Prescribed fire is a land management tool used for multiple landscape objectives. Prescribed fire allows the FLM to mimic natural fire return intervals under controlled conditions where smoke management can minimize air quality impacts. The alternative is wildfires, which can be very difficult to control and may cause much more severe air quality impacts. A modeling assessment suggests that using prescribed fire to minimize wildfires can result in a net reduction in fine particle ($PM_{2.5}$) emissions in the long-term. In the Pacific Northwest wildfire emissions were found to be greater than prescribed fire emissions in the same airshed (Ottmar 1996).

Since the early 1900s, wildfire has been aggressively suppressed on most of the nation's public lands to protect public safety, property, and to prevent what was thought to be the destruction of our natural and cultural resources. Fire-exclusion practices have resulted in forests, shrub lands, and grasslands plagued with a variety of problems, including overcrowding, resulting from the encroachment of species normally suppressed by fire; vulnerability of trees to insects and disease; and inadequate reproduction of certain species. In addition, heavy accumulation of fuels (such as dead vegetation on the forest floor) can cause fires to be catastrophic, which threatens firefighter and public safety, impairs forest and ecosystem health, destroys property and natural and cultural resources, and degrades air quality. The intense or extended periods of smoke associated with wildfires can also cause serious health effects and significantly decrease visibility.

FLMs recognize prescribed fire as a valuable tool; they also recognize that emissions from prescribed fire can be a significant source of air pollution. Smoke particles are also in the size range (< 2.5 µm) that they play a significant role in visibility impairment. Particulate matter is the main pollutant of concern from smoke because it can cause serious health problems, especially for people with respiratory illness. The FLMs are committed to minimizing the impacts from smoke by following sound smoke management practices, and if practical, using non-burning alternatives (i.e., mechanical clearing, chipping, mulching) to achieve land management objectives. Each prescribed burn site will have unique characteristics, but in general, smoke impacts can be minimized by burning during weather conditions that provide optimal humidity levels and dispersion conditions for the type of materials being burned, in addition to limiting the amount of materials and acreage burned at one time.

EPA has worked in partnership with land management agencies in the U.S. Departments of Agriculture, Defense, and the Interior; State Foresters; State air regulators; Tribes; and others to obtain recommendations and develop a national policy that addresses how best to improve the quality of wildland ecosystems (including forests and grasslands) and reduce threats of catastrophic wildfires through the increased use of managed fire, while achieving national clean air goals (EPA 1998b). EPA's interim air quality policy on fire describes criteria for wildland managers (federal, state, tribal, and private), and state and tribal air pollution agencies, to use in planning for and implementing prescribed fires, and recommends a variety of smoke management techniques that land managers can use to help reduce smoke impacts from prescribed fires. The policy is available at EPA's web site: http://www.epa.gov/ttn/faca/fa08.html. In addition, on March 22, 2007, EPA promulgated its Exceptional Events Rule that clarifies how ambient air quality standard exceedances from wildland fire will be treated in determining attainment and nonattainment status. In that rule, EPA committed to revising its 1998 wildland fire policy (72 FR 13560, March 22, 2007).

2.4.2. Strategies to Minimize Emissions from Sources In and Near FLM Areas (Revised)

Aside from prescribed fire, other activities in and near FLM areas that generate air pollution include vehicle emissions, road building, operation of generators, oil and gas development, etc. Developing strategies for addressing natural resource impacts in or near an FLM area should not only take into consideration the type of activities generating the emissions and their amount, but also the existing condition of the resources of that area. More stringent measures should be recommended for sources in and near FLM areas that are already experiencing adverse effects from air pollution.

Examples of potential air pollution prevention practices that FLM agencies may encourage or develop and use are categorized under the following three strategies:

Pollution Prevention Strategies

- Review land management plans for affected FLM areas to assess whether they include strategies to limit and reduce air pollution emissions and incorporate protective measures into planning and decision documents.
- Place priority on pollution prevention.
- Encourage zero and near-zero emitting technologies.
- Promote energy conservation and the use of renewable energy sources.
- Promote use of clean fuels.

Mobile Source Strategies

- Promote the adoption of Low Emission Vehicle standards or the conversion of Federal fleets to alternative fuels.
- Improve control of evaporative emissions.
- Promote more stringent emission standards for the tour bus industry and other high-emitting vehicles used in federal areas (e.g., park shuttle vehicles).
- Considering restricting access of high emitting vehicles to sensitive areas.
- Retire high-emitting vehicles from Federal fleets as quickly as practicable and/or relocate high-emitting vehicles to less sensitive areas until they can be retired.
- Establish emission budgets from the transportation sector for selected FLM areas.
- Develop mass transit systems in some NPS units (e.g., light rail in Grand Canyon NP and a bus system in Zion NP).

Minor Source Strategies (Revised)

- Apply RACT, BACT, LAER, best and reasonably available control measures, etc., to existing federal sources, as appropriate.
- Recommend going beyond conformity requirements to include the protection of AQRVs in FLM areas, and ensure all actions FLMs can practicably control in and near FLM areas will not cause, or contribute to, an adverse impact on any AQRV.

Improved involvement with interested parties in gateway communities will likely be required to ensure growth in these communities occurs in a manner that mitigates the impact on natural resources. These communities may need to enhance their participation in the planning processes of FLMs. Similarly, FLMs should participate in planning activities for public lands located in the FLM area and communities adjacent to FLM areas to ensure air quality concerns are adequately addressed. Mechanisms should be identified and developed for community involvement in developing, implementing, and enforcing emission management strategies for sources near and in FLM areas.

Implementing strategies to achieve emission reductions in and near FLM areas will require efforts in at least three specific areas:

1. FLMs should ensure that sufficient emphasis is placed in agency planning documents requiring the minimization of air pollution emissions from new activities or practices.
2. FLMs should inventory air pollution emissions within FLM areas. After emissions have been quantified, FLMs, States, and adjacent communities will be able to assess the impact of these emissions through the use of appropriate models. Knowledge of Class I area emissions will also improve FLM ability to consult with States during the development and review of their SIPs (especially visibility SIPs). The NPS has developed an emissions inventory tool, the Climate Leadership in Parks (CLIP) Tool, that can be utilized by FLMs to inventory both greenhouse gases and all criteria air pollutants.
3. FLMs should cooperate with States and local communities in assessing the need for, and the development of, appropriate emission reduction strategies in and near FLM areas that address non-PSD sources. For Class I areas, the Regional Planning Organizations have completed analyses of emissions from nearby communities and activities that will serve as the basis for identifying strategies to reduce emissions. Without an acknowledgment from States and local communities that these sources may pose a threat to FLM areas and a systematic assessment of these potential impacts, current efforts to protect FLM area resources may be insufficient.

2.4.3. Conformity Requirements in Nonattainment Areas

Conformity criteria and procedures ensure that actions on lands administered by Federal agencies do not cause a violation of the NAAQS, increase the frequency of any standards violations, or delay attainment of a standard. Conformity to SIPs is only required for activities within nonattainment areas for non-transportation related sources if emissions are above de minimis levels and regionally significant. Any activity that represents 10 percent, or more, of the emission inventory for that pollutant in the non-attainment or maintenance area is regionally significant. Examples of actions that may require a conformity determination include road paving projects, ski area development, or mining. Activities such as prescribed fire, that are included in a conforming land management plan, are exempt from conformity requirements. Please note that conformity determinations must be made in accordance with applicable EPA regulations, are typically done before a project is approved, and are part of the NEPA process.

The FLM should define the process to be used in conformity determinations and perform the conformity analysis before

a project is implemented. A conformity analysis typically includes emission calculations, public participation, mitigation measures/implementation schedules, and reporting methods. The Pacific Southwest Region of the USFS has published a *Conformity Handbook for FLMs* to assist in conformity compliance. In an approved Plan of Operation, FLMs can require monitoring. For example, in the case of Carlota Mine, located on National Forest land in Arizona, the USFS requested additional mitigation measures to protect AQRVs in the Superstition Wilderness.

Transportation projects in FLM areas classified as nonattainment are subject to a more complicated transportation conformity process. Consultation with State and local air quality and transportation agencies will be required to comply with applicable regulations.

3. Subgroup Reports: Technical Analyses and Recommendations

3.1. Subgroup Objectives and Tasks

Subgroups were formed to address the four key issues relevant to AQRV identification and evaluation issues: policy (and procedures), visibility, ozone, and deposition. Each of these subgroups reviewed the commonalities among the FLMs then addressed the tasks assigned to them by FLAG. One of their first tasks was to differentiate between Phase I tasks, those which could be resolved in the short term without significant additional resources, and Phase II issues, those that would require a longer period or greater effort.

Subgroups were asked to reach common ground among the FLMs on the issues. The intent was to develop, to the extent possible, consistent policies, processes, and terminology that could be used when identifying AQRVs and evaluating impacts on AQRVs. This involves recommending consistent approaches for identifying air pollution effects on AQRVs, for determining adverse impacts, and for attributing adverse impacts to specific pollution sources. In addition, the FLMs consider that AQRV protection from visibility, ozone, and deposition impacts are equally important. However, we also recognize that given the current state of the science, attributing adverse impacts to specific sources are easier to document for visibility than for deposition and ozone, and easier for deposition than ozone.

The individual subgroup reports document the common policies, procedures, and definitions identified or developed during Phase I activities. The Visibility, Ozone, and Deposition subgroup reports are included below. The FLAG Policy Subgroup Report was used as the basis for much of the rest of this *FLAG Phase I Report*, including much of section 1 'Background' and section 2 'Federal Land Managers' Approach to AQRV Protection'.

3.2. Initial Screening Criteria (New)

Experience with the FLAG 2000 recommendations in dealing with many new source review applications led the Agencies to believe that an initial screen that would exempt a source from AQRV impact review based on its annual emissions and distance from a Class I area may be appropriate in most situations. As part of its Regional Haze Regulation, the EPA has introduced a screening criteria in its BART guidelines based on a source's annual emission strength and distance from a Class I area. The EPA stated that it would be reasonable to conclude that the following sources would not be considered to cause or contribute to visibility impairment:



Acadia National Park, Maine.
Credit: National Park Service

- those located more than 50 km from any Class I area that emit less than 500 tons per year of NO_x or SO_2 (or combined NO_x and SO_2), and
- those located more than 100 km from any Class I area that emit less than 1,000 tons per year of NO_x or SO_2 (or combined NO_x and SO_2).

In both cases, the annual emissions over distance factor equates to 10.

The Agencies have concluded that a similar approach has merit with respect to new source impacts at Class I areas, for air pollution sources with relatively steady emissions throughout each year. However, the Agencies are modifying the size criteria to also include Particulate Matter less than 10 microns in size (PM_{10}) and sulfuric acid mist (H_2SO_4) emissions because those pollutants also impair visibility and contribute to other resource impacts. In addition, rather than the two-step BART test, the Agencies are using a fixed Q/D factor of 10 as a screening criteria for sources locating/located greater than 50 km from a Class I area. Furthermore, the Agencies are expanding the screening criteria to include all AQRVs, not just visibility. Therefore, the Agencies will consider a source locating greater than 50 km from a Class I area to have negligible impacts with respect to Class I AQRVs if its total SO_2, NO_x, PM_{10}, and H_2SO_4 annual emissions (in tons per year, based on 24-hour maximum allowable emissions), divided by the distance (in km) from the Class I

area (Q/D) is 10 or less. The Agencies would not request any further Class I AQRV impact analyses from such sources.

In cases where a source's operations which generate visibility-affecting emissions are limited to time periods shorter than a year, the short-term potential to impact visibility may not be adequately expressed by the Q/D concept. For example, a source that is operated either seasonally or intermittently, and has zero emissions for substantial portions of a year, would have a total annual emission rate that under-represents its potential emission strength over a shorter time frame, such as a day or week. Because visibility is an air quality related value that is sensitive to immediate and short-term conditions, in order to apply the Q/D≤10 screening tool, these types of sources need to first adjust the tons-per-year emissions to reflect what the emissions would be if the source operated year-round. For instance, if operations are restricted to 3,000 hours per year, then the annual steady-state-equivalent emission rate (Q) is found by multiplying the permitted total tons per year for SO_2, NO_x, PM_{10} , and H_2SO_4 by the ratio of hours: 8,760 hours per year/3,000 hours operation.[5] Then, using this annual equivalent Q in the Q/D test, the Agencies will consider a source locating greater than 50 km and showing that its ratio of annual equivalent Q (tons per year) divided by distance from the Class I area (km) of 10 or less, as having negligible impacts with respect to Class I visibility impacts, and would not request any further Class I visibility impact analyses from such sources.

3.3. Visibility

3.3.1. Introduction (Revised)

This chapter describes methods for analyzing the impacts on visibility from new or modified air pollution sources. This includes sources that fall under the purview of the Prevention of Significant Deterioration (PSD) regulations and sources that are being analyzed for Environmental Assessments and/or Environmental Impact Statements under the National Environmental Policy Act (NEPA). The basis for some of the decisions outlined in this chapter is Section 169A of the Clean Air Act. The opening statement of this section states: "Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from man made air pollution." Under the regulations promulgated for visibility protection (40 CFR §51.301 (x)) visibility impairment is defined as "…any humanly perceptible change in visibility (visual range, contrast, coloration) from that which would have existed under natural conditions." The remainder of this chapter describes methods that allow for new source growth to be analyzed against the constraint of preventing visibility impairment as defined in 40 CFR §51.301 (x), that is, new source growth should not allow any humanly perceptible change in visibility as compared against natural conditions.

Visibility Impairment

Before proceeding with the discussion, it is useful to identify the ways that visibility impairment can manifest itself. First, the pollutant loading of a section of the atmosphere can become visible, by the contrast or color difference between a layer or plume and a viewed background, such as a landscape feature or the sky. The second way that visibility is impaired is a general alteration in the appearance of landscape features or the sky, changing the color or the contrast between landscape features or causing features of a view to disappear. The first phenomenon is commonly referred to as plume impairment, whereas the second phenomenon is sometimes referred to as uniform haze impairment. As plumes are transported within a stable atmospheric layer, they may become a layered haze. As plumes and other more diffuse emission sources are transported and become well mixed in the atmosphere, they may develop into a uniform haze.

Visibility Parameters (Revised)

The analysis methods for new source growth, described in this chapter, deal with the visibility effects of discrete plumes and the aggregation of discrete plumes into a uniform haze. The difference in these phenomena, as treated in this chapter, is whether the visibility effect is primarily seen as a section of the atmosphere which exhibits a change in contrast or color as compared with a viewed background, or whether the effect is due to an alteration of the appearance of the background features themselves. For the first situation, the contrast (C) and color difference index (ΔE) of the plume and the viewing background are calculated. For the second situation, the change in atmospheric light extinction (Δb_{ext}), relative to natural conditions, is calculated. The light extinction is inversely proportional to "visual range." An approximation for which situation applies is the distance from the point of emission. (Distance serves as an indicator of where steady state conditions may apply.) The visibility impairment from sources within 50 kilometers of a view is usually calculated using contrast and color difference, whereas visibility impairment from sources greater than 50 kilometers from a view, or the aggregation of a number of plumes, regardless of distance, is usually calculated using the change in light extinction. The distance approximation is useful for distinguishing these two phenomena; the terms "near field" and "distant/multi-source" are sometimes used in the remainder of this document to make this distinction.

5. Or, an intermittent hourly emission limit could be annualized by multiplying by 8,760 hours per year/2,000 lb/ton (= 4.38).

3.3.2. Recommendations for Evaluating Visibility Impacts (Revised)

There are two fundamentally different approaches one could adopt to determine visibility impairment. One is a technically rigorous, complex, and situation-specific method, while the other is a more generalized approach. The more rigorous approach requires determination of particle concentrations and size distributions, calculation of particle growth dynamics, and application of elaborate physics (e.g., Mie Theory) to determine the optical characteristics of the aerosol distribution. Sophisticated radiative transfer models are then applied, using aerosol optical characteristics, lighting and scene characteristics, and spatial distribution of the pollutants to calculate the path and wavelength of image-forming and non-image-forming light that reaches a specific observer from all points in the scene being viewed.

While such a detailed analysis may be useful for assessing specific cases, it is usually impractical for situations in which visibility could be experienced in a nearly infinite variety of circumstances. Practical limitations frequently dictate that it is more reasonable to use a generalized approach to determine the change in extinction by using bulk-averaged aerosol-specific extinction efficiencies rather than trying to reproduce the complex optical phenomena that may occur in the atmosphere.

Consequently, as a first-level analysis, FLAG recommends the generalized approach for determining the effects on visibility from a proposed new source's emissions. The procedure is to estimate the atmospheric concentrations of visibility impairing pollutants, apply representative visibility parameters, calculate the change from specified reference levels, and compare this change with prescribed threshold values. The more detailed analysis described above may be appropriate as a refined analysis in the event the source fails the first-level analysis.

FLAG is using EPA's estimates of natural visibility conditions under its Regional Haze Rule as reference levels for Class I visibility analyses. Comparison with natural conditions will help ensure that those conditions will not be impaired in keeping with Section 169A of the CAA. Because of the different requirements of the two modeling approaches discussed below, natural conditions should be expressed using two different metrics:

- Standard visual range (visual range adjusted to a Rayleigh condition of 10 Mm^{-1}), for near field modeling. Present EPA guideline visibility models traditionally accept visibility conditions expressed in these terms.
- Extinction, for distant/multi-source modeling. Visibility conditions should be expressed in terms of the averaged extinction efficiencies of the individual atmospheric constituents that comprise the total extinction. The relative humidity effects of the hygroscopic particles should be accounted for when the change in extinction is calculated.

Information needed to calculate the above indices for all 156 Class I areas for which visibility is an important attribute is provided in Tables 5 through 10 at the end of this chapter. If estimates are needed for Class II areas, the FLM can provide them.

3.3.3. Air Quality Models and Visibility Assessment Procedures (Revised)

The modeling discussion will be divided into two parts to address the very different requirements for 1) near field modeling where plumes or layers are compared against a viewing background, and 2) distant/multi-source modeling for plumes and aggregations of plumes that affect the general appearance of a scene. Note that both of the above analyses might apply depending on the source's proximity to all portions of the Class I area or multiple Class I areas.

FLAG 2000 provided information in the form of recommendations, specific processes, and interpretations of results for assessing visibility impacts of sources affecting Class I areas (although some of this information is generally applicable to Class II areas, as well). The information separately addressed assessments for sources proposing to locate relatively near (within 50 km) and at farther distances (greater than 50 km) from these areas. It also recommended impairment thresholds and identified the conditions for which cumulative analyses could be warranted. This revision (FLAG 2010) updates the Distant/Multi-source analysis discussed in FLAG 2000, and clarifies the recommendations regarding the near-field (within 50 km)/steady-state analysis.

Near Field Analysis Technique for Analyzing Plumes or Layers Viewed Against a Background (Revised)

The Model (Near Field – Steady State Conditions Applicable) (Revised)

EPA has recommended a methodology to assess impacts due to coherent plumes. A guideline for when these steady state conditions apply is the distance from the source to the view of concern. This technique is usually applied for sources locating within 50 km of a Class I area. Applicants should first model their potential plume impacts using the screening model, VISCREEN (EPA 1992a), or, if the next level of analysis is called for, PLUVUE II (EPA 1992b and 1996a). Both of these models use steady-state, gaussian-based plume dispersion techniques to calculate one-hour concentrations within an elevated plume. These two models calculate the change in the color difference index (ΔE) and contrast between the plume and the viewing background. Values of ΔE and plume contrast are based on the concentrations of fine primary particulates (including sulfates), nitrogen dioxide (NO_2), and the geometry of the observer, target, plume, and the position of the sun. PLUVUE II also allows

consideration of the effects of secondarily formed sulfates. Plume contrast results from an increase or decrease in light transmitted from the viewing background through the plume to the observer. The specifics of the emission scenarios and plume/observer geometries for modeling should be selected in consultation with the appropriate Agency representatives. At the present time there is no recommended procedure for conducting analyses of multiple sources with these modeling tools, so multiple coherent plumes should be treated individually, or combined into a representative single source if appropriate. Alternatively, the techniques outlined in the Distant/Multi-Source section below may be used on a case-by-case basis.

The Recommended Procedures (Near Field – Steady State Conditions) (Revised)

Until better modeling tools are available, FLAG recommends using the present EPA techniques for plume visual impact screening analyses (EPA 1992c). However, unlike those procedures, which suggest the use of current average annual visibility conditions, FLAG recommends that for Class I areas the visual range corresponding to natural conditions be used to generate the hourly estimates of ΔE and plume contrast. FLAG recommends this change in order for the analysis technique to be consistent with the national visibility goal. For plume analyses, FLAG recommends using the monthly average natural visual range conditions provided for each area in Table 10.

If a screening analysis of a new or modified source can demonstrate that its emissions will not cause a plume with any hourly estimates of ΔE greater than or equal to 2.0, or the absolute value of the contrast values ($|C|$) greater than or equal to 0.05, the FLM is likely not to object to the issuance of the PSD permit based on near field visibility impacts and no further near field visibility analyses will be requested. More refined analyses (i.e., PLUVUE II) would be undertaken if the above conditions are not met and would be compared against lower levels of concern. For PLUVUE II analyses, the FLM would likely not object if $\Delta E < 1.0$ and $|C| < 0.02$.

All analysis for Class I visibility impacts should include all visibility impairing emissions. This means that even if a facility is only considered a significant emitter of one pollutant, all pollutants that may contribute to impairment should be modeled together. Furthermore, since visibility is an instantaneous value, short-term (24-hour) maximum allowable emissions should be used.

- Level-1 Near Field Screening. Conducting a complete refined plume blight analysis can become rather complex, so three levels of evaluation are available to an applicant. The first, Level-1 screening, is the simplest and most conservative method. As described in the EPA's Workbook for Estimating Visibility Impairment (EPA-450/4-80-031):

  > Level-1 Screening: Level-1 screening is designed to provide a conservative estimate of plume visual impacts (i.e., impacts that would be larger than those calculated with more realistic input and modeling assumptions). This conservatism is achieved by the use within the screening model VISCREEN of worst-case meteorological conditions: extremely stable (F) atmospheric condition, coupled with a very low wind speed (1 m/s) persisting for 12 hours, with a wind that would transport the plume directly adjacent to the observer (as shown schematically in Figure 7).

  Since little project specific information is used for a Level-1 screening analysis, documentation requirements are minimal. Basic information of emissions, meteorological parameters, and model results should be provided. Applicants are encouraged to supply electronic copies of all files necessary to reproduce the results. If an application shows estimated impact values within the thresholds, it is unlikely that additional evaluation will be necessary.

- Level-2 Near Field Screening. If Level-2 screening is necessary, more project specific information is now incorporated. Actual meteorology from the area and emission characteristics of the facility are used. Again, as described in the EPA's Workbook for Estimating Visibility Impairment:

  > Level-2 Screening: As shown in Figure 1, Level-2 plume visual impact screening is done if the Level-1 results exceed the screening criteria. The objective of Level-2 screening is identical to that of Level-1—the estimation of worst-day plume visual impacts—but in Level-2 screening more realistic (less conservative) input, representative of the given source and the Class I area, is provided. This situation-specific input may include particle size distributions for plume and background that are different from those used in the default Level-1 analysis. Median background visual range based on on-site measurements rather than the map shown in Figure 9 might be used. However, the most important potential difference in input between Level-1 and Level-2 analysis centers on meteorology and plume transport and dispersion patterns. While the Level-1 analysis assumes F stability, a 1 m/s wind speed, and a wind direction that would carry plume material very close to the observer, in the Level-2 analysis, meteorological data and topography representative of the source area and Class I area may suggest that worst-case plume dispersion conditions are different.

  It is important to note that the Agencies have maintained the recommendation that all applicants compare

estimated modeled impacts from a facility against natural conditions. This is true for all analysis levels. The use of five years of site-representative meteorology and facility-specific emission characteristics is what makes this analysis different.

As a result of the increased project-specific information, documentation also should include summaries and/or tables describing the additional data sets and evaluation steps taken to conduct the analysis.

Once again, meeting screening thresholds means that it is likely that the Agencies' Class I air quality modeling procedures will have been satisfied.

- Level-3 Near Field Refined Analysis. A Level-3 analysis is the final assessment. An applicant can conduct a full refined analysis demonstrating estimates of frequency, magnitude, and spatial extent of a proposed project's visibility impacts. The EPA's Workbook for Estimating Visibility Impairment says:

  > Level-3 Analysis: In Level-3 analysis, the objective is broadened from conservative analysis of worst-case conditions to a realistic analysis of all conditions that would be expected to occur in a typical year in the region that includes both the emission source and the observer. Level-3 analysis is no longer considered screening because it is a comprehensive analysis of the magnitude and frequency of occurrence of plume visual impacts as observed at a sensitive Class I area vista.
  >
  > It is important to determine the frequency of occurrence of visual impact because the adversity or significance of impact is dependent on how frequently an impact of a given magnitude occurs. For example, if a plume is perceptible from a Class I area a third of the time, the impact would be considered much more significant than if it were perceptible only one day per year. The assessment of frequency of occurrence of impact should be an integral part of Level-3 visual impact analysis.

  As mentioned above, the threshold values for this analysis step changed. For this step, EPA's PLUVUE II model is currently recommended. One main difference with PLUVUE II is its inability to evaluate more than one hour of impact per run. Because it is customary to evaluate five years of site-specific meteorology, it can become an extensive process. Applicants may want to develop and utilize tools to group hourly meteorological and post processing scenarios. The analysis identifies specific locations for plume/observer relationships. These observation points should be established within each potentially impacted Class I area. With each observer, potential impacts are calculated for all possible views. As with the meteorology, PLUVUE II is only able to assess one observer location per model run. Specific information on setup methods can be found in EPA's Workbook for Estimating Visibility Impairment and PLUVUE II manual.

  Substantial documentation is needed for this more refined analysis. The discussion should summarize data sources, processing methods, and modeling utilities used, and information regarding all assumptions or consolidation criteria. In short, sufficient information and electronic files should be provided to the Agencies that will allow reviewers to reproduce the results. Due to the complexity of this refined analysis, the Agencies suggest that consultation occur between the applicant and the Agencies before working on the impact analysis begins. Furthermore, selection of model parameters and input data should be documented in a written protocol and agreed upon by the affected Agencies in advance of any modeling being conducted.

If the estimated plume parameters exceed the aforementioned values, the FLM would rely on a case-by-case effects-based test (NPS 1993), taking into account magnitude, frequency, duration, and other factors, to decide whether to make an adverse impact determination.

Distant/Multi-Source Techniques for Analyzing Whether a Plume or an Aggregation of Plumes Alters the General Appearance of a Scene (Revised)

This analysis is generally more complex than the near field, coherent plume modeling analyses and the guidance from EPA is less definitive, though it is evolving. The modeling system should include the capability to assess single and multiple sources in a temporally and spatially varying meteorological domain, accommodate modeling domains measuring hundreds of kilometers, include rough and complex terrain, provide pollutant concentration estimates for averaging times from one-hour to annual, and address inert and secondarily formed pollutants and dry and wet deposition. In the early 1990s the FLMs and the EPA recognized the need for a consistent, technically credible technique to estimate contributions to air quality of multiple new sources locating more than 50 km from Class I areas. Towards that end, on April 15, 2003, the EPA promulgated revisions to Appendix W of 40 C.F.R. §51 (*Guideline on Air Quality Models*). The EPA revised the Guideline to adopt the CALPUFF model as the preferred long-range transport model for inclusion in Appendix A of that document. This technique is usually applied when sources are located more than 50 kilometers from portions of a Class I area, when an aggregation of plumes may impact an area, or when the assumptions inherent in steady state visibility models do not apply.

The first-level analysis procedures discussed in this revision differ from FLAG 2000 in several discrete areas, but

generally remain the same. The primary differences are in the areas of the reference natural conditions that are used in the comparisons for thresholds of concern and using the average monthly relative humidity adjustment factors rather than the hour-by-hour factors identified in FLAG 2000. CALPUFF is still the preferred first-level air quality model for calculating pollutant concentrations, however, using "CALPUFF Lite" with single station meteorology is no longer recommended. We wish to emphasize that the first-level procedures defined herein are to be taken as a whole; any deviations from these procedures or ostensible refinements compromise the integrity of the analysis, and may warrant an hourly analysis for all hours in the analysis. Furthermore, the metric used for the first-level analysis (relative change in light extinction) is not necessarily the appropriate metric for a refined analysis. The procedures and metrics for refined analyses will need to be agreed upon by the affected Agencies.

The initial step in conducting the first-level analysis is to run CALPUFF using a minimum of three years of mesoscale meteorological model output, and preferably five years, consistent with current EPA guidance. Selection of model parameters and input data should be documented in a written protocol and agreed upon by the affected Agencies in advance of any modeling being conducted. Please note emissions input considerations and model receptor grid data are discussed below. The indices for comparison with the Agencies' levels of concern are calculated in CALPOST. The remainder of this discussion is focused on CALPOST.

After CALPUFF is run, CALPOST is used to evaluate whether the proposed source or modification will be below the Agencies' threshold for concern (i.e., 5% change in light extinction). The CALPOST parameter MVISBK is set to eight (8), sub-mode five (M8_MODE = 5), and the background hygroscopic and non-hygroscopic aerosol levels are derived from the annual average natural conditions provided in Table 6. The monthly relative humidity adjustment factors for the Class I area are input to the RHFAC array (Tables 7-9) in CALPOST. The 98th percentile test applies to the number of days that any model receptor in the Class I area exceeds the threshold. The visibility threshold for concern is not exceeded if the 98th percentile change in light extinction is less than 5% for each year modeled, when compared to the annual average natural condition value for that Class I area.

If this analysis indicates that the 98th percentile values for change in light extinction are equal to or greater than 5% for any year, then the Agencies will further scrutinize the applicant's proposal. The Agencies will consider the full range of factors discussed below (in the "Expansion of Discussion of Process for Adverse Impact Determination" chapter) and any refined analyses provided by the applicant before making a recommendation to the FLM regarding potential adverse impacts. As noted above, these refined analyses should account for the relevant physicochemical processes that produce visibility impairing pollutants and accurately treat the relevant radiative transfer properties affecting visibility. This will likely entail using different meteorological and air quality models capable of producing hourly concentrations, or less, and using a three dimensional radiative transfer model (see refined analysis discussion below).

For consistency with implementation of BART or the regional haze rule to specific Class I areas, the FLM or permitting authority may recommend use of the 20% best natural background values provided in Table 5 in lieu of annual averages on a case-by-case basis.

Background Information on Thresholds

In its BART guidelines, EPA indicated that for regional haze, a source whose 98th percentile value of the haze index is greater than 0.5 deciview (dv) (approximately a 5% change in light extinction) is considered to contribute to regional haze visibility impairment. Similarly, a source that exceeds 1.0 dv (approximately a 10% change in light extinction) causes visibility impairment. The 0.5 dv and 1.0 dv thresholds are similar to what the Agencies used in FLAG 2000. Therefore, for consistency between visibility protection programs and to address similar concerns, the Agencies will also use the 98th percentile value as a threshold in the first-level visibility analyses for new source impacts.

In its 2005 BART guidelines, the EPA also concluded that by using the 98th percentile of CALPUFF modeled impacts the sources that contribute 0.5 deciview to regional haze visibility impairment in a Class I area would effectively be captured, while minimizing the likelihood that the highest modeled visibility impacts might be caused by conservative assumptions in the model. Similarly, using the monthly average relative humidity adjustment factors, rather than the hour-by-hour factors, reduces some of the higher (e.g., weather –related) values seen in FLAG 2000.

Using the 98th percentile of modeled visibility values to compare to the 5% change in extinction threshold would exclude roughly seven days per year from consideration for each Class I area. However, consistent with the BART guidelines, the 98th percentile test applies to the number of days that any model receptor in the Class I area exceeds the threshold. Also, this test is limited to haze-like, first-level analyses. Therefore, all applicable sources locating within 50 km of a Class I area would still need to assess coherent plume impacts in accordance with the procedure described above. Furthermore, applicable sources would need to assess sulfur and nitrogen deposition impacts at the Class I area.

Natural Conditions

FLAG 2000 discussed assessing the change in visibility due to a proposed new source relative to annual average natural conditions. Therefore, it is important to define

natural conditions for each Class I area. At the time of FLAG 2000, the Agencies acknowledged that the EPA was working on defining natural conditions in support of their visibility regulations. In the absence of more specific data, the FLMs at that time adopted the appropriate aerosol concentrations developed by the National Acid Precipitation Assessment Program (NAPAP) as estimates of natural conditions for each Class I area. The EPA has since published natural condition estimates for each Class I area. The natural condition values provided in FLAG 2000 and those developed by the EPA are based on similar underlying assumptions; consequently, the estimates are similar. Regardless, the EPA estimates should be used by applicants in future visibility impact assessments. Please note that Tables 5 and 6 contain estimates for the 20% best natural visibility and annual average natural visibility conditions for each Class I area, respectively.

Relative Humidity Adjustment Factor

FLAG 2000 discussed the importance of the relative humidity adjustment factor (f(RH)) when calculating the sulfate and nitrate components of the visibility extinction coefficient. These aerosols are hygroscopic and the addition of water enhances their scattering efficiencies. FLAG 2000 recommended using hour-by-hour f(RH) for the analysis. The EPA, in its 2005 BART guidelines, concluded that by using a monthly average f(RH) the likelihood that the highest modeled visibility impacts were caused by short-term and geographically different meteorological phenomena (e.g., weather events) would be minimized. The Agencies agree with the EPA that using the monthly f(RH) effectively neutralizes short-term weather events and are adopting a similar approach for Class I visibility impact analyses for new sources. Therefore, new sources performing Class I visibility analyses should use monthly average f(RH) values developed by EPA for large hygroscopic particles (Table 7), small hygroscopic particles (Table 8), and sea salt (Table 9), rather than the hourly values discussed in FLAG 2000.

Emissions Input

There are two other aspects of the visibility impact analysis that the Agencies would like to clarify at this time: (1) emissions input, and (2) the model receptor grid. Regarding the emission inputs, because applicants are assessing a 24-hour average regional haze visibility impact, it is important that they model a corresponding maximum allowable 24-hour mass emission rate, as opposed to monthly or annual average emissions. Using a 30 day average emission rate as input to the visibility modeling analyses does not restrict the facility from emitting pollution at a higher rate for shorter time periods (e.g., 24-hour average). A 30 day average emission rate smooths out days with high emissions, and therefore, would underestimate the predicted 24-hour visibility impacts. Because the emission rates and the corresponding averaging times influence the outcome of the analyses, it is critical that appropriate emissions are matched to the averaging time being assessed, and that these emission rates ultimately are included as enforceable permit conditions. This approach is consistent with the *Guideline on Air Quality Models* (Appendix W of 40 C.F.R. §51) and the EPA BART guidelines. Furthermore, if an applicant chooses to conduct any refined analyses, where visibility impairment is assessed at no more than an hourly basis, maximum hourly emissions should be analyzed.

Please note that all visibility impairing pollutants should be modeled from all modified or affected emission unit(s), regardless of which pollutants actually triggered NSR. Particulate Matter (PM) should also be speciated into filterable PM (coarse, fine, elemental carbon) and Condensable PM (organic carbon and sulfates) based on the best available information. Particulate speciation data for several source types can be found on the NPS Air Resources Division's web site at:

- http://www.nature.nps.gov/air/permits/ect/index.cfm

Applicants should calculate the 24-hour average net emission increase for each pollutant from modified facilities as the maximum allowable 24-hour average minus the actual hourly rate averaged over the past two years (annual emissions over past two years/hours of operation over last two years).[6]

Model Receptor Grid

Since FLAG 2000 was published, the NPS Air Resources Division has developed a database of modeling receptors for all of the Class I areas in the contiguous United States. A file conversion program to convert the data from latitude/longitude to other common mapping coordinates (currently Lambert Conformal and Universal Transverse Mercator (UTM)) has also been developed. Alaska and Hawaii are not yet complete, but will be included in the data sets when they are available.

Permit applicants can download the Class I Receptor Data files, as well as the Conversion program, from the link below. For modeling consistency, the Agencies ask that permit applicants use the uniform receptor grids provided. Also available are the Class I boundary shape files that were used to create the receptor data files.

- http://www.nature.nps.gov/air/Maps/Receptors/index.cfm

Receptor grids for FLM Class II areas should be dense enough to determine Class II increment consumption and

6. Note that this is different from the emission change calculation used for short-term increment, which is calculated as the maximum allowable 24-hour average minus the highest occurrence over the past two years.

to perform any required "secondary impacts" (i.e., soils, vegetation and visibility) analyses.

Refined Analysis

It is important to reiterate that the FLAG distant/multi-source visibility analysis is only a first-level screening technique, primarily designed to identify those sources that are unlikely to significantly affect visibility and warrant no further analysis, and those that may adversely impact visibility and warrant further scrutiny. Visibility is experienced instantaneously, not on a 24-hour average basis. The 24-hour average visibility calculation in FLAG is acceptable because of a number of simplifying assumptions in the prescribed technique. Accepting certain EPA BART guideline procedures as an update to the FLAG techniques does not alter the first-level nature of the procedure. Modifying those simplifying assumptions negates the acceptability of using a 24-hour average. Consequently, any applicant whose visibility analysis deviates from the recommended FLAG screening procedures warrants performing an hour-by-hour analysis.

Deviations from the first-level screening procedure should lead to refinements in the modeling and visibility analyses, not arbitrary adjustments to the prescribed first-level technique. This is especially important in dealing with weather-related events. The Agencies believe that by paralleling the BART guideline procedures they have adequately taken into account the effects of meteorological extremes, and model uncertainty. Therefore, given the Agencies' desire to balance the positive and negative biases of the FLAG screening methodology, any modifications to the screening technique invalidate the Level 1 model results. Consequently, the Agencies do not expect permit applicants that exceed the visibility effects thresholds to scrutinize the data and attempt to disregard specific impact days due to weather. Under those circumstances, the permit applicant can accept the modeling results at face value, and then the FLM will decide whether or not those impacts are adverse. Alternatively, the applicant could conduct an hour-by-hour analysis (as opposed to using a 24-hour average) by performing a refined analysis using a more sophisticated approach that requires determining particle concentrations and size distributions, calculation of particle growth dynamics, and application of Mie Theory to determine the optical characteristics of the aerosol distribution. Sophisticated radiative transfer models can then be applied, using aerosol optical characteristics, lighting and scene characteristics, and spatial distribution of the pollutants to calculate the path and wavelength of image-forming and non-image-forming light that reaches a specific observer from all points in the scene being viewed. The concept of this more refined approach is discussed in FLAG 2000, and one possible approach is included in "*Proposed FLAG Level II and III Visibility Assessment*" (Schichtel et al. 2006). However, if this situation arises, permit applicants are encouraged to consult with the Agencies and discuss the specifics of this refined analysis.

3.3.4. Summary (Revised)

FLAG provides recommendations, specific procedures, and interpretation of results for assessing visibility impacts of new or modified sources on Class I area resources. Although FLMs only have a formal role in the permitting process for applications that affect Class I areas, this information can be used for Class II areas as well. FLAG addresses assessments for sources proposed for locations near (generally within 50 km) and at large distances (greater than 50 km) from these areas. The key components of the recommendations are highlighted below.

In general, FLAG recommends that an applicant:

- Apply the Q/D test (see section 3.2, 'Initial Screening Criteria') for proposed sources greater than 50 km from a Class I area to determine whether or not any further visibility analysis is necessary.
- Consult with the appropriate regulatory agency and with the FLM for the affected Class I area(s) or other affected area for confirmation of preferred visibility analysis procedures.
- Obtain FLM recommendation for the specified reference levels (estimate of natural conditions) and, if applicable, FLM recommended plume/observer geometries and model receptor locations.
- Apply the applicable EPA Guideline, steady-state models for regions within the Class I area that are affected by plumes or layers that are viewed against a background (generally within 50 km of the source).
    - Calculate hourly estimates of changes in visibility, as characterized by the change in the color difference index (ΔE) and plume contrast (C), with respect to natural conditions, and compare these estimates with the thresholds given in section 3.3.3.
- For regions of the Class I area where visibility impairment from the source would cause a general alteration of the appearance of the scene (generally 50 km or more away from the source or from the interaction of the emissions from multiple sources), apply a non-steady-state air quality model with chemical transformation capabilities (refer to EPA guidance documents), which yields ambient concentrations of visibility-impairing pollutants. At each Class I receptor:
    - Calculate the change in extinction due to the source being analyzed, compare these changes with the reference conditions, and then compare these results with the thresholds given in section 3.3.3.
    - Utilize estimates of annual average natural visibility conditions for each Class I area as presented in Table 6, unless otherwise recommended by the

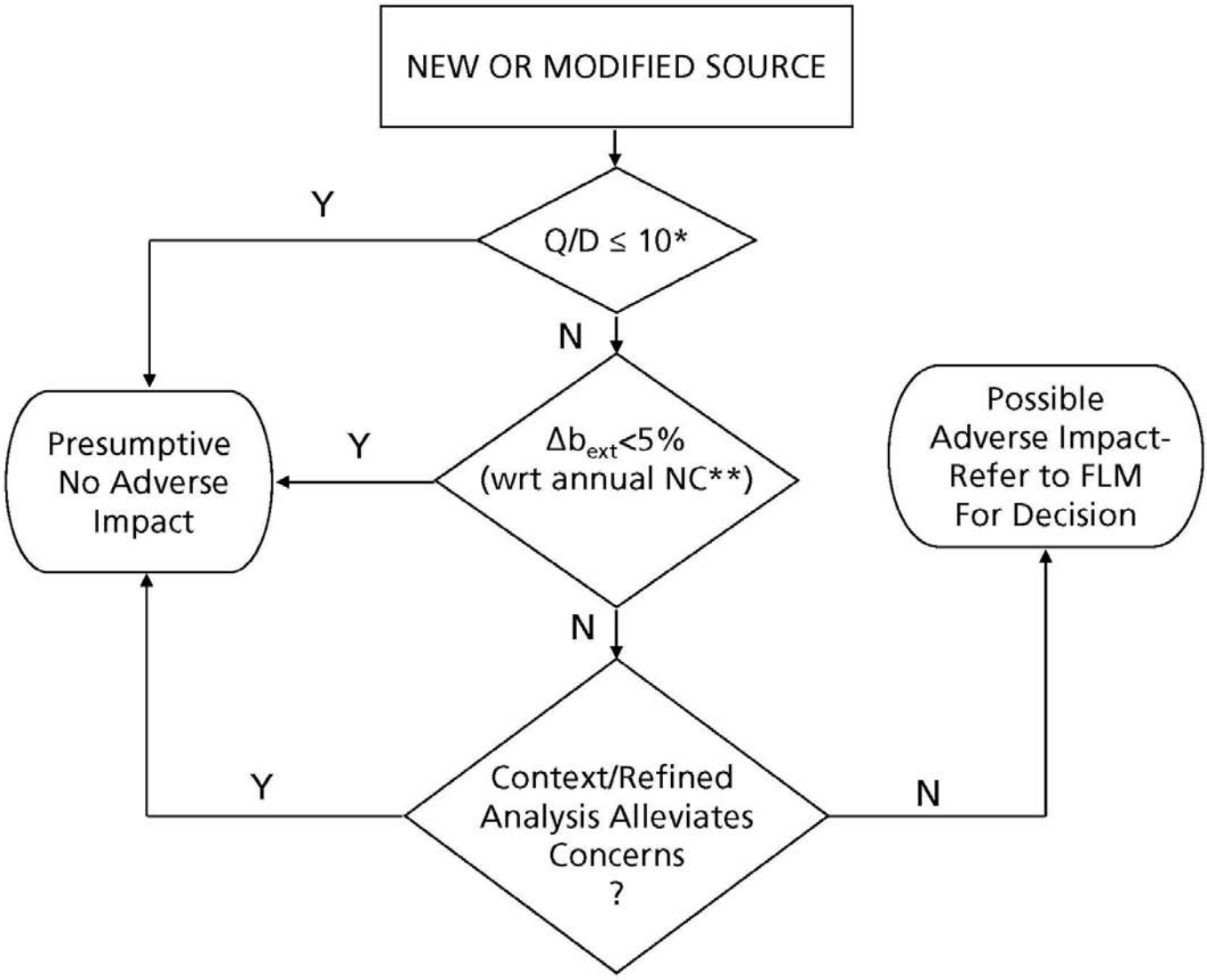


Figure 4. Procedure for Visibility Assessment for Distant/Multi-Source Applications (Revised)
*Q/D test only applies to sources located greater that 50 km from a Class I area.
**Difference Change in the 98th percentile with respect to (wrt) the annual average Natural Condition (NC). Applicant should use the 20th percentile best natural condition background if recommended by the FLM or permitting authority.

FLM or permitting authority. Alternative estimates of visibility conditions are provided in Table 5 for consistency with State agencies that elected to use 20% best visibility for regional haze or BART implementations.

- If first-level modeling results are above levels of concern, continue to consult with the Agencies to discuss other considerations (e.g., possible impact mitigation, more refined analyses).

This review process for distant/multi-source applications is portrayed schematically in Figure 4.

3.3.5. Natural Visibility Conditions and Analysis Methods (New)

Both distant/multi-source applications and near-field analyses require an estimate of natural visibility conditions. The effects of visibility impairing emissions from a source are compared to the natural visibility conditions to determine the potential for unacceptable visibility impacts. The methods and data for calculating natural visibility conditions in FLAG are presented in this section. The calculation of visibility metrics under the distant/multi-source application is also described. For the distant/multi-source application, aerosol species components are provided for input to the CALPUFF modeling system, which is the suggested model

for most of these applications. For near-field analyses, visual ranges under natural conditions are provided for input to the VISCREEN and PLUVUE-II models.

Natural visibility conditions

Distant/Multi-source: Natural visibility conditions are affected by the light scattering of air molecules (Rayleigh scattering) and by naturally occurring aerosols. The majority of aerosols, both natural and anthropogenic, that affect light extinction can be categorized as sulfates ($(NH_4)_2SO_4$), nitrates (NH_4NO_3), organic mass (OM), elemental carbon (EC), soil, sea salt, and coarse mass (CM). The light scattering efficiency of aerosols is affected by the size of the aerosol relative to the wavelength of light. Sulfates, nitrates, and sea salt are all hygroscopic, which affects their size and their light scattering efficiency as they acquire or shed water molecules. The relationship between the aerosol components and light extinction is shown through the equations in Figure 5. The hygroscopic effects are accounted for through the relative humidity adjustment factors (f(RH)) terms in the equations in Figure 5. The aerosol concentrations and monthly relative humidity adjustment factors for calculating natural visibility conditions are found in Tables 5 through 10.

Table 2. Section of Table 6 Used for Step 1 Calculations of the Alpine Lakes Wilderness Example

Class I Area	$(NH_4)_2SO_4$ µg/m³	NH_4NO_3 µg/m³	OM µg/m³	EC µg/m³	Soil µg/m³	CM µg/m³	Sea Salt µg/m³	Rayleigh Mm^{-1}
Acadia NP	0.23	0.10	1.67	0.02	0.24	2.14	0.14	12
Agua Tibia Wilderness	0.12	0.10	0.60	0.02	0.50	3.00	0.14	11
Alpine Lakes Wilderness	0.12	0.10	0.60	0.02	0.23	1.30	0.06	11
…	…	…	…	…	…	…	…	…

The aerosol concentrations for the 20% best natural conditions are found in Table 5 and the annual average natural concentrations are found in Table 6.

Near-field: The near-field visibility analysis is generally performed using either VISCREEN or PLUVUE-II. For calculating the effect of a plume on visibility, a background visibility, expressed as a visual range, must be input to these models. Appropriate average natural conditions, by month and Class I area are listed in Table 10. The values in Table 10 were determined by calculating the month by month light extinction values and calculating the visual range (VR) ($VR=3912/b_{ext}$).

Example Calculation of Natural Conditions and Change in Light Extinction

The annual average concentration and the relative humidity adjustment factors ($f_{(L,S,SS)}(RH)$) for the Alpine Lakes Wilderness for January will be used for illustration of the calculations.

1. Look up the Alpine Lakes Wilderness annual average concentration values in Table 6 for sulfate ($(NH_4)_2SO_4$), nitrate (NH_4NO_3), organic mass (OM), Elemental Carbon (EC), soil, coarse mass (CM), sea salt, and Rayleigh scattering.
2. Look up the f(RH) factors for large sulfate/nitrate (table 7), small sulfate/nitrate (table 8), and sea salt (table 9); January in this example.
   a. $f_L(RH) = 3.86$
   b. $f_S(RH) = 5.87$
   c. $f_{SS}(RH) = 5.35$
3. Calculate the large and small sulfate, nitrate, and organic mass, as defined in Figure 5.

Table 3. Step 3 Calculation Results for the Alpine Lakes Wilderness Example

	Total	Large	Small
Sulfate	0.12	0.00072	0.11928
Nitrate	0.10	0.0005	0.0995
Organic Mass	0.60	0.018	0.582

4. Apply to b_{ext} equation in Figure 5:

$$
\begin{aligned}
b_{ext} = \; & 2.2 \times 5.87 \times 0.11928 + 4.8 \times 3.86 \times 0.00072 && \{\text{Sulfate}\} \\
& + 2.4 \times 5.87 \times 0.0995 + 5.1 \times 3.86 \times 0.0005 && \{\text{Nitrate}\} \\
& + 2.8 \times 0.582 + 6.1 \times 0.018 && \{\text{Organic Mass}\} \\
& + 10 \times 0.02 && \{\text{Elemental Carbon}\} \\
& + 1 \times 0.23 && \{\text{Soil}\} \\
& + 0.6 \times 1.30 && \{\text{Coarse Mass}\} \\
& + 1.7 \times 5.35 \times 0.06\} && \{\text{Sea Salt} \\
& + 11 && \{\text{Rayleigh}\} \\
& + 0.33 \times 0 && \{NO_2\} \\
b_{ext} = \; & 17.46\ Mm^{-1}
\end{aligned}
$$

To calculate the change in light extinction from the impacts from an air pollution source, the species concentrations from the source are added to the total species concentrations in steps 3 and 4 above and the new total light extinction is calculated. Therefore, if a source contributed 0.05 µg/m³ of sulfate ($(NH_4)_2SO_4$) and 0.01 µg/m³ of nitrate (NH_4NO_3) at a receptor, the total, large and small sulfate and nitrate values would be:

Table 4. Step 4 Calculation Results for the Alpine Lakes Wilderness Example

	Total	Large	Small
Sulfate	0.17 (0.12+0.05)	0.001445	0.168555
Nitrate	0.11 (0.10+0.01)	0.000605	0.109395

The other concentrations and the relative humidity adjustment factors would remain as in step 4 of the natural condition example. After recalculating the light extinction accounting for the effect of the source ($b_{ext(source+nat\ cond)}$), the new light extinction would be 18.25 Mm^{-1}.

The change in light extinction (Δb_{ext}) would simply be:

$$\Delta b_{ext} = (b_{ext(source+nat\ cond)} - b_{ext(nat\ cond)}) / b_{ext(nat\ cond)} \text{ or:}$$

$$\Delta b_{ext} = (18.25 - 17.46) / 17.46$$

$$\Delta b_{ext} = 0.045\ (4.5\%)$$

The example provided here is to illustrate the process. Usually the concentrations and relative humidity adjustment factors would be extracted from the appropriate tables and input to one of the air quality model post processing programs.

$$
\begin{aligned}
b_{ext} = \quad & 2.2 \times f_S(RH) \times [\text{Small Sulfate}] + 4.8 \times f_L(RH) \times [\text{Large Sulfate}] \\
& + 2.4 \times f_S(RH) \times [\text{Small Nitrate}] + 5.1 \times f_L(RH) \times [\text{Large Nitrate}] \\
& + 2.8 \times [\text{Small Organic Mass}] + 6.1 \times [\text{Large Organic Mass}] \\
& + 10 \times [\text{Elemental Carbon}] \\
& + 1 \times [\text{Fine Soil}] \\
& + 0.6 \times [\text{Coarse Mass}] \\
& + 1.7 \times f_{SS}(RH) \times [\text{Sea Salt}] \\
& + \text{Rayleigh Scattering (Site Specific)} \\
& + 0.33 \times [NO_2\ (\text{ppb})] \quad \{\text{or as: } 0.1755 \times [NO_2\ (\mu g/m^3)]\}
\end{aligned}
$$

Where:

[ ] indicates concentrations in $\mu g/m^3$

$f_S(RH)$ = Relative humidity adjustment factor for small sulfate and nitrate

$f_L(RH)$ = Relative humidity adjustment factor for large sulfate and nitrate

$f_{SS}(RH)$ = Relative humidity adjustment factor for sea salt

For Total Sulfate $< 20\ \mu g/m^3$:

$$[\text{Large Sulfate}] = ([\text{Total Sulfate}] / 20\ \mu g/m^3) \times [\text{Total Sulfate}]$$

For Total Sulfate $\geq 20\ \mu g/m^3$:

$$[\text{Large Sulfate}] = [\text{Total Sulfate}]$$

And:

$$[\text{Small Sulfate}] = [\text{Total Sulfate}] - [\text{Large Sulfate}]$$

To calculate large and small nitrate and organic mass, substitute ({Large, Small, Total} {Nitrate, Organic Mass}) for Sulfate.

Figure 5. IMPROVE Equation for Calculating Light Extinction
http://vista.cira.colostate.edu/improve/Publications/GrayLit/019_RevisedIMPROVEeq/RevisedIMPROVEAlgorithm3.doc

Table 5. 20% Best Natural Conditions – Concentrations and Rayleigh Scattering By Class I Area									
Class I Area	$(NH_4)_2SO_4$ µg/m3	NH_4NO_3 µg/m3	OM µg/m³	EC µg/m³	Soil µg/m³	CM µg/m³	Sea Salt µg/m³	Rayleigh Mm^{-1}	Type
Acadia NP	0.09	0.03	0.68	0.01	0.10	0.94	0.03	12	B20%
Agua Tibia Wilderness	0.03	0.04	0.26	0.01	0.26	1.20	0.04	11	B20%
Alpine Lakes Wilderness	0.04	0.03	0.15	0.01	0.05	0.30	0.02	11	B20%
Anaconda Pintler Wilderness	0.04	0.03	0.12	0.01	0.07	0.31	0.00	10	B20%
Ansel Adams Wilderness	0.02	0.01	0.12	0.01	0.07	0.44	0.01	9	B20%
Arches NP	0.07	0.06	0.23	0.01	0.14	0.89	0.01	9	B20%
Badlands NP	0.05	0.05	0.23	0.01	0.22	0.99	0.00	11	B20%
Bandelier NM	0.07	0.06	0.31	0.01	0.16	0.91	0.00	9	B20%
Bering Sea Wilderness									B20%
Big Bend NP	0.05	0.04	0.24	0.01	0.11	0.80	0.00	10	B20%
Black Canyon of the Gunnison NP	0.06	0.04	0.24	0.01	0.13	0.88	0.00	9	B20%
Bob Marshall Wilderness	0.05	0.04	0.19	0.01	0.08	0.37	0.00	10	B20%
Bosque del Apache Wilderness	0.08	0.06	0.30	0.01	0.15	0.97	0.02	10	B20%
Boundary Waters Canoe Area Wilderness	0.11	0.02	0.50	0.01	0.13	0.86	0.01	11	B20%
Breton Wilderness	0.14	0.05	0.73	0.01	0.27	2.26	0.07	11	B20%
Bridger Wilderness	0.05	0.04	0.14	0.01	0.07	0.33	0.00	9	B20%
Brigantine Wilderness	0.12	0.04	0.86	0.01	0.24	1.73	0.04	12	B20%
Bryce Canyon NP	0.04	0.05	0.18	0.01	0.10	0.60	0.00	9	B20%
Cabinet Mountains Wilderness	0.05	0.05	0.13	0.01	0.09	0.42	0.01	10	B20%
Caney Creek Wilderness	0.07	0.06	0.68	0.01	0.14	1.51	0.02	11	B20%
Canyonlands NP	0.07	0.06	0.23	0.01	0.14	0.89	0.01	9	B20%
Cape Romain Wilderness	0.14	0.06	0.88	0.01	0.24	1.99	0.04	12	B20%
Capitol Reef NP	0.06	0.07	0.26	0.01	0.15	0.79	0.01	9	B20%
Caribou Wilderness	0.03	0.02	0.12	0.01	0.08	0.24	0.01	10	B20%
Carlsbad Caverns NP	0.06	0.05	0.26	0.01	0.12	0.82	0.00	9	B20%
Chassahowitzka Wilderness	0.14	0.08	1.02	0.01	0.28	2.46	0.02	11	B20%
Chiricahua NM	0.06	0.05	0.27	0.01	0.13	0.81	0.00	10	B20%
Chiricahua Wilderness	0.06	0.05	0.27	0.01	0.13	0.81	0.00	10	B20%
Cohutta Wilderness	0.09	0.08	0.69	0.01	0.15	1.06	0.01	11	B20%
Crater Lake NP	0.02	0.02	0.08	0.01	0.07	0.23	0.01	9	B20%
Craters of the Moon NM	0.06	0.05	0.19	0.01	0.12	0.69	0.01	10	B20%
Cucamonga Wilderness	0.03	0.03	0.15	0.01	0.14	0.67	0.01	9	B20%
Denali NP & Pres	0.04	0.02	0.08	0.01	0.05	0.31	0.01	11	B20%
Desolation Wilderness	0.04	0.03	0.15	0.01	0.09	0.51	0.01	9	B20%
Diamond Peak Wilderness	0.02	0.02	0.08	0.01	0.07	0.23	0.01	9	B20%
Dolly Sods Wilderness	0.10	0.05	0.80	0.01	0.17	0.96	0.01	10	B20%
Dome Land Wilderness	0.03	0.02	0.18	0.01	0.08	0.43	0.01	10	B20%
Eagle Cap Wilderness	0.05	0.02	0.17	0.01	0.10	0.50	0.01	10	B20%
Eagles Nest Wilderness	0.04	0.03	0.14	0.01	0.08	0.36	0.00	8	B20%
Emigrant Wilderness	0.03	0.02	0.10	0.00	0.08	0.50	0.01	10	B20%
Everglades NP	0.16	0.07	0.77	0.01	0.16	1.86	0.12	11	B20%
Fitzpatrick Wilderness	0.05	0.04	0.14	0.01	0.07	0.33	0.00	9	B20%
Flat Tops Wilderness	0.04	0.03	0.14	0.01	0.08	0.36	0.00	8	B20%
Galiuro Wilderness	0.06	0.05	0.27	0.01	0.13	0.81	0.00	10	B20%

Table 5. 20% Best Natural Conditions – Concentrations and Rayleigh Scattering By Class I Area									
Class I Area	$(NH_4)_2SO_4$ µg/m3	NH_4NO_3 µg/m3	OM µg/m³	EC µg/m³	Soil µg/m³	CM µg/m³	Sea Salt µg/m³	Rayleigh Mm^{-1}	Type
Gates of the Mountains Wilderness	0.04	0.04	0.13	0.01	0.07	0.49	0.00	9	B20%
Gearhart Mountain Wilderness	0.02	0.02	0.08	0.01	0.07	0.23	0.01	9	B20%
Gila Wilderness	0.06	0.04	0.22	0.01	0.09	0.45	0.00	9	B20%
Glacier NP	0.05	0.03	0.17	0.01	0.11	0.57	0.00	11	B20%
Glacier Peak Wilderness	0.02	0.03	0.09	0.00	0.04	0.28	0.01	11	B20%
Goat Rocks Wilderness	0.02	0.01	0.06	0.00	0.04	0.21	0.01	10	B20%
Grand Canyon NP	0.04	0.03	0.12	0.01	0.10	0.59	0.00	9	B20%
Grand Teton NP	0.06	0.05	0.17	0.01	0.08	0.33	0.00	9	B20%
Great Gulf Wilderness	0.09	0.04	0.56	0.01	0.10	1.05	0.02	11	B20%
Great Sand Dunes NP & Pres	0.06	0.05	0.29	0.01	0.15	0.90	0.00	9	B20%
Great Smoky Mountains NP	0.09	0.06	0.78	0.01	0.16	1.47	0.01	11	B20%
Guadalupe Mountains NP	0.06	0.05	0.26	0.01	0.12	0.82	0.00	9	B20%
Haleakala NP	0.05	0.04	0.24	0.01	0.11	1.59	0.13	10	B20%
Hawaii Volcanoes NP	0.03	0.04	0.27	0.01	0.06	0.64	0.11	10	B20%
Hells Canyon Wilderness	0.06	0.02	0.19	0.01	0.14	0.81	0.01	11	B20%
Hercules-Glades Wilderness	0.09	0.06	0.78	0.01	0.16	1.86	0.02	11	B20%
Hoover Wilderness	0.03	0.02	0.08	0.01	0.06	0.55	0.00	9	B20%
Isle Royale NP	0.10	0.02	0.34	0.01	0.09	0.79	0.01	12	B20%
James River Face Wilderness	0.11	0.06	0.71	0.01	0.20	1.39	0.01	11	B20%
Jarbidge Wilderness	0.05	0.03	0.14	0.01	0.05	0.33	0.00	10	B20%
John Muir Wilderness	0.02	0.01	0.12	0.01	0.07	0.44	0.01	9	B20%
Joshua Tree NP	0.04	0.02	0.20	0.01	0.17	0.94	0.02	10	B20%
Joyce Kilmer-Slickrock Wilderness	0.09	0.06	0.78	0.01	0.16	1.47	0.01	11	B20%
Kaiser Wilderness	0.02	0.01	0.12	0.01	0.07	0.44	0.01	9	B20%
Kalmiopsis Wilderness	0.03	0.02	0.31	0.01	0.05	0.99	0.04	12	B20%
Kings Canyon	0.03	0.03	0.18	0.01	0.08	0.73	0.02	11	B20%
La Garita Wilderness	0.06	0.04	0.24	0.01	0.13	0.88	0.00	9	B20%
Lassen Volcanic NP	0.03	0.02	0.12	0.01	0.08	0.24	0.01	10	B20%
Lava Beds NM	0.03	0.03	0.14	0.01	0.06	0.46	0.00	10	B20%
Linville Gorge Wilderness	0.08	0.06	0.67	0.01	0.14	1.04	0.01	11	B20%
Lostwood Wilderness	0.06	0.04	0.23	0.01	0.22	1.05	0.01	11	B20%
Lye Brook Wilderness	0.05	0.03	0.36	0.01	0.09	0.63	0.01	11	B20%
Mammoth Cave NP	0.11	0.08	0.86	0.01	0.24	1.54	0.01	11	B20%
Marble Mountain Wilderness	0.03	0.02	0.12	0.01	0.06	0.36	0.01	10	B20%
Maroon Bells-Snowmass Wilderness	0.04	0.03	0.14	0.01	0.08	0.36	0.00	8	B20%
Mazatzal Wilderness	0.06	0.05	0.30	0.01	0.14	0.80	0.00	10	B20%
Medicine Lake Wilderness	0.06	0.05	0.24	0.01	0.20	1.13	0.00	11	B20%
Mesa Verde NP	0.06	0.05	0.24	0.01	0.17	0.67	0.00	9	B20%
Mingo Wilderness	0.12	0.04	0.88	0.01	0.21	1.49	0.01	12	B20%
Mission Mountains Wilderness	0.05	0.04	0.19	0.01	0.08	0.37	0.00	10	B20%
Mokelumne Wilderness	0.04	0.03	0.15	0.01	0.09	0.51	0.01	9	B20%
Moosehorn Wilderness	0.11	0.04	0.76	0.01	0.12	1.25	0.02	12	B20%
Mount Adams Wilderness	0.02	0.01	0.06	0.00	0.04	0.21	0.01	10	B20%
Mount Baldy Wilderness	0.05	0.04	0.19	0.01	0.11	0.53	0.00	9	B20%
Mount Hood Wilderness	0.02	0.02	0.06	0.00	0.05	0.15	0.01	10	B20%

Table 5. 20% Best Natural Conditions – Concentrations and Rayleigh Scattering By Class I Area

Class I Area	$(NH_4)_2SO_4$ µg/m3	NH_4NO_3 µg/m3	OM µg/m³	EC µg/m³	Soil µg/m³	CM µg/m³	Sea Salt µg/m³	Rayleigh Mm^{-1}	Type
Mount Jefferson Wilderness	0.02	0.02	0.08	0.00	0.03	0.31	0.01	11	B20%
Mount Rainier NP	0.03	0.02	0.18	0.01	0.06	0.83	0.02	11	B20%
Mount Washington Wilderness	0.02	0.02	0.08	0.00	0.03	0.31	0.01	11	B20%
Mount Zirkel Wilderness	0.06	0.04	0.16	0.01	0.09	0.60	0.00	8	B20%
Mountain Lakes Wilderness	0.02	0.02	0.08	0.01	0.07	0.23	0.01	9	B20%
North Absaroka Wilderness	0.05	0.04	0.16	0.00	0.11	0.82	0.00	9	B20%
North Cascades NP	0.02	0.03	0.09	0.00	0.04	0.28	0.01	11	B20%
Okefenokee Wilderness	0.13	0.07	0.92	0.01	0.22	1.69	0.03	11	B20%
Olympic NP	0.04	0.03	0.23	0.01	0.03	0.50	0.04	11	B20%
Otter Creek Wilderness	0.10	0.05	0.80	0.01	0.17	0.96	0.01	10	B20%
Pasayten Wilderness	0.04	0.03	0.07	0.00	0.07	0.24	0.01	10	B20%
Pecos Wilderness	0.04	0.03	0.16	0.01	0.08	0.67	0.00	8	B20%
Petrified Forest NP	0.06	0.06	0.28	0.01	0.15	0.75	0.00	9	B20%
Pine Mountain Wilderness	0.06	0.05	0.30	0.01	0.14	0.80	0.00	10	B20%
Pinnacles NM	0.06	0.04	0.31	0.01	0.16	1.50	0.06	11	B20%
Point Reyes NS	0.12	0.04	0.33	0.01	0.13	1.08	0.25	12	B20%
Presidential Range-Dry River Wilderness	0.09	0.04	0.56	0.01	0.10	1.05	0.02	11	B20%
Rawah Wilderness	0.06	0.04	0.16	0.01	0.09	0.60	0.00	8	B20%
Red Rock Lakes Wilderness	0.06	0.05	0.17	0.01	0.08	0.33	0.00	9	B20%
Redwood NP	0.05	0.03	0.28	0.01	0.06	1.02	0.10	11	B20%
Rocky Mountain NP	0.04	0.02	0.15	0.01	0.09	0.68	0.00	9	B20%
Roosevelt Campobello International Park	0.11	0.04	0.76	0.01	0.12	1.25	0.02	12	B20%
Saguaro NP	0.07	0.05	0.32	0.01	0.22	1.15	0.03	10	B20%
Saint Marks Wilderness	0.14	0.06	0.81	0.01	0.24	2.17	0.04	11	B20%
Salt Creek Wilderness	0.05	0.06	0.31	0.01	0.17	1.00	0.02	10	B20%
San Gabriel Wilderness	0.03	0.03	0.15	0.01	0.14	0.67	0.01	9	B20%
San Gorgonio Wilderness	0.03	0.02	0.15	0.01	0.10	0.62	0.02	10	B20%
San Jacinto Wilderness	0.03	0.02	0.15	0.01	0.10	0.62	0.02	10	B20%
San Pedro Parks Wilderness	0.05	0.04	0.14	0.01	0.09	0.34	0.01	8	B20%
San Rafael Wilderness	0.03	0.04	0.22	0.01	0.11	0.79	0.02	10	B20%
Sawtooth Wilderness	0.05	0.04	0.23	0.01	0.10	0.37	0.00	10	B20%
Scapegoat Wilderness	0.05	0.04	0.19	0.01	0.08	0.37	0.00	10	B20%
Selway-Bitterroot Wilderness	0.04	0.03	0.12	0.01	0.07	0.31	0.00	10	B20%
Seney Wilderness	0.08	0.01	0.38	0.01	0.09	0.80	0.01	12	B20%
Sequoia NP	0.03	0.03	0.18	0.01	0.08	0.73	0.02	11	B20%
Shenandoah NP	0.08	0.07	0.56	0.01	0.14	1.20	0.01	10	B20%
Shining Rock Wilderness	0.05	0.05	0.51	0.01	0.13	0.56	0.01	10	B20%
Sierra Ancha Wilderness	0.06	0.05	0.33	0.02	0.14	0.73	0.01	10	B20%
Simeonof Wilderness	0.06	0.05	0.25	0.02	0.04	1.18	0.25	12	B20%
Sipsey Wilderness	0.11	0.10	0.81	0.01	0.25	1.66	0.01	11	B20%
South Warner Wilderness	0.03	0.03	0.14	0.01	0.06	0.46	0.00	10	B20%
Strawberry Mountain Wilderness	0.05	0.02	0.17	0.01	0.10	0.50	0.01	10	B20%
Superstition Wilderness	0.07	0.05	0.31	0.01	0.16	0.84	0.00	10	B20%

Table 5. 20% Best Natural Conditions – Concentrations and Rayleigh Scattering By Class I Area									
Class I Area	$(NH_4)_2SO_4$ µg/m3	NH_4NO_3 µg/m3	OM µg/m³	EC µg/m³	Soil µg/m³	CM µg/m³	Sea Salt µg/m³	Rayleigh Mm^{-1}	Type
Swanquarter Wilderness	0.12	0.06	0.65	0.01	0.23	2.38	0.05	12	B20%
Sycamore Canyon Wilderness	0.06	0.05	0.28	0.01	0.12	0.62	0.00	9	B20%
Teton Wilderness	0.06	0.05	0.17	0.01	0.08	0.33	0.00	9	B20%
Theodore Roosevelt NP	0.07	0.04	0.26	0.01	0.21	1.20	0.01	11	B20%
Thousand Lakes Wilderness	0.03	0.02	0.12	0.01	0.08	0.24	0.01	10	B20%
Three Sisters Wilderness	0.02	0.02	0.08	0.00	0.03	0.31	0.01	11	B20%
Tuxedni Wilderness	0.03	0.04	0.09	0.01	0.03	0.52	0.05	12	B20%
UL Bend Wilderness	0.05	0.03	0.18	0.01	0.15	0.93	0.01	11	B20%
Upper Buffalo Wilderness	0.08	0.06	0.68	0.01	0.16	1.33	0.01	11	B20%
Ventana Wilderness	0.06	0.04	0.31	0.01	0.16	1.50	0.06	11	B20%
Virgin Islands NP	0.18	0.07	0.21	0.01	0.12	1.53	0.26	11	B20%
Voyageurs NP	0.12	0.02	0.56	0.01	0.10	0.86	0.01	12	B20%
Washakie Wilderness	0.05	0.04	0.16	0.00	0.11	0.82	0.00	9	B20%
Weminuche Wilderness	0.06	0.04	0.24	0.01	0.13	0.88	0.00	9	B20%
West Elk Wilderness	0.04	0.03	0.14	0.01	0.08	0.36	0.00	8	B20%
Wheeler Peak Wilderness	0.04	0.03	0.16	0.01	0.08	0.67	0.00	8	B20%
White Mountain Wilderness	0.05	0.03	0.24	0.01	0.08	0.67	0.01	9	B20%
Wichita Mountains Wilderness	0.03	0.04	0.28	0.01	0.15	1.52	0.01	11	B20%
Wind Cave NP	0.05	0.04	0.20	0.01	0.19	1.05	0.00	10	B20%
Wolf Island Wilderness	0.13	0.07	0.92	0.01	0.22	1.69	0.03	11	B20%
Yellowstone NP	0.06	0.05	0.17	0.01	0.08	0.33	0.00	9	B20%
Yolla Bolly-Middle Eel Wilderness	0.03	0.02	0.12	0.01	0.06	0.36	0.01	10	B20%
Yosemite NP	0.03	0.02	0.10	0.00	0.08	0.50	0.01	10	B20%
Zion NP	0.05	0.06	0.28	0.01	0.10	0.60	0.01	10	B20%

Table 6. Annual Average Natural Conditions - Concentrations and Rayleigh Scattering By Class I Area

Class I Area	$(NH_4)_2SO_4$ µg/m3	NH_4NO_3 µg/m3	OM µg/m³	EC µg/m³	Soil µg/m³	CM µg/m³	Sea Salt µg/m³	Rayleigh Mm^{-1}	Type
Acadia NP	0.23	0.10	1.67	0.02	0.25	2.14	0.14	12	Annual
Agua Tibia Wilderness	0.12	0.10	0.60	0.02	0.50	3.00	0.14	11	Annual
Alpine Lakes Wilderness	0.12	0.10	0.60	0.02	0.23	1.30	0.06	11	Annual
Anaconda Pintler Wilderness	0.12	0.10	0.60	0.02	0.39	1.79	0.02	10	Annual
Ansel Adams Wilderness	0.12	0.10	0.58	0.02	0.46	2.88	0.03	9	Annual
Arches NP	0.12	0.10	0.60	0.02	0.50	2.92	0.01	9	Annual
Badlands NP	0.12	0.10	0.60	0.02	0.50	3.00	0.01	11	Annual
Bandelier NM	0.12	0.10	0.60	0.02	0.50	2.86	0.02	9	Annual
Bering Sea Wilderness									Annual
Big Bend NP	0.12	0.10	0.60	0.02	0.50	3.00	0.03	10	Annual
Black Canyon of the Gunnison NP	0.12	0.10	0.60	0.02	0.49	2.59	0.01	9	Annual
Bob Marshall Wilderness	0.12	0.10	0.60	0.02	0.44	2.34	0.01	10	Annual
Bosque del Apache Wilderness	0.12	0.10	0.60	0.02	0.50	3.00	0.04	10	Annual
Boundary Waters Canoe Area Wilderness	0.23	0.10	1.71	0.02	0.31	2.53	0.02	11	Annual
Breton Wilderness	0.23	0.10	1.78	0.02	0.48	3.01	0.19	11	Annual
Bridger Wilderness	0.12	0.10	0.60	0.02	0.44	1.88	0.01	9	Annual
Brigantine Wilderness	0.23	0.10	1.80	0.02	0.47	3.00	0.22	12	Annual
Bryce Canyon NP	0.12	0.10	0.60	0.02	0.50	2.87	0.01	9	Annual
Cabinet Mountains Wilderness	0.12	0.10	0.60	0.02	0.41	2.31	0.02	10	Annual
Caney Creek Wilderness	0.23	0.10	1.80	0.02	0.50	3.00	0.03	11	Annual
Canyonlands NP	0.12	0.10	0.60	0.02	0.50	2.92	0.01	9	Annual
Cape Romain Wilderness	0.23	0.10	1.80	0.02	0.45	3.00	0.20	12	Annual
Capitol Reef NP	0.11	0.10	0.58	0.02	0.50	2.78	0.00	9	Annual
Caribou Wilderness	0.12	0.10	0.60	0.02	0.44	1.82	0.01	10	Annual
Carlsbad Caverns NP	0.12	0.10	0.60	0.02	0.50	3.00	0.02	9	Annual
Chassahowitzka Wilderness	0.23	0.10	1.81	0.02	0.50	3.00	0.08	11	Annual
Chiricahua NM	0.12	0.10	0.60	0.02	0.50	3.00	0.02	10	Annual
Chiricahua Wilderness	0.12	0.10	0.60	0.02	0.50	3.00	0.02	10	Annual
Cohutta Wilderness	0.23	0.10	1.71	0.02	0.50	2.45	0.02	11	Annual
Crater Lake NP	0.12	0.10	0.60	0.02	0.39	1.67	0.02	9	Annual
Craters of the Moon NM	0.12	0.10	0.60	0.02	0.50	2.92	0.01	10	Annual
Cucamonga Wilderness	0.12	0.10	0.60	0.02	0.50	3.00	0.04	9	Annual
Denali NP & Pres	0.12	0.05	0.60	0.02	0.14	1.12	0.04	11	Annual
Desolation Wilderness	0.12	0.10	0.60	0.02	0.43	1.92	0.01	9	Annual
Diamond Peak Wilderness	0.12	0.10	0.60	0.02	0.39	1.67	0.02	9	Annual
Dolly Sods Wilderness	0.23	0.10	1.80	0.02	0.43	2.19	0.02	10	Annual
Dome Land Wilderness	0.12	0.10	0.60	0.02	0.50	3.00	0.03	10	Annual
Eagle Cap Wilderness	0.12	0.10	0.60	0.02	0.50	2.99	0.04	10	Annual
Eagles Nest Wilderness	0.12	0.10	0.60	0.02	0.48	2.12	0.00	8	Annual
Emigrant Wilderness	0.12	0.10	0.60	0.02	0.44	3.00	0.02	10	Annual
Everglades NP	0.23	0.10	1.79	0.02	0.50	3.00	0.31	11	Annual
Fitzpatrick Wilderness	0.12	0.10	0.60	0.02	0.44	1.88	0.01	9	Annual
Flat Tops Wilderness	0.12	0.10	0.60	0.02	0.48	2.12	0.00	8	Annual
Galiuro Wilderness	0.12	0.10	0.60	0.02	0.50	3.00	0.02	10	Annual

Table 6. Annual Average Natural Conditions - Concentrations and Rayleigh Scattering By Class I Area									
Class I Area	$(NH_4)_2SO_4$ µg/m3	NH_4NO_3 µg/m3	OM µg/m³	EC µg/m³	Soil µg/m³	CM µg/m³	Sea Salt µg/m³	Rayleigh Mm^{-1}	Type
Gates of the Mountains Wilderness	0.12	0.10	0.60	0.02	0.35	1.55	0.01	9	Annual
Gearhart Mountain Wilderness	0.12	0.10	0.60	0.02	0.39	1.67	0.02	9	Annual
Gila Wilderness	0.12	0.10	0.60	0.02	0.50	2.54	0.01	9	Annual
Glacier NP	0.11	0.10	0.59	0.02	0.50	3.00	0.01	11	Annual
Glacier Peak Wilderness	0.11	0.10	0.60	0.02	0.19	1.32	0.02	11	Annual
Goat Rocks Wilderness	0.12	0.10	0.60	0.02	0.23	1.23	0.03	10	Annual
Grand Canyon NP	0.12	0.10	0.60	0.02	0.50	2.88	0.02	9	Annual
Grand Teton NP	0.12	0.10	0.60	0.02	0.41	1.92	0.01	9	Annual
Great Gulf Wilderness	0.23	0.10	1.70	0.02	0.25	2.65	0.03	11	Annual
Great Sand Dunes NP & Pres	0.12	0.10	0.60	0.02	0.50	2.99	0.01	9	Annual
Great Smoky Mountains NP	0.23	0.10	1.80	0.02	0.48	2.92	0.02	11	Annual
Guadalupe Mountains NP	0.12	0.10	0.60	0.02	0.50	3.00	0.02	9	Annual
Haleakala NP	0.12	0.10	0.57	0.02	0.23	2.93	0.25	10	Annual
Hawaii Volcanoes NP	0.12	0.10	0.45	0.02	0.16	1.42	0.29	10	Annual
Hells Canyon Wilderness	0.12	0.10	0.60	0.02	0.48	2.97	0.01	11	Annual
Hercules-Glades Wilderness	0.23	0.10	1.80	0.02	0.50	3.00	0.02	11	Annual
Hoover Wilderness	0.12	0.10	0.60	0.02	0.50	2.97	0.01	9	Annual
Isle Royale NP	0.23	0.10	1.55	0.02	0.24	2.89	0.03	12	Annual
James River Face Wilderness	0.23	0.10	1.80	0.02	0.48	3.00	0.02	11	Annual
Jarbidge Wilderness	0.12	0.10	0.60	0.02	0.50	3.00	0.02	10	Annual
John Muir Wilderness	0.12	0.10	0.58	0.02	0.46	2.88	0.03	9	Annual
Joshua Tree NP	0.12	0.10	0.60	0.02	0.50	3.00	0.03	10	Annual
Joyce Kilmer-Slickrock Wilderness	0.23	0.10	1.80	0.02	0.48	2.92	0.02	11	Annual
Kaiser Wilderness	0.12	0.10	0.58	0.02	0.46	2.88	0.03	9	Annual
Kalmiopsis Wilderness	0.12	0.10	0.60	0.02	0.20	2.24	0.23	12	Annual
Kings Canyon	0.11	0.10	0.60	0.02	0.50	3.00	0.04	11	Annual
La Garita Wilderness	0.12	0.10	0.60	0.02	0.49	2.59	0.01	9	Annual
Lassen Volcanic NP	0.12	0.10	0.60	0.02	0.44	1.82	0.01	10	Annual
Lava Beds NM	0.12	0.10	0.60	0.02	0.44	2.36	0.01	10	Annual
Linville Gorge Wilderness	0.23	0.10	1.80	0.02	0.45	2.60	0.02	11	Annual
Lostwood Wilderness	0.12	0.10	0.60	0.02	0.50	3.00	0.03	11	Annual
Lye Brook Wilderness	0.23	0.10	1.59	0.02	0.28	1.79	0.02	11	Annual
Mammoth Cave NP	0.23	0.10	1.80	0.02	0.50	2.73	0.02	11	Annual
Marble Mountain Wilderness	0.12	0.10	0.52	0.02	0.42	2.08	0.04	10	Annual
Maroon Bells-Snowmass Wilderness	0.12	0.10	0.60	0.02	0.48	2.12	0.00	8	Annual
Mazatzal Wilderness	0.12	0.10	0.60	0.02	0.50	3.00	0.02	10	Annual
Medicine Lake Wilderness	0.12	0.10	0.60	0.02	0.48	3.00	0.01	11	Annual
Mesa Verde NP	0.12	0.10	0.60	0.02	0.50	2.88	0.00	9	Annual
Mingo Wilderness	0.23	0.10	1.83	0.02	0.51	3.05	0.04	12	Annual
Mission Mountains Wilderness	0.12	0.10	0.60	0.02	0.44	2.34	0.01	10	Annual
Mokelumne Wilderness	0.12	0.10	0.60	0.02	0.43	1.92	0.01	9	Annual
Moosehorn Wilderness	0.23	0.10	1.79	0.02	0.23	2.56	0.11	12	Annual
Mount Adams Wilderness	0.12	0.10	0.60	0.02	0.23	1.23	0.03	10	Annual

Table 6. Annual Average Natural Conditions - Concentrations and Rayleigh Scattering By Class I Area

Class I Area	$(NH_4)_2SO_4$ µg/m3	NH_4NO_3 µg/m3	OM µg/m³	EC µg/m³	Soil µg/m³	CM µg/m³	Sea Salt µg/m³	Rayleigh Mm^{-1}	Type
Mount Baldy Wilderness	0.12	0.10	0.57	0.02	0.50	2.82	0.01	9	Annual
Mount Hood Wilderness	0.12	0.10	0.60	0.02	0.29	1.58	0.05	10	Annual
Mount Jefferson Wilderness	0.12	0.10	0.60	0.02	0.26	1.98	0.05	11	Annual
Mount Rainier NP	0.12	0.10	0.60	0.02	0.24	2.27	0.07	11	Annual
Mount Washington Wilderness	0.12	0.10	0.60	0.02	0.26	1.98	0.05	11	Annual
Mount Zirkel Wilderness	0.12	0.10	0.60	0.02	0.45	2.69	0.00	8	Annual
Mountain Lakes Wilderness	0.12	0.10	0.60	0.02	0.39	1.67	0.02	9	Annual
North Absaroka Wilderness	0.12	0.10	0.60	0.02	0.43	2.84	0.01	9	Annual
North Cascades NP	0.11	0.10	0.60	0.02	0.19	1.32	0.02	11	Annual
Okefenokee Wilderness	0.23	0.10	1.80	0.02	0.50	3.00	0.08	11	Annual
Olympic NP	0.12	0.10	0.60	0.02	0.15	1.88	0.14	11	Annual
Otter Creek Wilderness	0.23	0.10	1.80	0.02	0.43	2.19	0.02	10	Annual
Pasayten Wilderness	0.12	0.10	0.60	0.02	0.33	1.50	0.01	10	Annual
Pecos Wilderness	0.12	0.10	0.60	0.02	0.50	2.29	0.03	8	Annual
Petrified Forest NP	0.12	0.10	0.60	0.02	0.50	3.00	0.01	9	Annual
Pine Mountain Wilderness	0.12	0.10	0.60	0.02	0.50	3.00	0.02	10	Annual
Pinnacles NM	0.12	0.10	0.60	0.02	0.35	3.00	0.19	11	Annual
Point Reyes NS	0.12	0.10	0.60	0.02	0.24	3.00	2.11	12	Annual
Presidential Range-Dry River Wilderness	0.23	0.10	1.70	0.02	0.25	2.65	0.03	11	Annual
Rawah Wilderness	0.12	0.10	0.60	0.02	0.45	2.69	0.00	8	Annual
Red Rock Lakes Wilderness	0.12	0.10	0.60	0.02	0.41	1.92	0.01	9	Annual
Redwood NP	0.12	0.10	0.60	0.02	0.16	3.00	0.96	11	Annual
Rocky Mountain NP	0.12	0.10	0.60	0.02	0.50	2.90	0.00	9	Annual
Roosevelt Campobello International Park	0.23	0.10	1.79	0.02	0.23	2.56	0.11	12	Annual
Saguaro NP	0.12	0.10	0.60	0.02	0.50	3.00	0.06	10	Annual
Saint Marks Wilderness	0.23	0.10	1.80	0.02	0.50	3.00	0.10	11	Annual
Salt Creek Wilderness	0.12	0.10	0.60	0.02	0.50	3.00	0.04	10	Annual
San Gabriel Wilderness	0.12	0.10	0.60	0.02	0.50	3.00	0.04	9	Annual
San Gorgonio Wilderness	0.12	0.10	0.60	0.02	0.50	3.00	0.05	10	Annual
San Jacinto Wilderness	0.12	0.10	0.60	0.02	0.50	3.00	0.05	10	Annual
San Pedro Parks Wilderness	0.12	0.10	0.60	0.02	0.50	2.19	0.01	8	Annual
San Rafael Wilderness	0.11	0.10	0.60	0.02	0.50	3.00	0.11	10	Annual
Sawtooth Wilderness	0.12	0.08	0.60	0.02	0.41	1.64	0.01	10	Annual
Scapegoat Wilderness	0.12	0.10	0.60	0.02	0.44	2.34	0.01	10	Annual
Selway-Bitterroot Wilderness	0.12	0.10	0.60	0.02	0.39	1.79	0.02	10	Annual
Seney Wilderness	0.23	0.10	1.74	0.02	0.26	1.95	0.02	12	Annual
Sequoia NP	0.11	0.10	0.60	0.02	0.50	3.00	0.04	11	Annual
Shenandoah NP	0.23	0.10	1.80	0.02	0.41	2.88	0.02	10	Annual
Shining Rock Wilderness	0.23	0.10	1.76	0.02	0.50	1.76	0.02	10	Annual
Sierra Ancha Wilderness	0.12	0.10	0.60	0.02	0.50	3.00	0.02	10	Annual
Simeonof Wilderness	0.12	0.10	0.46	0.02	0.13	3.00	1.26	12	Annual
Sipsey Wilderness	0.23	0.10	1.80	0.02	0.50	3.00	0.04	11	Annual
South Warner Wilderness	0.12	0.10	0.60	0.02	0.44	2.36	0.01	10	Annual

Table 6. Annual Average Natural Conditions - Concentrations and Rayleigh Scattering By Class I Area									
Class I Area	$(NH_4)_2SO_4$ µg/m3	NH_4NO_3 µg/m3	OM µg/m³	EC µg/m³	Soil µg/m³	CM µg/m³	Sea Salt µg/m³	Rayleigh Mm^{-1}	Type
Strawberry Mountain Wilderness	0.12	0.10	0.60	0.02	0.50	2.99	0.04	10	Annual
Superstition Wilderness	0.11	0.10	0.59	0.02	0.50	3.00	0.02	10	Annual
Swanquarter Wilderness	0.23	0.10	1.63	0.02	0.41	3.00	0.14	12	Annual
Sycamore Canyon Wilderness	0.12	0.10	0.60	0.02	0.50	3.00	0.03	9	Annual
Teton Wilderness	0.12	0.10	0.60	0.02	0.41	1.92	0.01	9	Annual
Theodore Roosevelt NP	0.12	0.10	0.60	0.02	0.50	3.00	0.01	11	Annual
Thousand Lakes Wilderness	0.12	0.10	0.60	0.02	0.44	1.82	0.01	10	Annual
Three Sisters Wilderness	0.12	0.10	0.60	0.02	0.26	1.98	0.05	11	Annual
Tuxedni Wilderness	0.12	0.09	0.60	0.02	0.10	2.06	0.38	12	Annual
UL Bend Wilderness	0.12	0.10	0.60	0.02	0.45	3.00	0.00	11	Annual
Upper Buffalo Wilderness	0.23	0.10	1.80	0.02	0.50	3.00	0.03	11	Annual
Ventana Wilderness	0.12	0.10	0.60	0.02	0.35	3.00	0.19	11	Annual
Virgin Islands NP	0.23	0.10	0.35	0.02	0.50	3.00	0.84	11	Annual
Voyageurs NP	0.23	0.10	1.75	0.02	0.26	2.73	0.04	12	Annual
Washakie Wilderness	0.12	0.10	0.60	0.02	0.43	2.84	0.01	9	Annual
Weminuche Wilderness	0.12	0.10	0.60	0.02	0.49	2.59	0.01	9	Annual
West Elk Wilderness	0.12	0.10	0.60	0.02	0.48	2.12	0.00	8	Annual
Wheeler Peak Wilderness	0.12	0.10	0.60	0.02	0.50	2.29	0.03	8	Annual
White Mountain Wilderness	0.12	0.10	0.60	0.02	0.50	3.00	0.03	9	Annual
Wichita Mountains Wilderness	0.12	0.10	0.60	0.02	0.50	3.00	0.03	11	Annual
Wind Cave NP	0.12	0.10	0.60	0.02	0.49	2.98	0.01	10	Annual
Wolf Island Wilderness	0.23	0.10	1.80	0.02	0.50	3.00	0.08	11	Annual
Yellowstone NP	0.12	0.10	0.60	0.02	0.41	1.92	0.01	9	Annual
Yolla Bolly-Middle Eel Wilderness	0.12	0.10	0.52	0.02	0.42	2.08	0.04	10	Annual
Yosemite NP	0.12	0.10	0.60	0.02	0.44	3.00	0.02	10	Annual
Zion NP	0.12	0.10	0.60	0.02	0.50	3.00	0.01	10	Annual

Table 7. Monthly $f_L(RH)$ – Large $(NH_4)_2SO_4$ and NH_4NO_3 Relative Humidity Adjustment Factor												
Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Acadia NP	2.74	2.46	2.45	2.66	2.67	2.73	2.99	3.03	3.16	2.91	2.89	2.96
Agua Tibia Wilderness	2.10	2.08	2.11	1.98	1.98	1.93	1.93	2.01	2.02	1.99	1.87	1.95
Alpine Lakes Wilderness	3.86	3.58	3.04	2.92	2.99	2.58	2.62	2.67	2.97	3.60	4.00	3.99
Anaconda Pintler Wilderness	2.75	2.46	2.24	2.08	2.06	2.01	1.76	1.72	1.88	2.22	2.66	2.74
Ansel Adams Wilderness	2.56	2.34	2.20	1.88	1.79	1.59	1.52	1.52	1.59	1.70	2.01	2.34
Arches NP	2.28	2.12	1.73	1.57	1.50	1.28	1.34	1.47	1.51	1.56	1.90	2.13
Badlands NP	2.31	2.31	2.31	2.21	2.34	2.25	2.08	2.05	2.02	2.05	2.38	2.33
Bandelier NM	2.10	1.90	1.72	1.51	1.53	1.38	1.63	1.87	1.80	1.59	1.87	2.04
Bering Sea Wilderness	3.02	3.17	3.20	3.19	3.23	3.34	3.78	4.16	3.64	3.19	3.12	3.13
Big Bend NP	1.72	1.61	1.44	1.38	1.47	1.48	1.58	1.74	1.83	1.63	1.63	1.70
Black Canyon of the Gunnison NP	2.15	2.05	1.83	1.75	1.74	1.51	1.59	1.78	1.80	1.68	1.96	2.06
Bob Marshall Wilderness	2.82	2.54	2.35	2.22	2.21	2.19	1.98	1.92	2.15	2.43	2.78	2.81
Bosque del Apache Wilderness	2.03	1.82	1.55	1.37	1.36	1.27	1.61	1.79	1.73	1.54	1.73	2.00
Boundary Waters Canoe Area Wilderness	2.50	2.25	2.28	2.09	2.20	2.43	2.57	2.71	2.78	2.38	2.64	2.64
Breton Wilderness	2.91	2.76	2.74	2.72	2.83	2.94	3.10	3.07	2.97	2.82	2.83	2.90
Bridger Wilderness	2.22	2.10	2.04	1.95	1.95	1.67	1.46	1.44	1.68	1.83	2.19	2.16
Brigantine Wilderness	2.49	2.32	2.38	2.28	2.50	2.56	2.69	2.81	2.82	2.71	2.45	2.50
Bryce Canyon NP	2.31	2.16	1.82	1.56	1.47	1.26	1.30	1.46	1.46	1.55	1.87	2.15
Cabinet Mountains Wilderness	3.07	2.73	2.45	2.26	2.24	2.21	1.98	1.92	2.19	2.53	3.03	3.11
Caney Creek Wilderness	2.77	2.53	2.37	2.43	2.68	2.71	2.59	2.60	2.71	2.69	2.67	2.79
Canyonlands NP	2.32	2.16	1.78	1.58	1.51	1.28	1.36	1.53	1.55	1.58	1.93	2.17
Cape Romain Wilderness	2.66	2.47	2.42	2.32	2.56	2.80	2.82	3.04	3.03	2.86	2.65	2.70
Capitol Reef NP	2.36	2.22	1.84	1.63	1.54	1.31	1.36	1.52	1.55	1.61	1.95	2.22
Caribou Wilderness	2.96	2.58	2.35	2.10	2.01	1.85	1.79	1.82	1.88	2.03	2.50	2.82
Carlsbad Caverns NP	2.07	1.81	1.50	1.42	1.51	1.48	1.72	1.90	2.03	1.64	1.76	2.00
Chassahowitzka Wilderness	3.03	2.82	2.74	2.65	2.63	3.00	3.02	3.15	3.14	3.03	2.97	3.09
Chiricahua NM	1.87	1.79	1.52	1.24	1.22	1.13	1.64	1.87	1.66	1.45	1.55	1.89
Chiricahua Wilderness	1.84	1.76	1.49	1.22	1.20	1.12	1.64	1.86	1.64	1.43	1.53	1.87
Cohutta Wilderness	2.84	2.61	2.49	2.36	2.72	2.97	3.00	3.07	3.08	2.89	2.72	2.85
Crater Lake NP	3.71	3.25	3.07	2.91	2.70	2.50	2.31	2.33	2.49	2.99	3.67	3.74
Craters of the Moon NM	2.58	2.34	2.03	1.84	1.83	1.65	1.40	1.39	1.52	1.80	2.35	2.54
Cucamonga Wilderness	2.21	2.14	2.13	1.96	1.95	1.90	1.91	1.96	1.98	1.96	1.90	2.02
Denali NP & Pres	2.48	2.44	2.15	1.96	1.98	2.13	2.47	2.90	2.95	2.84	2.69	2.68
Desolation Wilderness	2.73	2.42	2.18	1.84	1.74	1.56	1.47	1.49	1.58	1.73	2.12	2.54
Diamond Peak Wilderness	3.82	3.38	3.18	3.04	2.79	2.60	2.33	2.35	2.58	3.18	3.80	3.86
Dolly Sods Wilderness	2.53	2.39	2.38	2.20	2.63	2.65	2.74	2.90	2.94	2.65	2.45	2.61
Dome Land Wilderness	2.26	2.07	2.00	1.79	1.73	1.63	1.61	1.64	1.68	1.71	1.81	2.01
Eagle Cap Wilderness	3.44	3.02	2.54	2.31	2.28	2.01	1.78	1.75	1.97	2.61	3.34	3.56
Eagles Nest Wilderness	2.02	2.01	1.87	1.87	1.92	1.69	1.68	1.83	1.86	1.73	1.96	1.97
Emigrant Wilderness	2.67	2.42	2.26	1.92	1.81	1.59	1.49	1.50	1.58	1.72	2.08	2.45
Everglades NP	2.43	2.31	2.26	2.16	2.15	2.38	2.32	2.49	2.55	2.42	2.34	2.39
Fitzpatrick Wilderness	2.22	2.10	2.04	1.95	1.94	1.68	1.47	1.44	1.68	1.83	2.18	2.16
Flat Tops Wilderness	2.09	2.04	1.87	1.84	1.86	1.62	1.59	1.70	1.79	1.72	1.97	2.03
Galiuro Wilderness	1.80	1.67	1.47	1.21	1.18	1.10	1.43	1.66	1.53	1.42	1.57	1.87
Gates of the Mountains Wilderness	2.46	2.25	2.15	2.05	2.02	2.00	1.81	1.77	1.91	2.15	2.37	2.41

Table 7. Monthly $f_L(RH)$ – Large $(NH_4)_2SO_4$ and NH_4NO_3 Relative Humidity Adjustment Factor												
Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gearhart Mountain Wilderness	3.30	2.89	2.62	2.45	2.29	2.13	1.88	1.90	2.03	2.47	3.09	3.27
Gila Wilderness	1.93	1.78	1.52	1.31	1.28	1.23	1.72	1.76	1.68	1.50	1.67	1.96
Glacier NP	3.21	2.84	2.69	2.55	2.58	2.56	2.24	2.22	2.57	2.81	3.08	3.13
Glacier Peak Wilderness	3.69	3.39	2.97	2.85	2.79	2.54	2.49	2.59	2.91	3.45	3.83	3.84
Goat Rocks Wilderness	3.83	3.44	3.10	2.97	2.82	2.60	2.48	2.55	2.88	3.49	3.91	3.98
Grand Canyon NP	2.13	2.01	1.74	1.46	1.36	1.19	1.29	1.49	1.47	1.50	1.75	1.98
Grand Teton NP	2.27	2.14	2.01	1.91	1.90	1.68	1.48	1.44	1.64	1.84	2.16	2.24
Great Gulf Wilderness	2.51	2.32	2.36	2.41	2.45	2.55	2.72	2.87	2.98	2.80	2.67	2.60
Great Sand Dunes NP & Pres	2.11	2.04	1.85	1.77	1.80	1.62	1.70	1.97	1.92	1.72	2.04	2.09
Great Smoky Mountains NP	2.85	2.57	2.51	2.35	2.72	2.98	2.98	3.08	3.10	2.87	2.71	2.85
Guadalupe Mountains NP	2.14	1.82	1.49	1.38	1.48	1.47	1.78	1.98	2.10	1.60	1.78	2.08
Haleakala NP	2.34	2.27	2.25	2.20	2.13	2.09	2.16	2.14	2.10	2.19	2.33	2.30
Hawaii Volcanoes NP	2.56	2.45	2.47	2.47	2.47	2.45	2.53	2.59	2.55	2.57	2.78	2.55
Hells Canyon Wilderness	3.05	2.65	2.22	1.97	1.91	1.81	1.55	1.52	1.68	2.15	2.90	3.15
Hercules-Glades Wilderness	2.70	2.48	2.30	2.30	2.57	2.59	2.56	2.60	2.69	2.54	2.57	2.72
Hoover Wilderness	2.63	2.38	2.21	1.88	1.77	1.56	1.46	1.47	1.55	1.69	2.05	2.42
Isle Royale NP	2.53	2.21	2.26	2.07	1.99	2.32	2.65	2.69	2.82	2.28	2.76	2.74
James River Face Wilderness	2.44	2.30	2.29	2.12	2.47	2.58	2.65	2.78	2.82	2.57	2.36	2.51
Jarbidge Wilderness	2.51	2.28	1.90	1.92	1.97	1.82	1.51	1.37	1.34	1.56	2.14	2.42
John Muir Wilderness	2.51	2.29	2.20	1.95	1.86	1.65	1.60	1.61	1.69	1.78	2.03	2.28
Joshua Tree NP	2.06	1.99	1.97	1.82	1.81	1.74	1.68	1.82	1.83	1.81	1.75	1.87
Joyce Kilmer-Slickrock Wilderness	2.86	2.58	2.51	2.36	2.71	2.97	2.98	3.06	3.08	2.87	2.72	2.85
Kaiser Wilderness	2.58	2.35	2.22	1.90	1.80	1.62	1.56	1.57	1.64	1.75	2.03	2.36
Kalmiopsis Wilderness	3.57	3.17	3.03	2.88	2.75	2.60	2.52	2.53	2.60	2.92	3.51	3.55
Kings Canyon	2.47	2.26	2.18	1.94	1.85	1.65	1.59	1.60	1.68	1.77	2.01	2.24
La Garita Wilderness	2.14	2.03	1.81	1.70	1.69	1.49	1.63	1.87	1.83	1.67	1.98	2.08
Lassen Volcanic NP	2.99	2.61	2.38	2.13	2.03	1.86	1.81	1.84	1.90	2.06	2.54	2.86
Lava Beds NM	3.31	2.88	2.64	2.44	2.29	2.13	1.98	1.99	2.10	2.43	3.03	3.26
Linville Gorge Wilderness	2.71	2.54	2.48	2.31	2.70	2.96	3.00	3.20	3.19	2.84	2.62	2.74
Lostwood Wilderness	2.51	2.45	2.54	2.06	2.03	2.21	2.23	2.05	2.02	2.13	2.69	2.67
Lye Brook Wilderness	2.46	2.30	2.34	2.31	2.42	2.47	2.60	2.76	2.84	2.70	2.54	2.51
Mammoth Cave NP	2.79	2.57	2.47	2.56	3.29	3.76	3.67	2.92	2.95	2.71	2.61	2.82
Marble Mountain Wilderness	3.48	3.08	2.95	2.78	2.67	2.53	2.50	2.52	2.55	2.78	3.32	3.42
Maroon Bells-Snowmass Wilderness	2.02	1.99	1.84	1.84	1.83	1.59	1.69	1.90	1.89	1.71	1.94	1.96
Mazatzal Wilderness	1.91	1.80	1.59	1.32	1.25	1.13	1.38	1.61	1.51	1.45	1.63	1.89
Medicine Lake Wilderness	2.53	2.46	2.46	2.02	2.00	2.13	2.12	1.95	1.98	2.10	2.63	2.65
Mesa Verde NP	2.45	2.25	1.98	1.57	1.61	1.31	1.62	1.87	1.75	1.66	2.01	2.30
Mingo Wilderness	2.73	2.52	2.34	2.28	2.53	2.60	2.64	2.67	2.71	2.56	2.56	2.73
Mission Mountains Wilderness	2.93	2.62	2.37	2.20	2.21	2.19	1.98	1.92	2.15	2.46	2.91	2.96
Mokelumne Wilderness	2.72	2.42	2.20	1.86	1.75	1.57	1.48	1.50	1.58	1.73	2.11	2.52
Moosehorn Wilderness	2.65	2.39	2.38	2.52	2.49	2.57	2.83	2.95	3.07	2.83	2.77	2.78
Mount Adams Wilderness	3.78	3.40	3.10	2.98	2.78	2.60	2.43	2.52	2.84	3.45	3.87	3.92
Mount Baldy Wilderness	2.00	1.86	1.62	1.34	1.29	1.18	1.50	1.73	1.60	1.51	1.73	2.01
Mount Hood Wilderness	3.71	3.33	3.08	2.96	2.74	2.55	2.34	2.42	2.72	3.35	3.81	3.84
Mount Jefferson Wilderness	3.89	3.48	3.27	3.16	2.89	2.66	2.35	2.35	2.63	3.34	3.92	3.95

Table 7. Monthly $f_L(RH)$ – Large $(NH_4)_2SO_4$ and NH_4NO_3 Relative Humidity Adjustment Factor												
Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mount Rainier NP	3.93	3.54	3.23	3.12	2.96	2.75	2.61	2.69	3.04	3.66	4.04	4.07
Mount Washington Wilderness	4.09	3.63	3.49	3.41	3.06	2.80	2.37	2.34	2.62	3.41	4.07	4.10
Mount Zirkel Wilderness	2.00	1.99	1.89	1.92	1.98	1.72	1.63	1.70	1.81	1.75	1.97	1.95
Mountain Lakes Wilderness	3.51	3.03	2.80	2.62	2.44	2.25	2.08	2.09	2.23	2.65	3.37	3.52
North Absaroka Wilderness	2.16	2.05	2.01	1.95	1.94	1.77	1.58	1.50	1.67	1.87	2.12	2.14
North Cascades NP	3.60	3.32	2.99	2.88	2.74	2.59	2.49	2.63	2.97	3.43	3.77	3.76
Okefenokee Wilderness	2.94	2.73	2.73	2.65	2.74	3.11	3.00	3.17	3.16	3.05	2.96	3.03
Olympic NP	3.80	3.50	3.30	3.21	2.76	2.89	2.61	2.94	3.23	3.73	3.99	3.95
Otter Creek Wilderness	2.55	2.41	2.40	2.23	2.64	2.69	2.80	2.96	3.00	2.69	2.48	2.63
Pasayten Wilderness	3.65	3.34	2.97	2.84	2.72	2.53	2.45	2.56	2.88	3.39	3.78	3.81
Pecos Wilderness	2.09	1.93	1.73	1.57	1.58	1.44	1.65	1.90	1.84	1.63	1.90	2.05
Petrified Forest NP	2.11	1.95	1.64	1.40	1.32	1.18	1.46	1.72	1.58	1.53	1.81	2.09
Pine Mountain Wilderness	1.96	1.86	1.64	1.35	1.28	1.15	1.38	1.62	1.53	1.48	1.66	1.93
Pinnacles NM	2.84	2.86	2.87	2.27	2.15	1.99	1.91	1.97	1.98	2.10	2.16	2.46
Point Reyes NS	2.96	2.73	2.61	2.28	2.20	2.04	2.12	2.16	2.18	2.23	2.47	2.75
Presidential Range-Dry River Wilderness	2.52	2.32	2.37	2.42	2.49	2.61	2.78	2.93	3.03	2.83	2.68	2.59
Rawah Wilderness	1.91	1.96	1.89	1.96	2.04	1.79	1.71	1.78	1.86	1.75	1.94	1.90
Red Rock Lakes Wilderness	2.39	2.20	2.06	1.95	1.92	1.80	1.60	1.54	1.69	1.93	2.30	2.37
Redwood NP	3.31	3.10	3.16	3.04	3.11	3.08	3.26	3.28	3.11	2.99	3.20	3.12
Rocky Mountain NP	1.77	1.85	1.84	1.95	2.04	1.80	1.73	1.77	1.84	1.70	1.84	1.76
Roosevelt Campobello International Park	2.66	2.39	2.38	2.53	2.49	2.57	2.82	2.93	3.05	2.83	2.78	2.79
Saguaro NP	1.69	1.56	1.40	1.13	1.12	1.05	1.37	1.62	1.47	1.38	1.50	1.83
Saint Marks Wilderness	2.98	2.78	2.73	2.69	2.74	3.04	3.17	3.21	3.10	2.96	2.94	3.06
Salt Creek Wilderness	2.01	1.79	1.51	1.45	1.55	1.48	1.64	1.80	1.91	1.64	1.72	1.91
San Gabriel Wilderness	2.25	2.17	2.14	1.96	1.95	1.90	1.91	1.95	1.98	1.97	1.91	2.04
San Gorgonio Wilderness	2.21	2.23	2.13	1.90	1.90	1.69	1.62	1.71	1.72	1.70	1.73	1.92
San Jacinto Wilderness	2.12	2.09	2.06	1.90	1.90	1.81	1.71	1.88	1.89	1.87	1.80	1.92
San Pedro Parks Wilderness	2.14	1.97	1.73	1.55	1.53	1.38	1.59	1.83	1.77	1.61	1.91	2.08
San Rafael Wilderness	2.50	2.37	2.34	2.12	2.10	2.05	2.10	2.15	2.20	2.15	2.07	2.25
Sawtooth Wilderness	2.79	2.44	2.05	1.83	1.80	1.66	1.37	1.35	1.43	1.77	2.47	2.75
Scapegoat Wilderness	2.74	2.47	2.30	2.18	2.16	2.14	1.93	1.87	2.07	2.35	2.70	2.72
Selway-Bitterroot Wilderness	2.90	2.57	2.26	2.05	2.03	1.95	1.67	1.63	1.81	2.19	2.76	2.91
Seney Wilderness	2.75	2.42	2.49	2.35	2.30	2.55	2.75	3.01	3.03	2.78	2.88	2.85
Sequoia NP	2.40	2.22	2.21	2.05	1.95	1.67	1.60	1.59	1.69	1.78	2.04	2.17
Shenandoah NP	2.44	2.28	2.29	2.12	2.45	2.56	2.65	2.79	2.81	2.53	2.34	2.55
Shining Rock Wilderness	2.78	2.56	2.48	2.33	2.72	2.98	3.02	3.17	3.18	2.91	2.68	2.79
Sierra Ancha Wilderness	1.92	1.81	1.59	1.32	1.25	1.13	1.42	1.65	1.54	1.47	1.66	1.93
Simeonof Wilderness	3.39	3.40	3.15	3.26	3.40	3.69	4.00	4.14	3.61	3.09	3.21	3.44
Sipsey Wilderness	2.79	2.58	2.42	2.36	2.64	2.86	2.94	2.92	2.93	2.78	2.64	2.80
South Warner Wilderness	3.06	2.67	2.39	2.16	2.05	1.90	1.68	1.69	1.79	2.11	2.67	2.97
Strawberry Mountain Wilderness	3.55	3.10	2.69	2.47	2.37	2.10	1.82	1.81	2.05	2.73	3.45	3.65
Superstition Wilderness	1.84	1.72	1.53	1.26	1.20	1.11	1.36	1.56	1.46	1.40	1.58	1.85
Swanquarter Wilderness	2.48	2.35	2.31	2.18	2.38	2.55	2.67	2.72	2.64	2.55	2.40	2.49
Sycamore Canyon Wilderness	2.01	1.93	1.70	1.40	1.33	1.17	1.38	1.67	1.58	1.52	1.70	1.97
Teton Wilderness	2.22	2.09	2.01	1.92	1.91	1.72	1.52	1.47	1.65	1.86	2.15	2.19

Table 7. Monthly $f_L(RH)$ – Large $(NH_4)_2SO_4$ and NH_4NO_3 Relative Humidity Adjustment Factor												
Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Theodore Roosevelt NP	2.47	2.42	2.45	2.12	2.14	2.21	2.14	1.99	1.99	2.10	2.58	2.57
Thousand Lakes Wilderness	3.04	2.63	2.42	2.17	2.06	1.88	1.82	1.85	1.91	2.08	2.61	2.91
Three Sisters Wilderness	4.03	3.59	3.43	3.34	3.02	2.78	2.40	2.38	2.65	3.39	4.02	4.04
Tuxedni Wilderness	2.97	2.83	2.47	2.40	2.38	2.50	2.96	3.19	3.18	2.91	2.91	3.03
UL Bend Wilderness	2.33	2.20	2.19	2.03	1.96	1.95	1.80	1.66	1.76	2.00	2.31	2.32
Upper Buffalo Wilderness	2.71	2.48	2.31	2.33	2.61	2.64	2.57	2.59	2.71	2.58	2.59	2.72
Ventana Wilderness	2.80	2.67	2.63	2.20	2.10	1.96	1.97	2.01	2.05	2.11	2.21	2.51
Virgin Islands NP	2.04	2.00	1.94	2.03	2.06	2.04	2.05	2.14	2.14	2.18	2.20	2.12
Voyageurs NP	2.46	2.22	2.22	2.07	2.09	2.46	2.46	2.59	2.70	2.35	2.58	2.55
Washakie Wilderness	2.16	2.05	2.01	1.94	1.93	1.74	1.54	1.48	1.66	1.86	2.12	2.14
Weminuche Wilderness	2.19	2.05	1.81	1.65	1.64	1.44	1.60	1.85	1.79	1.65	1.97	2.11
West Elk Wilderness	2.11	2.04	1.84	1.77	1.77	1.54	1.63	1.83	1.83	1.69	1.96	2.04
Wheeler Peak Wilderness	2.14	2.00	1.78	1.65	1.67	1.52	1.66	1.94	1.89	1.68	1.98	2.10
White Mountain Wilderness	2.00	1.79	1.51	1.40	1.44	1.37	1.64	1.82	1.85	1.59	1.72	1.95
Wichita Mountains Wilderness	2.39	2.25	2.10	2.11	2.39	2.24	2.02	2.13	2.35	2.22	2.28	2.41
Wind Cave NP	2.23	2.22	2.22	2.18	2.32	2.18	2.00	1.97	1.95	2.00	2.30	2.24
Wolf Island Wilderness	2.86	2.67	2.61	2.54	2.63	2.96	2.94	3.13	3.12	2.99	2.88	2.95
Yellowstone NP	2.24	2.11	2.03	1.95	1.94	1.78	1.59	1.53	1.69	1.91	2.19	2.22
Yolla Bolly-Middle Eel Wilderness	3.12	2.76	2.60	2.37	2.29	2.13	2.14	2.18	2.21	2.33	2.75	2.98
Yosemite NP	2.61	2.45	2.34	1.99	1.88	1.61	1.48	1.46	1.54	1.69	2.06	2.38
Zion NP	2.32	2.18	1.83	1.56	1.45	1.26	1.24	1.38	1.40	1.51	1.84	2.14

Table 8. Monthly $f_S(RH)$ – Small $(NH_4)_2SO_4$ and NH_4NO_3 Relative Humidity Adjustment Factor												
Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Acadia NP	3.80	3.28	3.30	3.71	3.72	3.81	4.28	4.34	4.58	4.10	4.06	4.19
Agua Tibia Wilderness	2.68	2.61	2.63	2.42	2.40	2.33	2.33	2.45	2.49	2.46	2.29	2.42
Alpine Lakes Wilderness	5.87	5.35	4.34	4.13	4.30	3.50	3.61	3.69	4.27	5.43	6.15	6.08
Anaconda Pintler Wilderness	3.72	3.23	2.87	2.62	2.60	2.52	2.14	2.07	2.33	2.87	3.60	3.71
Ansel Adams Wilderness	3.51	3.11	2.87	2.34	2.18	1.86	1.75	1.76	1.88	2.05	2.55	3.12
Arches NP	2.96	2.70	2.09	1.84	1.75	1.40	1.49	1.69	1.76	1.83	2.33	2.69
Badlands NP	2.94	2.96	3.01	2.87	3.10	2.91	2.64	2.59	2.56	2.58	3.11	2.98
Bandelier NM	2.66	2.36	2.10	1.77	1.80	1.55	1.93	2.30	2.21	1.87	2.32	2.60
Bering Sea Wilderness	4.16	4.48	4.52	4.50	4.64	4.86	5.71	6.43	5.40	4.52	4.36	4.37
Big Bend NP	2.11	1.92	1.65	1.56	1.67	1.67	1.83	2.07	2.22	1.92	1.92	2.04
Black Canyon of the Gunnison NP	2.71	2.56	2.23	2.12	2.12	1.75	1.87	2.17	2.21	2.00	2.42	2.57
Bob Marshall Wilderness	3.84	3.35	3.06	2.86	2.86	2.84	2.49	2.39	2.77	3.22	3.81	3.83
Bosque del Apache Wilderness	2.56	2.23	1.83	1.54	1.54	1.39	1.90	2.16	2.09	1.79	2.09	2.53
Boundary Waters Canoe Area Wilderness	3.23	2.81	2.93	2.63	2.89	3.22	3.44	3.71	3.83	3.08	3.49	3.49
Breton Wilderness	4.08	3.82	3.79	3.74	3.94	4.12	4.41	4.37	4.18	3.92	3.93	4.06
Bridger Wilderness	2.78	2.60	2.55	2.43	2.45	1.99	1.65	1.63	2.03	2.25	2.78	2.68
Brigantine Wilderness	3.34	3.07	3.17	2.99	3.37	3.45	3.68	3.90	3.91	3.73	3.27	3.36
Bryce Canyon NP	3.02	2.77	2.23	1.84	1.70	1.38	1.42	1.67	1.67	1.81	2.30	2.75
Cabinet Mountains Wilderness	4.30	3.69	3.23	2.91	2.91	2.87	2.50	2.40	2.84	3.40	4.26	4.37
Caney Creek Wilderness	3.85	3.44	3.14	3.24	3.66	3.71	3.49	3.51	3.73	3.72	3.68	3.88
Canyonlands NP	3.03	2.77	2.17	1.86	1.76	1.40	1.52	1.78	1.81	1.87	2.38	2.77
Cape Romain Wilderness	3.66	3.33	3.24	3.07	3.46	3.88	3.91	4.31	4.30	4.00	3.62	3.73
Capitol Reef NP	3.10	2.86	2.27	1.94	1.81	1.45	1.52	1.77	1.81	1.91	2.43	2.86
Caribou Wilderness	4.17	3.50	3.11	2.68	2.54	2.28	2.21	2.26	2.36	2.60	3.39	3.93
Carlsbad Caverns NP	2.70	2.25	1.75	1.63	1.77	1.70	2.06	2.34	2.59	1.95	2.16	2.57
Chassahowitzka Wilderness	4.31	3.92	3.79	3.62	3.57	4.22	4.26	4.50	4.49	4.29	4.18	4.43
Chiricahua NM	2.29	2.19	1.75	1.34	1.31	1.18	1.94	2.28	1.95	1.64	1.79	2.34
Chiricahua Wilderness	2.25	2.14	1.71	1.30	1.28	1.17	1.95	2.26	1.93	1.61	1.75	2.31
Cohutta Wilderness	3.99	3.59	3.38	3.16	3.76	4.19	4.24	4.37	4.41	4.09	3.77	4.00
Crater Lake NP	5.58	4.73	4.37	4.09	3.70	3.37	3.05	3.08	3.38	4.26	5.52	5.64
Craters of the Moon NM	3.40	3.00	2.52	2.22	2.23	1.94	1.56	1.55	1.76	2.17	3.04	3.32
Cucamonga Wilderness	2.87	2.73	2.68	2.40	2.37	2.29	2.31	2.38	2.43	2.42	2.34	2.54
Denali NP & Pres	3.21	3.19	2.71	2.39	2.46	2.69	3.27	4.05	4.17	3.90	3.59	3.58
Desolation Wilderness	3.77	3.22	2.82	2.26	2.09	1.80	1.67	1.71	1.84	2.08	2.72	3.44
Diamond Peak Wilderness	5.79	4.97	4.61	4.35	3.90	3.55	3.08	3.12	3.55	4.63	5.75	5.88
Dolly Sods Wilderness	3.39	3.16	3.17	2.87	3.63	3.62	3.78	4.06	4.15	3.63	3.27	3.53
Dome Land Wilderness	2.97	2.64	2.51	2.17	2.08	1.91	1.89	1.93	2.01	2.06	2.23	2.56
Eagle Cap Wilderness	5.05	4.28	3.45	3.05	3.02	2.56	2.20	2.15	2.53	3.62	4.89	5.26
Eagles Nest Wilderness	2.48	2.48	2.29	2.32	2.42	2.03	2.02	2.24	2.31	2.09	2.42	2.42
Emigrant Wilderness	3.69	3.25	2.98	2.39	2.21	1.86	1.71	1.73	1.85	2.07	2.68	3.32
Everglades NP	3.14	2.93	2.83	2.67	2.63	3.03	2.91	3.22	3.33	3.12	2.95	3.08
Fitzpatrick Wilderness	2.78	2.60	2.54	2.43	2.44	1.99	1.66	1.63	2.02	2.25	2.77	2.68
Flat Tops Wilderness	2.61	2.53	2.28	2.26	2.31	1.91	1.86	2.04	2.19	2.06	2.42	2.51
Galiuro Wilderness	2.17	1.99	1.68	1.30	1.26	1.14	1.62	1.96	1.75	1.60	1.82	2.31
Gates of the Mountains Wilderness	3.20	2.85	2.71	2.57	2.53	2.50	2.21	2.14	2.37	2.74	3.09	3.12

Table 8. Monthly $f_s(RH)$ – Small $(NH_4)_2SO_4$ and NH_4NO_3 Relative Humidity Adjustment Factor												
Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gearhart Mountain Wilderness	4.80	4.05	3.60	3.30	3.04	2.76	2.37	2.39	2.62	3.36	4.45	4.76
Gila Wilderness	2.40	2.16	1.77	1.45	1.41	1.33	2.11	2.12	2.00	1.73	1.99	2.45
Glacier NP	4.53	3.87	3.63	3.39	3.51	3.48	2.91	2.87	3.47	3.86	4.29	4.37
Glacier Peak Wilderness	5.53	4.98	4.21	3.99	3.90	3.43	3.35	3.54	4.14	5.12	5.80	5.80
Goat Rocks Wilderness	5.81	5.08	4.46	4.23	3.97	3.57	3.35	3.48	4.11	5.22	5.98	6.09
Grand Canyon NP	2.73	2.53	2.12	1.69	1.52	1.27	1.42	1.72	1.69	1.74	2.11	2.49
Grand Teton NP	2.88	2.66	2.48	2.35	2.34	2.00	1.68	1.62	1.94	2.25	2.73	2.82
Great Gulf Wilderness	3.34	3.02	3.12	3.23	3.31	3.46	3.76	4.03	4.22	3.90	3.64	3.50
Great Sand Dunes NP & Pres	2.66	2.55	2.27	2.16	2.22	1.92	2.04	2.47	2.41	2.07	2.57	2.63
Great Smoky Mountains NP	4.01	3.52	3.43	3.14	3.76	4.20	4.21	4.39	4.45	4.05	3.76	3.99
Guadalupe Mountains NP	2.85	2.28	1.74	1.57	1.73	1.69	2.16	2.48	2.74	1.90	2.20	2.71
Haleakala NP	2.98	2.85	2.81	2.72	2.60	2.53	2.65	2.63	2.56	2.69	2.95	2.89
Hawaii Volcanoes NP	3.35	3.10	3.14	3.13	3.14	3.11	3.24	3.42	3.34	3.38	3.76	3.34
Hells Canyon Wilderness	4.28	3.56	2.83	2.42	2.34	2.19	1.80	1.75	2.01	2.75	4.03	4.45
Hercules-Glades Wilderness	3.70	3.33	3.01	3.01	3.47	3.48	3.41	3.51	3.67	3.43	3.46	3.73
Hoover Wilderness	3.63	3.18	2.89	2.33	2.16	1.82	1.66	1.68	1.81	2.02	2.62	3.25
Isle Royale NP	3.26	2.74	2.87	2.58	2.46	3.00	3.59	3.68	3.92	2.88	3.72	3.67
James River Face Wilderness	3.25	3.03	3.02	2.72	3.31	3.48	3.59	3.83	3.91	3.48	3.11	3.38
Jarbidge Wilderness	3.29	2.92	2.31	2.34	2.44	2.22	1.73	1.51	1.48	1.80	2.70	3.13
John Muir Wilderness	3.42	3.02	2.86	2.44	2.29	1.94	1.86	1.87	2.01	2.16	2.60	3.03
Joshua Tree NP	2.62	2.49	2.44	2.19	2.16	2.05	1.97	2.18	2.21	2.19	2.11	2.31
Joyce Kilmer-Slickrock Wilderness	4.02	3.54	3.42	3.15	3.74	4.19	4.21	4.35	4.41	4.04	3.77	4.00
Kaiser Wilderness	3.55	3.13	2.89	2.36	2.21	1.90	1.81	1.83	1.95	2.12	2.59	3.16
Kalmiopsis Wilderness	5.32	4.56	4.30	4.02	3.79	3.54	3.43	3.44	3.56	4.12	5.21	5.28
Kings Canyon	3.35	2.97	2.82	2.42	2.28	1.93	1.85	1.87	2.01	2.15	2.56	2.96
La Garita Wilderness	2.71	2.54	2.21	2.04	2.05	1.72	1.93	2.31	2.26	2.00	2.46	2.62
Lassen Volcanic NP	4.24	3.55	3.16	2.73	2.58	2.31	2.24	2.29	2.39	2.64	3.46	4.00
Lava Beds NM	4.84	4.05	3.63	3.28	3.04	2.76	2.53	2.55	2.75	3.29	4.35	4.75
Linville Gorge Wilderness	3.76	3.46	3.37	3.07	3.74	4.18	4.24	4.62	4.61	4.00	3.59	3.80
Lostwood Wilderness	3.21	3.15	3.36	2.60	2.54	2.86	2.89	2.60	2.53	2.72	3.60	3.52
Lye Brook Wilderness	3.25	2.99	3.10	3.06	3.24	3.30	3.52	3.80	3.95	3.71	3.42	3.35
Mammoth Cave NP	3.86	3.47	3.32	3.54	4.90	5.77	5.58	4.09	4.15	3.73	3.54	3.91
Marble Mountain Wilderness	5.15	4.40	4.15	3.84	3.67	3.44	3.41	3.44	3.50	3.89	4.87	5.04
Maroon Bells-Snowmass Wilderness	2.48	2.44	2.23	2.25	2.25	1.87	2.02	2.35	2.35	2.04	2.36	2.38
Mazatzal Wilderness	2.36	2.20	1.88	1.46	1.36	1.18	1.54	1.89	1.74	1.66	1.91	2.33
Medicine Lake Wilderness	3.25	3.15	3.21	2.52	2.49	2.71	2.71	2.42	2.46	2.65	3.48	3.48
Mesa Verde NP	3.32	2.96	2.55	1.88	1.96	1.46	1.94	2.35	2.13	2.04	2.57	3.06
Mingo Wilderness	3.74	3.38	3.07	2.97	3.39	3.52	3.57	3.64	3.72	3.47	3.43	3.74
Mission Mountains Wilderness	4.03	3.51	3.08	2.82	2.84	2.83	2.49	2.40	2.78	3.28	4.04	4.08
Mokelumne Wilderness	3.75	3.23	2.86	2.29	2.12	1.81	1.68	1.72	1.84	2.08	2.71	3.41
Moosehorn Wilderness	3.59	3.14	3.16	3.44	3.38	3.49	3.98	4.18	4.40	3.94	3.82	3.82
Mount Adams Wilderness	5.71	5.00	4.46	4.23	3.89	3.55	3.26	3.41	4.02	5.13	5.89	5.98
Mount Baldy Wilderness	2.51	2.30	1.92	1.51	1.43	1.25	1.73	2.08	1.88	1.76	2.08	2.54
Mount Hood Wilderness	5.56	4.87	4.40	4.19	3.79	3.44	3.07	3.22	3.79	4.93	5.76	5.81
Mount Jefferson Wilderness	5.95	5.16	4.78	4.57	4.09	3.65	3.10	3.11	3.63	4.91	5.98	6.05

Table 8. Monthly $f_S(RH)$ – Small $(NH_4)_2SO_4$ and NH_4NO_3 Relative Humidity Adjustment Factor												
Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mount Rainier NP	6.01	5.29	4.71	4.51	4.23	3.82	3.59	3.73	4.39	5.55	6.23	6.27
Mount Washington Wilderness	6.35	5.47	5.22	5.07	4.42	3.93	3.16	3.09	3.63	5.07	6.31	6.35
Mount Zirkel Wilderness	2.43	2.44	2.31	2.37	2.51	2.07	1.92	2.02	2.23	2.12	2.41	2.37
Mountain Lakes Wilderness	5.20	4.32	3.90	3.58	3.26	2.96	2.69	2.70	2.94	3.67	4.96	5.24
North Absaroka Wilderness	2.68	2.51	2.50	2.42	2.40	2.13	1.83	1.72	1.98	2.31	2.65	2.65
North Cascades NP	5.37	4.86	4.24	4.04	3.80	3.51	3.34	3.61	4.23	5.08	5.68	5.66
Okefenokee Wilderness	4.16	3.79	3.80	3.65	3.79	4.46	4.24	4.55	4.55	4.35	4.18	4.33
Olympic NP	5.76	5.20	4.81	4.64	3.81	4.04	3.52	4.16	4.70	5.63	6.11	6.02
Otter Creek Wilderness	3.41	3.20	3.20	2.91	3.64	3.70	3.88	4.18	4.26	3.72	3.32	3.56
Pasayten Wilderness	5.46	4.89	4.20	3.96	3.77	3.42	3.28	3.49	4.08	5.00	5.72	5.74
Pecos Wilderness	2.65	2.40	2.10	1.85	1.88	1.65	1.96	2.34	2.27	1.94	2.36	2.60
Petrified Forest NP	2.67	2.43	1.96	1.59	1.46	1.26	1.67	2.06	1.85	1.79	2.20	2.66
Pine Mountain Wilderness	2.44	2.29	1.95	1.51	1.41	1.20	1.54	1.91	1.77	1.70	1.96	2.39
Pinnacles NM	4.02	4.05	4.09	3.01	2.81	2.54	2.40	2.52	2.54	2.74	2.82	3.36
Point Reyes NS	4.16	3.74	3.53	2.96	2.80	2.55	2.69	2.77	2.80	2.90	3.30	3.80
Presidential Range-Dry River Wilderness	3.36	3.02	3.15	3.26	3.37	3.56	3.86	4.14	4.33	3.96	3.68	3.50
Rawah Wilderness	2.31	2.39	2.32	2.44	2.61	2.19	2.05	2.16	2.31	2.12	2.37	2.29
Red Rock Lakes Wilderness	3.09	2.76	2.57	2.41	2.38	2.17	1.86	1.77	2.01	2.39	2.96	3.05
Redwood NP	4.81	4.41	4.51	4.27	4.40	4.37	4.73	4.76	4.46	4.24	4.62	4.45
Rocky Mountain NP	2.09	2.24	2.24	2.45	2.62	2.22	2.09	2.15	2.29	2.04	2.23	2.08
Roosevelt Campobello International Park	3.61	3.14	3.16	3.45	3.37	3.49	3.95	4.15	4.36	3.93	3.84	3.85
Saguaro NP	1.99	1.80	1.56	1.18	1.16	1.07	1.51	1.89	1.66	1.54	1.72	2.25
Saint Marks Wilderness	4.24	3.89	3.79	3.72	3.79	4.32	4.56	4.63	4.43	4.19	4.16	4.39
Salt Creek Wilderness	2.57	2.19	1.75	1.67	1.82	1.69	1.93	2.16	2.37	1.94	2.07	2.38
San Gabriel Wilderness	2.94	2.78	2.72	2.41	2.37	2.29	2.32	2.39	2.44	2.44	2.36	2.58
San Gorgonio Wilderness	2.94	2.94	2.74	2.36	2.34	2.00	1.88	2.02	2.05	2.04	2.10	2.43
San Jacinto Wilderness	2.73	2.65	2.59	2.33	2.30	2.16	2.02	2.26	2.30	2.28	2.19	2.38
San Pedro Parks Wilderness	2.73	2.45	2.10	1.81	1.80	1.55	1.87	2.24	2.16	1.91	2.36	2.65
San Rafael Wilderness	3.38	3.13	3.07	2.68	2.64	2.57	2.66	2.74	2.84	2.77	2.63	2.94
Sawtooth Wilderness	3.78	3.18	2.55	2.20	2.17	1.95	1.51	1.50	1.61	2.11	3.26	3.70
Scapegoat Wilderness	3.70	3.24	2.97	2.79	2.78	2.75	2.41	2.31	2.65	3.09	3.67	3.68
Selway-Bitterroot Wilderness	3.99	3.41	2.90	2.56	2.54	2.43	2.00	1.93	2.21	2.82	3.78	4.01
Seney Wilderness	3.69	3.10	3.30	3.10	3.03	3.45	3.80	4.27	4.31	3.82	3.97	3.87
Sequoia NP	3.25	2.91	2.87	2.59	2.46	1.97	1.85	1.84	2.02	2.18	2.64	2.85
Shenandoah NP	3.26	2.99	3.02	2.72	3.28	3.46	3.59	3.85	3.91	3.41	3.08	3.44
Shining Rock Wilderness	3.89	3.51	3.37	3.11	3.77	4.22	4.29	4.58	4.60	4.12	3.69	3.88
Sierra Ancha Wilderness	2.38	2.21	1.87	1.46	1.36	1.19	1.60	1.95	1.78	1.69	1.96	2.41
Simeonof Wilderness	4.86	4.88	4.44	4.64	4.92	5.46	6.08	6.35	5.30	4.29	4.52	4.98
Sipsey Wilderness	3.89	3.52	3.23	3.13	3.60	3.99	4.13	4.09	4.12	3.87	3.61	3.89
South Warner Wilderness	4.36	3.67	3.20	2.81	2.64	2.39	2.04	2.07	2.24	2.76	3.71	4.20
Strawberry Mountain Wilderness	5.26	4.45	3.71	3.32	3.18	2.70	2.26	2.24	2.66	3.84	5.11	5.44
Superstition Wilderness	2.25	2.06	1.77	1.38	1.29	1.15	1.52	1.81	1.66	1.58	1.83	2.28
Swanquarter Wilderness	3.31	3.09	3.01	2.78	3.09	3.39	3.57	3.68	3.55	3.40	3.14	3.33
Sycamore Canyon Wilderness	2.52	2.41	2.05	1.59	1.47	1.23	1.53	1.98	1.85	1.77	2.03	2.45
Teton Wilderness	2.78	2.59	2.49	2.37	2.36	2.06	1.75	1.67	1.96	2.28	2.70	2.73

Table 8. Monthly $f_S(RH)$ – Small $(NH_4)_2SO_4$ and NH_4NO_3 Relative Humidity Adjustment Factor												
Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Theodore Roosevelt NP	3.17	3.11	3.22	2.71	2.74	2.85	2.73	2.49	2.48	2.66	3.42	3.37
Thousand Lakes Wilderness	4.34	3.60	3.22	2.79	2.62	2.34	2.26	2.31	2.41	2.69	3.58	4.11
Three Sisters Wilderness	6.22	5.38	5.09	4.92	4.35	3.89	3.21	3.17	3.68	5.02	6.20	6.24
Tuxedni Wilderness	4.11	3.89	3.26	3.14	3.11	3.31	4.13	4.57	4.57	4.04	4.04	4.23
UL Bend Wilderness	2.94	2.75	2.77	2.55	2.44	2.41	2.19	1.97	2.12	2.50	2.96	2.95
Upper Buffalo Wilderness	3.73	3.33	3.03	3.07	3.54	3.57	3.43	3.50	3.71	3.51	3.52	3.74
Ventana Wilderness	3.92	3.69	3.61	2.86	2.69	2.46	2.46	2.55	2.61	2.72	2.89	3.43
Virgin Islands NP	2.41	2.36	2.27	2.39	2.44	2.40	2.43	2.57	2.58	2.63	2.68	2.54
Voyageurs NP	3.16	2.77	2.82	2.59	2.65	3.28	3.25	3.48	3.66	3.02	3.37	3.32
Washakie Wilderness	2.68	2.52	2.49	2.40	2.40	2.09	1.77	1.68	1.98	2.29	2.66	2.65
Weminuche Wilderness	2.80	2.58	2.22	1.97	1.97	1.64	1.89	2.28	2.20	1.97	2.45	2.69
West Elk Wilderness	2.64	2.53	2.24	2.15	2.16	1.79	1.92	2.24	2.26	2.02	2.41	2.53
Wheeler Peak Wilderness	2.72	2.50	2.17	1.97	2.02	1.76	1.98	2.42	2.36	2.01	2.48	2.66
White Mountain Wilderness	2.54	2.19	1.76	1.58	1.65	1.53	1.94	2.20	2.29	1.87	2.07	2.45
Wichita Mountains Wilderness	3.17	2.94	2.69	2.68	3.15	2.86	2.49	2.70	3.07	2.87	2.97	3.20
Wind Cave NP	2.81	2.81	2.86	2.82	3.06	2.81	2.50	2.46	2.44	2.52	2.97	2.83
Wolf Island Wilderness	4.02	3.68	3.58	3.45	3.59	4.17	4.13	4.47	4.46	4.23	4.05	4.18
Yellowstone NP	2.82	2.61	2.53	2.42	2.41	2.16	1.86	1.76	2.02	2.36	2.78	2.80
Yolla Bolly-Middle Eel Wilderness	4.48	3.82	3.53	3.13	3.00	2.75	2.81	2.87	2.93	3.11	3.84	4.24
Yosemite NP	3.62	3.32	3.13	2.52	2.34	1.89	1.69	1.67	1.78	2.04	2.65	3.22
Zion NP	3.05	2.81	2.26	1.84	1.67	1.37	1.33	1.54	1.58	1.75	2.25	2.72

Table 9. Monthly $f_{ss}(RH)$ – Sea Salt Relative Humidity Adjustment Factor												
Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Acadia NP	3.90	3.48	3.40	3.66	3.71	3.81	4.19	4.27	4.44	4.13	4.10	4.19
Agua Tibia Wilderness	2.94	2.95	3.02	2.85	2.88	2.81	2.78	2.90	2.90	2.83	2.56	2.69
Alpine Lakes Wilderness	5.35	4.96	4.27	4.11	4.18	3.64	3.68	3.73	4.12	4.98	5.51	5.53
Anaconda Pintler Wilderness	4.00	3.56	3.18	2.90	2.85	2.75	2.33	2.25	2.52	3.10	3.81	3.97
Ansel Adams Wilderness	3.55	3.25	3.04	2.54	2.38	2.05	1.91	1.91	2.03	2.21	2.72	3.21
Arches NP	3.25	2.99	2.26	1.97	1.86	1.48	1.59	1.82	1.88	1.96	2.60	3.02
Badlands NP	3.37	3.33	3.27	3.05	3.25	3.15	2.89	2.81	2.74	2.82	3.41	3.38
Bandelier NM	2.91	2.59	2.22	1.87	1.90	1.67	2.11	2.54	2.37	2.00	2.49	2.78
Bering Sea Wilderness	4.39	4.57	4.60	4.58	4.57	4.70	5.26	5.73	5.11	4.59	4.52	4.54
Big Bend NP	2.20	2.03	1.75	1.67	1.84	1.87	2.03	2.34	2.47	2.09	2.10	2.22
Black Canyon of the Gunnison NP	3.05	2.89	2.47	2.31	2.28	1.89	2.04	2.36	2.37	2.18	2.71	2.92
Bob Marshall Wilderness	4.08	3.66	3.35	3.11	3.08	3.04	2.68	2.59	2.94	3.42	3.98	4.05
Bosque del Apache Wilderness	2.77	2.43	1.95	1.62	1.62	1.47	2.06	2.40	2.29	1.92	2.27	2.71
Boundary Waters Canoe Area Wilderness	3.73	3.35	3.29	2.91	3.00	3.44	3.68	3.88	3.98	3.45	3.89	3.91
Breton Wilderness	4.10	3.89	3.87	3.85	4.02	4.21	4.44	4.38	4.23	3.99	4.01	4.11
Bridger Wilderness	3.25	3.05	2.90	2.67	2.62	2.17	1.81	1.79	2.17	2.43	3.15	3.17
Brigantine Wilderness	3.53	3.24	3.30	3.15	3.49	3.63	3.84	4.02	4.02	3.82	3.48	3.55
Bryce Canyon NP	3.24	3.00	2.40	1.96	1.80	1.45	1.52	1.80	1.78	1.93	2.52	2.99
Cabinet Mountains Wilderness	4.42	3.93	3.50	3.18	3.13	3.06	2.67	2.59	3.01	3.58	4.33	4.46
Caney Creek Wilderness	3.90	3.52	3.31	3.41	3.83	3.88	3.69	3.68	3.82	3.76	3.77	3.93
Canyonlands NP	3.30	3.04	2.33	1.99	1.87	1.48	1.63	1.90	1.94	2.00	2.64	3.07
Cape Romain Wilderness	3.74	3.44	3.37	3.23	3.62	3.99	4.04	4.32	4.29	4.03	3.74	3.81
Capitol Reef NP	3.35	3.11	2.45	2.08	1.93	1.54	1.62	1.90	1.94	2.05	2.68	3.13
Caribou Wilderness	4.16	3.63	3.28	2.89	2.75	2.47	2.33	2.37	2.49	2.74	3.48	3.97
Carlsbad Caverns NP	2.75	2.36	1.86	1.72	1.89	1.86	2.27	2.59	2.75	2.09	2.29	2.68
Chassahowitzka Wilderness	4.29	3.99	3.89	3.76	3.77	4.29	4.34	4.51	4.49	4.33	4.23	4.38
Chiricahua NM	2.53	2.38	1.91	1.41	1.38	1.21	2.12	2.55	2.18	1.78	1.99	2.56
Chiricahua Wilderness	2.48	2.33	1.86	1.37	1.35	1.20	2.12	2.54	2.16	1.75	1.94	2.52
Cohutta Wilderness	3.97	3.62	3.44	3.26	3.82	4.20	4.24	4.35	4.35	4.05	3.82	4.02
Crater Lake NP	5.15	4.56	4.31	4.12	3.80	3.52	3.20	3.23	3.44	4.17	5.10	5.19
Craters of the Moon NM	3.78	3.41	2.86	2.51	2.48	2.16	1.72	1.69	1.93	2.43	3.38	3.72
Cucamonga Wilderness	3.07	3.01	3.03	2.79	2.80	2.72	2.72	2.80	2.81	2.76	2.58	2.77
Denali NP & Pres	3.68	3.57	3.07	2.74	2.74	3.01	3.53	4.13	4.19	4.09	3.92	3.94
Desolation Wilderness	3.85	3.39	3.02	2.48	2.32	2.01	1.84	1.87	2.02	2.28	2.94	3.58
Diamond Peak Wilderness	5.29	4.72	4.45	4.27	3.92	3.65	3.23	3.26	3.56	4.43	5.26	5.34
Dolly Sods Wilderness	3.60	3.35	3.31	3.03	3.66	3.76	3.91	4.12	4.16	3.72	3.47	3.72
Dome Land Wilderness	3.10	2.86	2.75	2.42	2.33	2.15	2.11	2.16	2.22	2.26	2.40	2.71
Eagle Cap Wilderness	4.84	4.27	3.57	3.22	3.14	2.74	2.33	2.27	2.60	3.61	4.68	4.99
Eagles Nest Wilderness	2.86	2.82	2.54	2.52	2.57	2.20	2.20	2.44	2.46	2.27	2.73	2.79
Emigrant Wilderness	3.70	3.37	3.13	2.60	2.42	2.05	1.88	1.88	2.01	2.24	2.84	3.39
Everglades NP	3.60	3.44	3.37	3.22	3.21	3.58	3.50	3.72	3.78	3.61	3.50	3.55
Fitzpatrick Wilderness	3.25	3.05	2.88	2.66	2.62	2.18	1.82	1.79	2.16	2.43	3.13	3.18
Flat Tops Wilderness	2.99	2.88	2.54	2.47	2.47	2.07	2.03	2.23	2.35	2.25	2.75	2.89
Galiuro Wilderness	2.42	2.19	1.82	1.35	1.31	1.16	1.76	2.18	1.94	1.73	2.00	2.52
Gates of the Mountains Wilderness	3.62	3.27	3.05	2.85	2.80	2.74	2.43	2.35	2.58	2.99	3.41	3.52

Table 9. Monthly $f_{ss}(RH)$ – Sea Salt Relative Humidity Adjustment Factor												
Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gearhart Mountain Wilderness	4.63	4.06	3.67	3.40	3.16	2.90	2.49	2.50	2.70	3.39	4.31	4.60
Gila Wilderness	2.63	2.35	1.91	1.52	1.48	1.36	2.22	2.36	2.19	1.87	2.17	2.65
Glacier NP	4.61	4.12	3.87	3.64	3.63	3.59	3.11	3.11	3.63	4.03	4.43	4.51
Glacier Peak Wilderness	5.14	4.73	4.19	4.03	3.93	3.60	3.51	3.63	4.04	4.79	5.31	5.34
Goat Rocks Wilderness	5.30	4.79	4.32	4.15	3.94	3.65	3.46	3.55	3.99	4.83	5.40	5.51
Grand Canyon NP	2.93	2.73	2.26	1.78	1.61	1.32	1.50	1.85	1.79	1.84	2.29	2.70
Grand Teton NP	3.34	3.10	2.82	2.59	2.56	2.21	1.85	1.78	2.12	2.48	3.10	3.29
Great Gulf Wilderness	3.60	3.29	3.29	3.34	3.41	3.58	3.85	4.07	4.20	3.96	3.81	3.73
Great Sand Dunes NP & Pres	2.98	2.84	2.48	2.33	2.36	2.08	2.24	2.66	2.56	2.26	2.82	2.94
Great Smoky Mountains NP	4.01	3.57	3.47	3.22	3.82	4.23	4.24	4.37	4.38	4.03	3.81	4.02
Guadalupe Mountains NP	2.82	2.35	1.84	1.64	1.82	1.83	2.36	2.72	2.85	2.01	2.28	2.76
Haleakala NP	3.52	3.43	3.40	3.35	3.25	3.18	3.29	3.27	3.22	3.33	3.52	3.47
Hawaii Volcanoes NP	3.80	3.68	3.71	3.72	3.72	3.69	3.79	3.83	3.79	3.83	4.08	3.80
Hells Canyon Wilderness	4.39	3.81	3.15	2.75	2.63	2.44	1.97	1.90	2.19	3.00	4.13	4.51
Hercules-Glades Wilderness	3.86	3.51	3.23	3.22	3.66	3.72	3.69	3.73	3.81	3.57	3.65	3.88
Hoover Wilderness	3.66	3.31	3.05	2.53	2.36	2.00	1.82	1.82	1.96	2.18	2.79	3.34
Isle Royale NP	3.78	3.34	3.28	2.93	2.78	3.31	3.83	3.87	4.06	3.40	4.05	4.04
James River Face Wilderness	3.43	3.19	3.16	2.90	3.46	3.69	3.79	3.97	4.00	3.61	3.31	3.56
Jarbidge Wilderness	3.65	3.28	2.62	2.69	2.71	2.44	1.95	1.67	1.60	2.01	3.03	3.51
John Muir Wilderness	3.46	3.18	3.07	2.68	2.51	2.17	2.06	2.08	2.20	2.35	2.75	3.12
Joshua Tree NP	2.83	2.76	2.75	2.52	2.53	2.41	2.28	2.53	2.53	2.48	2.32	2.54
Joyce Kilmer-Slickrock Wilderness	4.01	3.58	3.46	3.24	3.81	4.22	4.23	4.35	4.35	4.03	3.82	4.02
Kaiser Wilderness	3.58	3.27	3.08	2.58	2.42	2.10	1.99	2.00	2.12	2.29	2.75	3.24
Kalmiopsis Wilderness	4.98	4.45	4.28	4.09	3.89	3.66	3.49	3.51	3.60	4.08	4.90	4.96
Kings Canyon	3.40	3.13	3.03	2.66	2.50	2.16	2.05	2.07	2.20	2.33	2.71	3.05
La Garita Wilderness	3.03	2.83	2.41	2.21	2.19	1.86	2.10	2.50	2.42	2.16	2.72	2.93
Lassen Volcanic NP	4.21	3.66	3.33	2.93	2.78	2.50	2.36	2.40	2.51	2.78	3.54	4.02
Lava Beds NM	4.64	4.04	3.68	3.37	3.15	2.89	2.62	2.65	2.82	3.32	4.21	4.56
Linville Gorge Wilderness	3.80	3.52	3.43	3.18	3.80	4.20	4.25	4.51	4.48	3.97	3.67	3.86
Lostwood Wilderness	3.77	3.66	3.67	2.86	2.79	3.07	3.11	2.82	2.80	2.99	3.93	3.95
Lye Brook Wilderness	3.53	3.26	3.27	3.20	3.36	3.48	3.70	3.93	4.04	3.82	3.63	3.61
Mammoth Cave NP	3.99	3.63	3.45	3.50	4.52	5.19	5.08	4.16	4.17	3.81	3.73	4.03
Marble Mountain Wilderness	4.85	4.32	4.16	3.92	3.76	3.53	3.44	3.46	3.51	3.86	4.63	4.78
Maroon Bells-Snowmass Wilderness	2.89	2.82	2.52	2.49	2.45	2.04	2.22	2.57	2.54	2.26	2.71	2.80
Mazatzal Wilderness	2.60	2.40	2.03	1.53	1.42	1.21	1.66	2.06	1.90	1.77	2.10	2.55
Medicine Lake Wilderness	3.79	3.66	3.56	2.80	2.75	2.94	2.93	2.66	2.73	2.95	3.85	3.92
Mesa Verde NP	3.40	3.10	2.61	1.95	2.00	1.53	2.04	2.45	2.28	2.05	2.69	3.15
Mingo Wilderness	3.92	3.58	3.30	3.19	3.58	3.72	3.80	3.82	3.85	3.61	3.66	3.90
Mission Mountains Wilderness	4.24	3.79	3.38	3.10	3.08	3.04	2.68	2.59	2.96	3.48	4.17	4.26
Mokelumne Wilderness	3.81	3.38	3.04	2.51	2.34	2.02	1.86	1.88	2.02	2.27	2.91	3.52
Moosehorn Wilderness	3.80	3.42	3.32	3.50	3.47	3.60	3.98	4.15	4.31	4.02	3.97	3.99
Mount Adams Wilderness	5.24	4.74	4.34	4.18	3.91	3.66	3.41	3.51	3.93	4.78	5.36	5.44
Mount Baldy Wilderness	2.74	2.50	2.05	1.58	1.50	1.29	1.87	2.28	2.06	1.87	2.26	2.74
Mount Hood Wilderness	5.16	4.67	4.33	4.18	3.87	3.61	3.29	3.38	3.78	4.67	5.29	5.33
Mount Jefferson Wilderness	5.38	4.84	4.55	4.42	4.05	3.74	3.27	3.28	3.63	4.64	5.41	5.46
Mount Rainier NP	5.42	4.92	4.50	4.36	4.13	3.86	3.67	3.76	4.20	5.05	5.56	5.62

Table 9. Monthly $f_{ss}(RH)$ – Sea Salt Relative Humidity Adjustment Factor												
Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mount Washington Wilderness	5.61	5.03	4.81	4.71	4.24	3.91	3.31	3.25	3.60	4.73	5.59	5.62
Mount Zirkel Wilderness	2.85	2.83	2.61	2.61	2.67	2.24	2.10	2.23	2.38	2.31	2.75	2.78
Mountain Lakes Wilderness	4.89	4.26	3.93	3.67	3.40	3.11	2.82	2.83	3.04	3.67	4.68	4.91
North Absaroka Wilderness	3.18	2.97	2.83	2.66	2.64	2.35	2.02	1.89	2.16	2.53	3.03	3.13
North Cascades NP	5.03	4.65	4.22	4.08	3.88	3.68	3.53	3.70	4.13	4.78	5.24	5.25
Okefenokee Wilderness	4.13	3.83	3.82	3.69	3.85	4.38	4.28	4.51	4.48	4.31	4.18	4.27
Olympic NP	5.27	4.87	4.61	4.51	3.94	4.12	3.76	4.16	4.51	5.17	5.51	5.46
Otter Creek Wilderness	3.63	3.40	3.34	3.06	3.67	3.82	3.98	4.19	4.23	3.78	3.51	3.76
Pasayten Wilderness	5.09	4.67	4.18	4.00	3.84	3.58	3.45	3.58	3.99	4.71	5.25	5.30
Pecos Wilderness	2.91	2.64	2.25	1.97	2.00	1.78	2.15	2.57	2.44	2.09	2.56	2.83
Petrified Forest NP	2.93	2.66	2.11	1.66	1.53	1.30	1.81	2.26	2.03	1.91	2.40	2.88
Pine Mountain Wilderness	2.69	2.50	2.11	1.60	1.47	1.24	1.67	2.09	1.92	1.82	2.16	2.62
Pinnacles NM	3.94	3.97	3.99	3.12	2.94	2.67	2.54	2.63	2.65	2.80	2.96	3.36
Point Reyes NS	4.20	3.88	3.72	3.25	3.12	2.88	2.96	3.01	3.05	3.12	3.48	3.90
Presidential Range-Dry River Wilderness	3.60	3.28	3.31	3.36	3.45	3.66	3.92	4.14	4.27	3.99	3.83	3.72
Rawah Wilderness	2.70	2.74	2.58	2.65	2.76	2.36	2.23	2.37	2.45	2.31	2.69	2.66
Red Rock Lakes Wilderness	3.51	3.18	2.91	2.67	2.63	2.41	2.06	1.94	2.20	2.63	3.29	3.46
Redwood NP	4.66	4.38	4.48	4.34	4.41	4.35	4.56	4.59	4.34	4.19	4.51	4.44
Rocky Mountain NP	2.44	2.56	2.47	2.64	2.75	2.37	2.26	2.36	2.41	2.20	2.51	2.41
Roosevelt Campobello International Park	3.82	3.43	3.32	3.52	3.47	3.61	3.96	4.13	4.29	4.02	3.99	4.01
Saguaro NP	2.24	2.00	1.69	1.21	1.20	1.08	1.67	2.13	1.86	1.65	1.89	2.44
Saint Marks Wilderness	4.18	3.89	3.82	3.76	3.85	4.30	4.49	4.54	4.39	4.19	4.15	4.30
Salt Creek Wilderness	2.72	2.37	1.88	1.77	1.96	1.87	2.15	2.44	2.59	2.12	2.26	2.56
San Gabriel Wilderness	3.12	3.04	3.04	2.77	2.78	2.69	2.69	2.77	2.79	2.74	2.59	2.79
San Gorgonio Wilderness	2.97	3.06	2.93	2.60	2.63	2.28	2.13	2.30	2.31	2.24	2.25	2.55
San Jacinto Wilderness	2.92	2.91	2.91	2.67	2.69	2.55	2.33	2.64	2.64	2.57	2.40	2.60
San Pedro Parks Wilderness	3.00	2.71	2.25	1.94	1.91	1.66	2.04	2.45	2.33	2.05	2.57	2.88
San Rafael Wilderness	3.49	3.35	3.34	3.00	2.99	2.90	2.97	3.04	3.09	3.00	2.86	3.12
Sawtooth Wilderness	4.05	3.53	2.89	2.53	2.44	2.18	1.66	1.61	1.76	2.38	3.55	4.00
Scapegoat Wilderness	3.97	3.57	3.27	3.04	3.01	2.96	2.60	2.51	2.83	3.30	3.86	3.93
Selway-Bitterroot Wilderness	4.20	3.71	3.21	2.86	2.80	2.66	2.18	2.09	2.39	3.06	3.96	4.20
Seney Wilderness	4.05	3.60	3.60	3.30	3.20	3.58	3.91	4.28	4.30	4.00	4.19	4.16
Sequoia NP	3.27	3.07	3.10	2.84	2.66	2.21	2.06	2.05	2.21	2.35	2.75	2.93
Shenandoah NP	3.44	3.17	3.17	2.90	3.42	3.66	3.78	3.97	3.98	3.56	3.28	3.62
Shining Rock Wilderness	3.90	3.55	3.43	3.21	3.82	4.22	4.28	4.48	4.48	4.06	3.76	3.92
Sierra Ancha Wilderness	2.62	2.42	2.02	1.53	1.42	1.22	1.73	2.14	1.95	1.81	2.15	2.62
Simeonof Wilderness	4.83	4.85	4.54	4.68	4.83	5.20	5.57	5.72	5.11	4.48	4.62	4.89
Sipsey Wilderness	3.94	3.60	3.36	3.28	3.72	4.06	4.18	4.14	4.13	3.91	3.74	3.96
South Warner Wilderness	4.32	3.75	3.31	2.94	2.77	2.51	2.13	2.15	2.31	2.83	3.71	4.19
Strawberry Mountain Wilderness	4.97	4.37	3.77	3.44	3.28	2.88	2.41	2.38	2.73	3.77	4.82	5.10
Superstition Wilderness	2.49	2.27	1.92	1.44	1.34	1.17	1.64	1.98	1.82	1.69	2.01	2.49
Swanquarter Wilderness	3.52	3.30	3.25	3.09	3.42	3.71	3.88	3.96	3.83	3.67	3.43	3.55
Sycamore Canyon Wilderness	2.78	2.62	2.22	1.68	1.55	1.27	1.67	2.17	2.00	1.90	2.25	2.69
Teton Wilderness	3.26	3.04	2.83	2.61	2.59	2.27	1.93	1.83	2.14	2.50	3.07	3.21
Theodore Roosevelt NP	3.67	3.56	3.51	2.93	2.97	3.09	2.96	2.72	2.72	2.93	3.75	3.78

Table 9. Monthly $f_{ss}(RH)$ – Sea Salt Relative Humidity Adjustment Factor												
Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Thousand Lakes Wilderness	4.27	3.70	3.38	2.99	2.82	2.52	2.37	2.42	2.53	2.82	3.62	4.08
Three Sisters Wilderness	5.53	4.97	4.74	4.63	4.20	3.89	3.35	3.31	3.65	4.70	5.53	5.56
Tuxedni Wilderness	4.28	4.06	3.53	3.46	3.44	3.64	4.26	4.56	4.51	4.17	4.17	4.37
UL Bend Wilderness	3.44	3.22	3.12	2.79	2.70	2.67	2.42	2.18	2.35	2.77	3.34	3.40
Upper Buffalo Wilderness	3.85	3.47	3.23	3.27	3.72	3.78	3.69	3.70	3.84	3.64	3.67	3.86
Ventana Wilderness	3.91	3.76	3.70	3.08	2.93	2.69	2.69	2.75	2.80	2.87	3.06	3.48
Virgin Islands NP	3.17	3.12	3.04	3.15	3.19	3.17	3.18	3.31	3.30	3.36	3.39	3.28
Voyageurs NP	3.69	3.31	3.20	2.90	2.89	3.46	3.55	3.71	3.87	3.42	3.83	3.80
Washakie Wilderness	3.18	2.98	2.83	2.64	2.62	2.31	1.96	1.85	2.15	2.50	3.04	3.14
Weminuche Wilderness	3.08	2.85	2.39	2.11	2.09	1.77	2.05	2.46	2.36	2.12	2.69	2.95
West Elk Wilderness	3.00	2.87	2.49	2.36	2.33	1.94	2.10	2.44	2.43	2.20	2.72	2.89
Wheeler Peak Wilderness	3.00	2.76	2.35	2.11	2.15	1.92	2.17	2.63	2.52	2.18	2.71	2.93
White Mountain Wilderness	2.71	2.37	1.89	1.68	1.76	1.66	2.14	2.46	2.49	2.02	2.25	2.63
Wichita Mountains Wilderness	3.35	3.12	2.91	2.94	3.40	3.21	2.84	3.01	3.32	3.10	3.20	3.40
Wind Cave NP	3.25	3.20	3.13	3.01	3.22	3.06	2.75	2.68	2.63	2.75	3.28	3.24
Wolf Island Wilderness	4.03	3.74	3.66	3.55	3.72	4.20	4.20	4.46	4.42	4.22	4.08	4.15
Yellowstone NP	3.29	3.05	2.87	2.66	2.65	2.39	2.05	1.93	2.21	2.59	3.14	3.25
Yolla Bolly-Middle Eel Wilderness	4.38	3.89	3.66	3.31	3.18	2.92	2.89	2.94	3.00	3.20	3.84	4.19
Yosemite NP	3.58	3.38	3.23	2.71	2.54	2.08	1.84	1.79	1.93	2.18	2.78	3.25
Zion NP	3.26	3.03	2.44	1.96	1.78	1.44	1.41	1.66	1.67	1.88	2.48	2.98

Table 10. Monthly Average Natural Conditions Visual Range In Kilometers												
Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Acadia NP	173	177	177	174	174	173	170	169	167	171	171	170
Agua Tibia Wilderness	226	227	226	228	228	229	229	228	228	228	230	229
Alpine Lakes Wilderness	224	228	236	238	236	243	242	242	237	227	222	222
Anaconda Pintler Wilderness	256	259	262	267	268	271	273	272	271	269	265	259
Ansel Adams Wilderness	258	263	266	269	269	270	274	275	272	267	259	258
Arches NP	265	268	274	276	277	281	280	278	277	276	271	268
Badlands NP	233	233	233	234	232	233	235	236	236	236	232	233
Bandelier NM	269	272	276	280	281	283	278	274	276	277	274	269
Bering Sea Wilderness												
Big Bend NP	236	234	233	234	233	231	225	220	227	233	235	235
Black Canyon of the Gunnison NP	278	280	282	283	282	282	281	278	276	280	280	278
Bob Marshall Wilderness	257	259	262	263	263	266	265	262	262	264	260	258
Bosque del Apache Wilderness	249	252	256	259	259	260	255	252	253	256	253	249
Boundary Waters Canoe Area Wilderness	184	187	189	190	190	191	193	194	191	188	184	184
Breton Wilderness	173	176	176	179	177	174	172	170	169	174	171	171
Bridger Wilderness	278	280	286	290	292	296	295	292	292	291	285	280
Brigantine Wilderness	159	161	161	161	160	158	156	157	158	160	160	159
Bryce Canyon NP	268	269	270	271	271	275	279	279	275	273	268	268
Cabinet Mountains Wilderness	252	254	253	255	251	251	249	247	247	248	252	251
Caney Creek Wilderness	174	177	180	183	183	183	186	186	183	179	174	173
Canyonlands NP	257	261	264	263	259	259	260	260	258	258	259	257
Cape Romain Wilderness	167	169	174	177	178	181	180	178	177	177	172	169
Capitol Reef NP	269	271	277	280	281	285	284	281	281	280	275	271
Caribou Wilderness	250	256	259	263	264	267	267	267	266	264	257	252
Carlsbad Caverns NP	266	271	276	277	275	276	272	270	267	274	271	267
Chassahowitzka Wilderness	171	173	174	175	175	171	171	169	169	171	171	170
Chiricahua NM	253	254	258	261	262	263	256	253	256	259	257	252
Chiricahua Wilderness	253	254	258	262	262	263	256	253	256	259	258	252
Cohutta Wilderness	181	184	185	187	183	180	180	179	179	181	183	181
Crater Lake NP	255	263	266	269	273	276	280	279	276	267	256	255
Craters of the Moon NM	245	248	252	255	255	257	261	261	259	255	248	246
Cucamonga Wilderness	263	264	264	267	267	268	268	267	267	267	268	266
Denali NP & Pres	257	257	261	263	263	261	257	251	250	252	254	254
Desolation Wilderness	270	275	279	285	287	290	292	292	290	287	280	273
Diamond Peak Wilderness	253	261	264	267	271	275	279	279	275	264	254	253
Dolly Sods Wilderness	197	200	201	203	204	206	206	205	205	204	203	200
Dome Land Wilderness	242	244	244	247	241	241	239	237	236	241	243	241
Eagle Cap Wilderness	229	234	241	245	245	249	252	253	249	240	230	227
Eagles Nest Wilderness	302	302	304	304	303	308	308	305	304	307	303	303
Emigrant Wilderness	242	245	248	253	254	258	259	259	258	256	250	245
Everglades NP	168	170	171	172	172	169	170	167	166	168	169	168
Fitzpatrick Wilderness	280	282	283	284	284	289	292	293	288	286	280	281
Flat Tops Wilderness	301	302	305	305	304	309	310	307	306	307	303	302
Galiuro Wilderness	254	255	258	262	262	263	259	256	258	259	257	252
Gates of the Mountains Wilderness	281	285	287	288	289	289	292	293	291	286	283	282

Table 10. Monthly Average Natural Conditions Visual Range In Kilometers												
Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gearhart Mountain Wilderness	262	269	274	277	280	283	287	287	285	277	266	263
Gila Wilderness	275	278	282	285	285	286	278	278	279	282	279	275
Glacier NP	224	228	230	231	231	231	235	235	231	228	225	225
Glacier Peak Wilderness	233	237	243	245	245	249	250	248	244	236	231	231
Goat Rocks Wilderness	243	249	254	256	259	263	265	263	258	248	241	241
Grand Canyon NP	267	269	273	278	280	282	281	277	278	277	273	269
Grand Teton NP	274	278	277	276	275	273	270	268	266	269	272	273
Great Gulf Wilderness	192	192	195	195	195	197	196	193	193	196	192	192
Great Sand Dunes NP & Pres	255	260	260	263	257	254	253	252	251	255	257	255
Great Smoky Mountains NP	184	185	187	188	188	190	192	193	190	188	185	184
Guadalupe Mountains NP	265	270	276	278	276	276	271	268	266	274	271	266
Haleakala NP	232	234	234	235	237	238	236	236	237	235	232	233
Hawaii Volcanoes NP	243	246	246	246	246	246	244	243	244	243	238	243
Hells Canyon Wilderness	224	229	234	237	238	239	242	243	241	235	226	223
Hercules-Glades Wilderness	178	180	182	182	179	179	180	179	178	180	179	178
Hoover Wilderness	259	263	265	271	273	276	278	277	276	274	268	262
Isle Royale NP	182	185	184	186	187	183	179	179	177	184	179	179
James River Face Wilderness	181	183	187	187	186	188	192	193	193	191	185	182
Jarbidge Wilderness	245	246	246	249	244	243	242	240	239	243	246	243
John Muir Wilderness	256	260	261	264	258	254	254	253	252	255	258	256
Joshua Tree NP	242	246	247	251	252	255	256	256	255	253	249	246
Joyce Kilmer-Slickrock Wilderness	186	187	187	189	189	190	190	189	188	189	189	188
Kaiser Wilderness	260	264	266	272	273	277	278	278	276	274	269	264
Kalmiopsis Wilderness	194	200	202	205	207	209	211	210	209	204	195	195
Kings Canyon	229	232	233	236	237	240	240	240	239	238	235	232
La Garita Wilderness	252	259	263	266	268	271	273	273	271	266	256	253
Lassen Volcanic NP	263	264	267	269	269	272	270	266	267	269	265	263
Lava Beds NM	244	250	253	257	258	261	261	261	260	258	251	246
Linville Gorge Wilderness	180	182	183	185	180	177	177	175	175	178	181	180
Lostwood Wilderness	229	230	228	234	235	232	232	234	235	233	227	227
Lye Brook Wilderness	196	198	197	197	196	195	194	192	191	192	195	195
Mammoth Cave NP	187	188	189	189	189	192	191	188	188	191	188	188
Marble Mountain Wilderness	251	255	256	254	242	235	237	249	248	252	254	250
Maroon Bells-Snowmass Wilderness	274	281	284	287	289	291	292	291	291	286	276	275
Mazatzal Wilderness	252	253	256	260	261	263	259	256	258	258	256	252
Medicine Lake Wilderness	231	232	231	236	237	235	235	237	237	236	230	229
Mesa Verde NP	264	267	271	277	276	281	276	272	275	275	270	266
Mingo Wilderness	166	169	172	174	173	173	176	176	174	171	166	166
Mission Mountains Wilderness	249	252	254	255	251	250	250	249	249	251	251	249
Mokelumne Wilderness	252	259	263	266	269	272	275	273	268	257	251	250
Moosehorn Wilderness	159	163	166	167	170	172	174	173	170	162	158	157
Mount Adams Wilderness	242	248	251	253	258	262	267	267	262	250	241	241
Mount Baldy Wilderness	261	266	269	275	276	280	281	281	279	277	271	264
Mount Hood Wilderness	241	249	253	256	259	262	265	265	262	255	243	241
Mount Jefferson Wilderness	237	240	240	238	239	238	234	232	230	234	235	235

Table 10. Monthly Average Natural Conditions Visual Range In Kilometers												
Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mount Rainier NP	215	220	224	226	228	231	233	232	227	218	213	213
Mount Washington Wilderness	216	223	224	225	230	234	240	241	237	225	217	216
Mount Zirkel Wilderness	296	296	297	296	295	300	301	300	298	299	296	296
Mountain Lakes Wilderness	284	285	286	287	287	290	294	295	292	288	284	284
North Absaroka Wilderness	246	251	256	258	260	262	264	261	256	249	244	244
North Cascades NP	243	246	246	247	246	241	243	240	240	242	243	242
Okefenokee Wilderness	162	166	168	169	174	173	176	172	169	163	160	161
Olympic NP	233	235	235	238	231	230	228	226	225	230	234	231
Otter Creek Wilderness	180	183	188	190	191	194	195	193	189	183	178	178
Pasayten Wilderness	269	271	274	277	276	279	276	272	272	276	272	269
Pecos Wilderness	294	297	303	308	310	313	307	302	304	305	300	294
Petrified Forest NP	269	271	274	279	280	282	278	275	276	277	274	270
Pine Mountain Wilderness	238	238	238	247	248	251	252	251	251	249	248	244
Pinnacles NM	211	215	216	222	223	226	225	224	224	223	219	214
Point Reyes NS	128	134	133	132	130	127	122	119	117	121	124	126
Presidential Range-Dry River Wilderness	186	188	189	191	192	192	192	191	190	191	192	190
Rawah Wilderness	297	296	297	296	294	298	300	299	297	299	296	297
Red Rock Lakes Wilderness	261	264	263	266	264	265	261	261	264	266	262	264
Redwood NP	176	182	187	191	192	196	204	206	201	192	180	177
Rocky Mountain NP	261	265	265	262	263	262	258	256	254	258	259	259
Roosevelt Campobello Int Pk	170	173	173	175	172	169	169	166	166	168	171	170
Saguaro NP	252	250	250	248	247	251	252	251	250	252	250	252
Saint Marks Wilderness	182	185	189	190	188	189	187	185	184	187	186	184
Salt Creek Wilderness	245	247	247	250	250	251	251	250	250	250	251	249
San Gabriel Wilderness	262	262	264	268	268	272	273	271	271	271	271	267
San Gorgonio Wilderness	253	255	258	262	262	263	258	254	257	258	256	251
San Jacinto Wilderness	247	247	248	250	250	252	253	251	250	251	252	250
San Pedro Parks Wilderness	280	284	285	286	285	279	277	276	278	281	281	279
San Rafael Wilderness	243	246	250	253	253	256	252	248	249	252	247	244
Sawtooth Wilderness	259	263	269	272	272	274	278	278	277	273	263	259
Scapegoat Wilderness	249	253	255	257	257	257	260	261	258	254	249	249
Selway-Bitterroot Wilderness	251	256	261	264	265	266	270	271	268	262	253	251
Seney Wilderness	179	182	181	182	183	180	178	175	175	178	177	177
Sequoia NP	230	232	232	234	236	239	240	240	239	238	234	233
Shenandoah NP	191	193	193	195	191	190	189	187	186	190	192	190
Shining Rock Wilderness	193	196	197	199	194	191	190	188	188	192	195	193
Sierra Ancha Wilderness	252	253	256	260	261	263	259	256	257	258	256	252
Simeonof Wilderness	138	138	143	141	138	133	128	127	135	144	142	138
Sipsey Wilderness	176	178	180	181	178	175	174	174	174	176	178	176
South Warner Wilderness	243	249	253	256	258	260	263	263	261	257	249	245
Strawberry Mountain Wilderness	227	233	239	242	244	248	252	252	248	238	228	226
Superstition Wilderness	254	256	259	262	263	264	261	258	259	260	258	254
Swanquarter Wilderness	172	174	174	176	174	171	170	169	170	171	173	172
Sycamore Canyon Wilderness	267	268	272	277	278	281	277	273	274	275	272	268
Teton Wilderness	280	282	283	285	285	288	291	292	289	286	281	281

Table 10. Monthly Average Natural Conditions Visual Range In Kilometers												
Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Theodore Roosevelt NP	223	228	231	234	235	238	238	238	237	235	229	225
Thousand Lakes Wilderness	258	259	258	263	262	261	262	265	265	263	256	257
Three Sisters Wilderness	217	223	225	227	231	234	240	240	236	226	217	217
Tuxedni Wilderness	195	198	205	206	206	204	195	192	192	196	196	194
UL Bend Wilderness	235	236	236	237	238	238	240	242	241	238	234	235
Upper Buffalo Wilderness	177	180	182	182	178	178	179	179	177	179	179	177
Ventana Wilderness	213	215	216	223	225	227	227	227	226	225	223	218
Virgin Islands NP	188	189	190	188	187	188	187	185	185	184	183	185
Voyageurs NP	177	179	179	181	180	176	176	175	174	178	175	176
Washakie Wilderness	270	272	272	273	273	276	279	280	277	274	270	270
Weminuche Wilderness	272	273	276	277	277	281	280	276	276	279	275	273
West Elk Wilderness	298	301	305	308	308	312	309	305	306	308	303	300
Wheeler Peak Wilderness	296	300	306	308	307	309	303	300	299	304	301	297
White Mountain Wilderness	265	267	271	273	272	275	273	268	269	272	267	265
Wichita Mountains Wilderness	232	233	232	233	231	233	235	235	236	235	231	232
Wind Cave NP	246	248	250	250	247	249	252	250	247	249	248	246
Wolf Island Wilderness	173	175	176	177	176	172	172	170	170	171	173	172
Yellowstone NP	280	282	283	284	284	287	290	291	288	285	280	280
Yolla Bolly-Middle Eel Wilderness	246	251	254	258	259	262	261	260	260	258	251	248
Yosemite NP	243	245	246	252	253	257	259	259	258	256	251	246
Zion NP	247	249	254	257	259	262	262	260	260	258	254	250

3.4. Ozone

3.4.1. Introduction (Revised)

Ozone is an air pollutant that forms on warm, sunny days when precursor emissions—nitrogen oxides (NO_x) and volatile organic compounds (VOCs)—react in the presence of sunlight. Because ozone is a regional pollutant, precursor sources both near and far from FLM areas can contribute to ozone formation.

Ozone is phytotoxic, causing damage to vegetation throughout the world (Ashmore et al. 2004). Some plant species are more sensitive to ozone than are humans (EPA 2007b). Ozone pollution has been shown to reduce plant growth, alter species composition, and predispose trees to insect and disease attack. Ozone also causes direct foliar injury to many plant species. Affected leaves are often marked with discoloration and lesions, and they age more rapidly than normal leaves (EPA 2007b).

FLAG is intended to provide information to assist the FLMs in identifying ozone impacts to vegetation on lands they manage. Therefore, the objectives of this chapter are to document information currently known about vegetation response to ozone exposure, and to describe FLM procedures for responding to new source review (NSR) permit applications. If the FLMs have evidence that ozone is adversely impacting an area they manage, they will recommend that additional emissions of ozone precursors are minimized until those adverse impacts are mitigated.

3.4.2. Ozone Effects on Vegetation (Revised)

Most ozone effects research has focused on agricultural crops. However, research has identified many native plants in natural ecosystems that are sensitive to ozone (EPA 1996e). Some of these ozone-sensitive plant species have been used as "bioindicators" of ozone to document phytotoxicity of ozone in the field due to ambient ozone. A listing of key literature describing known ozone effects on native vegetation is provided in Appendix G.

The definitions for ozone injury and damage used by FLMs are based on the classical definitions (for example, see Guderian 1977). Injury is all physical or biological responses to pollutants, such as change in metabolism, reduced photosynthesis, leaf necrosis, premature leaf drop, and chlorosis. Damage is reduction in the intended use or value of the biological or physical resource; for example, economic production, ecological structure and function, aesthetic value, and biological or genetic diversity that may be altered through the impact of pollutants.

Ozone enters plants through leaf stomata. It oxidizes plant tissue, causing changes in biochemical and physiological processes. These biochemical and physiological changes occur within the leaf long before visible necrotic symptoms appear (Guderian et al. 1985). Plants must expend energy to detoxify ozone and repair injured tissue that could otherwise be used for growth or for maintenance of plant health. The injured plant cells eventually die if detoxification and repair cannot keep up with ozone uptake. The mesophyll cells under the upper epidermis of leaves are the most sensitive to ozone, and those are the first cells to die. The adjacent epidermal cells then die, forming a small black or brown interveinal necrotic lesion that becomes visible on the upper surface of the leaf. These visible lesions most frequently begin to develop on leaves that have just become fully matured, with older leaves on a stem showing increased amounts of injury. These lesions, termed oxidant stipple[7], are quite specific indicators that the plant has been exposed to ozone. Other plant symptoms that can result from exposure to ozone, with or without the presence of oxidant stipple, include chlorosis, premature senescence, and reduced growth. However, these symptoms are non-specific for ozone since other stressors (e.g., disease, insects) can also cause them to occur. Further, these non-specific symptoms are difficult to quantify in natural ecosystems, although limited data are available from exposure response experiments to estimate growth losses from specific ozone exposures. In general, the only indicator that a FLM has to document that ozone has impacted vegetation is visible symptoms of injury such as oxidant stipple.

In addition to affecting individual plants, ozone can also affect entire ecosystems. Research shows that plants growing in areas with high exposure to ambient ozone may undergo natural selection for ozone tolerance (EPA 2007b). The final result could be the elimination of the most ozone-sensitive genotypes from the area. Regardless of the amount of ozone exposure, the magnitude of plant response may vary depending on the geographic area because of changes in meteorological and climatic conditions, and differences in plant conditions in space and time. Factors of most importance that influence plant response to ozone are the species/genotype, soil moisture, and nitrogen availability. Other factors influencing plant response to ozone include nutrient status, atmospheric humidity, temperature, solar radiation, phenological stage of development, carbon dioxide concentrations, day length, regional climatic differences, other pollutant interactions, and population/ecosystem interactions (EPA 2007b).

Changes in growth, ecosystem form or function, or biological or genetic diversity caused by ozone have been difficult to document in natural ecosystems. However, recent research in Great Smoky Mountains National Park showed that in years with high ozone, tree growth was

7. Specific symptoms of ozone injury in some plant species are different. A few species develop white or tan rather than brown or black lesions. This is termed "fleck" or "weather fleck" instead of oxidant stipple. In conifers, ozone causes banding of necrotic and green tissue near the tips of older needles, termed "chlorotic mottle."

significantly reduced and trees had increased rates of water loss (McLaughlin et al. 2007a). Increased water loss resulted in soil moisture depletion and reduced late-season streamflows (McLaughlin et al. 2007b). The experiment was conducted over a range of forest types and included several different tree species. These findings may have implications for climate change. Climate change is predicted to increase temperatures and drought conditions in some areas. Ozone may exacerbate the effects of drought by increasing water loss from trees.

Given the difficulty in determining ozone-induced physiological or growth changes in natural ecosystems, FLMs will utilize as indicators of ozone effects on vegetation (1) symptoms that are clearly ozone induced such as oxidant stipple, and (2) ozone exposures that have been shown to be phytotoxic.

3.4.3. Established Metrics to Determine Phytotoxic Ozone Concentrations (Revised)

EPA has set primary and secondary ozone standards to protect human health and welfare. On March 12, 2008, EPA revised the primary and secondary ozone standards to 0.075 ppm (8-hour standard). On January 6, 2010, the EPA proposed further strengthening of the primary (human health) ozone standard and establishing a new secondary ozone standard to protect ecosystems and sensitive plants (EPA 2010b). For questions regarding site specific issues the applicant is encouraged to consult with the FLM. More detailed discussions regarding other ozone metrics may be available on the respective agency web sites provided in section 3.4.7.

3.4.4. Identification of Ozone Sensitive AQRVs or Sensitive Receptors (Revised)

FLMs have determined that given the high ecological, aesthetic, and intrinsic value of federal lands, special attention should be given to native species. Ideally, protection efforts would focus on the identification and protection of at risk native species in an area. Unfortunately, AQRV identification is limited by incomplete species inventories and/or lack of exposure/response data for most species of native vegetation. Sensitive species identification will improve as more information becomes available. In the meantime, the Agencies are providing lists of sensitive plant species for each Class I area, i.e., those species that have been observed to exhibit ozone symptoms at ambient ozone exposures. This information is available at the respective agency web sites (see below). However, those ambient levels have not necessarily occurred at the specific Class I area where the plants occur.

Since FLAG 2000, the FLMs have acquired additional information regarding ozone effects to vegetation, including lists of ozone sensitive species. Much of this information is included in the NPS and FWS ARIS data base referenced previously, and will be updated as necessary. The ARIS web site is as follows:

- http://www.nature.nps.gov/air/permits/aris/index.cfm

In addition, the NPS has evaluated the risk to vegetation from ozone exposure at approximately 270 park units. The ozone risk assessment can be found at:

- http://www.nature.nps.gov/air/Permits/ARIS/networks/ozonerisk.cfm

Forest Service pertinent ozone information, including a list of ozone sensitive species, can be found at:

- http://www.fs.fed.us/air

3.4.5. Review Process for Sources that Could Affect Ozone Levels or Vegetation in FLM Areas (Revised)

As mentioned above, NO_x and VOC are ozone precursors. States and the EPA have based ozone control strategies in various parts of the country on the determination of which precursor is most likely to influence the formation of ozone. Information suggests that in areas where ozone formation is driven by VOC emissions, i.e., VOC-limited areas, VOC to NO_x ratios are less than 4:1. In VOC-limited areas, minimizing or reducing VOC emissions is the most effective means of limiting or lowering ozone concentrations. Conversely, in NO_x-limited areas, where VOC to NO_x ratios are greater than 15:1, controlling NO_x emissions is most effective. It is generally thought that most rural areas of the U.S. are NO_x-limited, most or all of the time, with the possible exception of the rural areas of southern California. The FLMs do not have current data to show that all areas are not NO_x limited, nor do they consider VOCs to be unimportant as ozone precursors. However, until there is enough information available for FLAG to determine whether ozone formation in each FLM area is primarily limited by NO_x or VOC emissions, we will assume all FLM areas are NO_x-limited and will focus on control of NO_x emissions. Where FLMs have information indicating a specific area is VOC limited, they will shift the ozone protection strategy to focus on VOC rather than NO_x emissions.

The FLMs recognize that oxidant stipple can occur at hourly ozone concentrations that can be considered natural background levels (Singh et al. 1978). Many of the high hourly background concentrations can be attributed to stratospheric intrusions or stratospheric mixing in the upper troposphere (Singh et al. 1978); but stratospheric intrusions rarely occur in the middle and southern latitudes after May (Singh et al. 1980, Wooldridge et al. 1997), and thus do not coincide with the major portion of the growing season.

However, oxidant stipple has been observed on foliage in the spring when these intrusions can occur. In general, oxidant stipple observed on foliage from June through September cannot be attributed to natural background ozone from stratospheric sources. Low levels of ambient ozone may occasionally occur in the troposphere from non-anthropogenic and non-stratospheric sources.

The occurrence of oxidant stipple necrosis on plant foliage may indicate further ozone induced physiological and growth impacts. Point sources emit precursors that could produce ozone at the FLM area, and increased ozone could induce further injury or damage to vegetation. However, we assume that restriction on increases in ozone precursors will prevent additional ambient ozone and subsequent increases in injury or damage to vegetation in FLM managed areas. It is important that ambient ozone monitoring be conducted by the State or Local air pollution control agency or by the FLM to determine the seasonal ozone exposure.

FLM actions or specific requests on a permit application will be based on the existing air pollution situation at the FLM area(s) that may be affected by the source. Some FLMs may, with appropriate documentation, rely on growth loss rather than foliar necrosis to make an adverse impact finding. Each FLM will determine if actions are warranted to limit emissions that might lead to increased ambient ozone, based on the expected impact of ozone in their particular area.

FLM response will depend on whether or not:

- ozone specific vegetation effects have been documented in the area (as evidenced by foliar injury or damage to vegetation);
- ozone exposure levels occurring in the area are high enough that they could affect vegetation (i.e., ozone exposures are at levels shown to be phytotoxic).

For a project that exceeds the initial annual emissions over distance (Q/D) screening criteria, Figure 6 outlines the general FLM review process for responding to NSR permit applications based on ozone exposure and vegetation effects at the receptor site. As noted in Figure 6, ambient ozone concentrations are considered along with data from exposure response studies (EPA 2007b) to determine whether a source will cause or contribute to phytotoxic ozone levels (i.e., levels toxic to plants) at the affected site. The FLM may ask the applicant to calculate the ozone exposure values if these data are not already available. Ozone damage to vegetation is determined from field observations at the impacted site.

Management decisions regarding acceptance of an existing or future ozone exposure will be area-specific and may differ significantly between agencies, or even regionally within agencies. Each FLM will determine if injury and/or damage are necessary to warrant action, based on the expected impact in the area they manage. The decisions are based on the FLM interpretation of regulations, past experience in the NSR arena, availability of ozone effect exposure/response information for species that occur in the area, and other factors. The FLM may also consider current trends in ozone exposures and meteorological conditions during peak ozone exposures (because dry soil conditions may induce plants to close stomates to limit water loss, thus limiting ozone uptake), as well as expected reductions in ozone precursor emissions. The FLM will negotiate with the NSR permit applicant and the permitting authority regarding possible mitigation strategies (e.g., using more efficient emissions control technologies, obtaining emission offsets, etc.).

3.4.6. Further Guidance to FLMs (Revised)

As mentioned above, limited information about ozone exposure/response relationships in plants and lack of an ozone source/receptor model make it difficult to protect FLM areas from the effects of ozone from new sources. However, there are other area-specific gaps in information that also limit protection efforts. It is important for local land managers to attempt to collect the missing information. This section provides guidance specifically to FLMs on what types of data should be collected and how the data could be collected.

Identifying and Monitoring Ozone-sensitive AQRVs

Although many FLM areas have identified ozone-sensitive plant species in their areas, most areas need more details regarding plant species location and abundance. FLAG recommends FLMs gather this information, where needed, and refine their lists of area-specific ozone-sensitive plants. The FLMs have placed ozone sensitive plant species lists for many of their areas in the NRIS-AIR or Air Resources Information System databases.

FLAG recommends that once local FLMs have developed lists of potentially sensitive AQRVs specific for their site, they conduct surveys to detect the presence of ozone-induced foliar injury on the selected species. The USFS Forest Health Monitoring (FHM) Program and the National Park Service Inventory and Monitoring Program have developed foliar injury survey protocols and QA/QC procedures that can be used to collect this information. Another resource is the foliar injury training module developed by the NPS Air Resources Division and The Pennsylvania State University, available at http://www.nature.nps.gov/air/edu/O3Training/index.cfm. This module helps field staff identify and quantify ozone injury symptoms on plant foliage. Field crews should obtain proper training and field experience in identifying foliar injury symptoms before surveys can be conducted.

Ideally, to verify ozone-induced foliar injury symptoms in the field, exposure/response fumigation studies should be conducted on these species, using concentrations that reflect current ambient exposure. Plants should also be tested at

higher exposures, simulating increased levels of ambient ozone that might occur in the future. Due to the expense of constructing and operating such systems, it would be most appropriate for agencies to join resources and develop regional fumigation facilities. At a minimum, such facilities should be constructed both in the eastern and western U.S., since ambient conditions at an eastern facility might not be appropriate for western species and vice versa.

Ambient Ozone Monitoring

Many FLM areas do not currently have either on-site or nearby ambient ozone monitoring data. FLAG recommends that local FLMs make every effort to collect this information and that they use quality-assured ambient ozone monitoring protocols developed by the EPA and the state air quality agency. Continuous monitoring is desirable to determine the temporal dynamics of ozone exposure for vegetation. Unfortunately, continuous monitoring is expensive and requires electric power that is often not available in or near remote FLM areas. When installing a continuous monitor is not an option, FLAG recommends use of passive monitors. Passive monitors give total exposure loading values (SUM00) for a specified period of time. The data are useful for indicating year-to-year changes in total ozone exposure at an individual site, and for indicating where continuous monitors should be installed. However, FLMs recognize the limitation of passive samplers in relating ozone exposure to plant response.

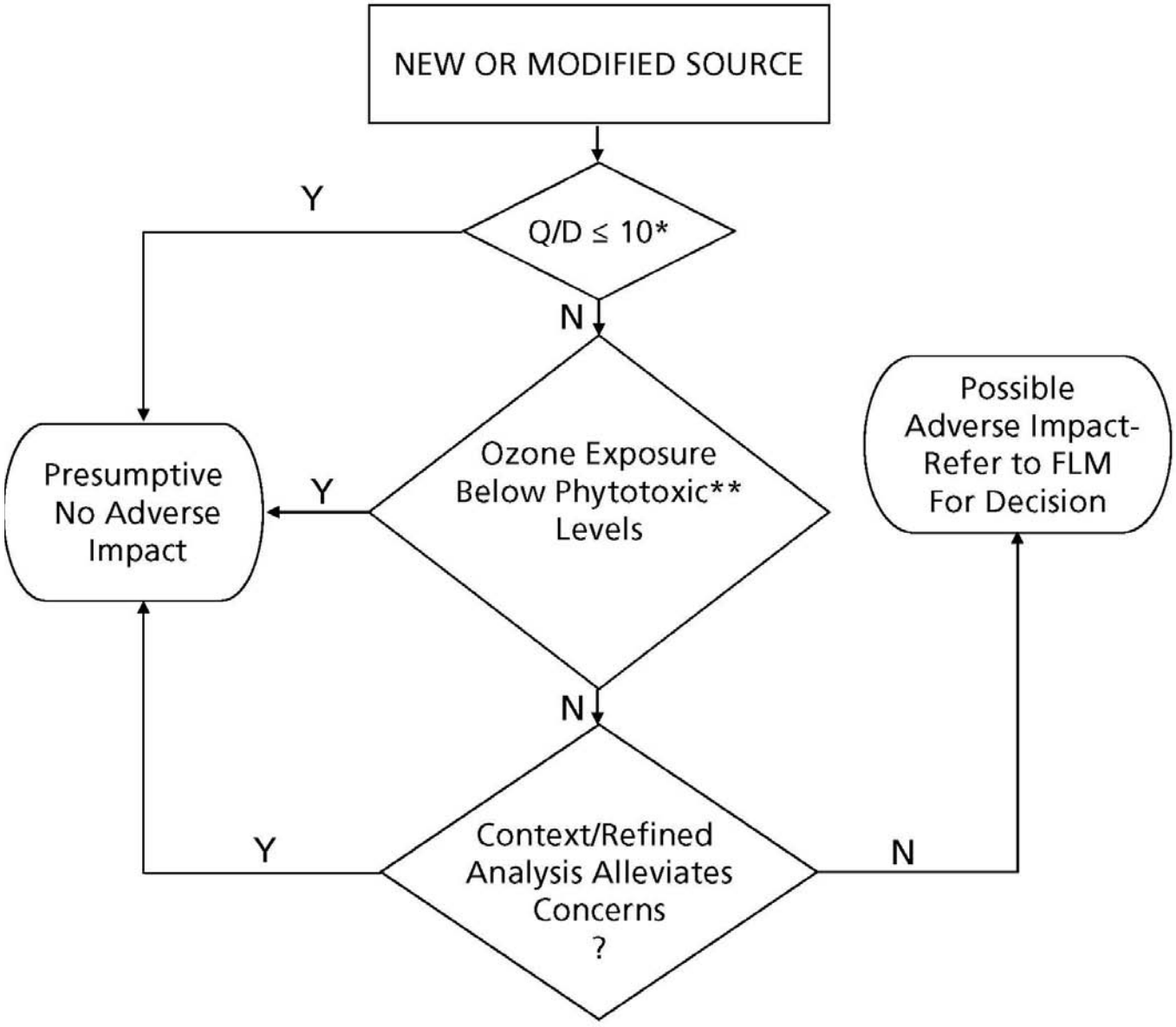


Figure 6. FLM Assessment of Potential Ozone Effects from New Emissions Source (Revised)
*Q/D test only applies to sources located greater that 50 km from a Class I area.
**Note: Ambient ozone concentrations are considered along with data from exposure response studies (EPA 2007b) to determine whether a source will cause or contribute to phytotoxic ozone levels (i.e., levels toxic to plants) at the affected site.

3.4.7. Ozone Air Pollution Web Sites (Revised)

EPA ozone information:

- http://www.epa.gov/ozone
- http://www.epa.gov/castnet

NPS ozone information:

- http://www.nature.nps.gov/air/permits/aris/index.cfm
- http://www.nature.nps.gov/air/Monitoring/network.cfm
- http://www.nature.nps.gov/air/studies/ecoOzone.cfm

FWS Information:

- http://www.fws.gov/refuges/whm/AirQuality/index.html

U.S. Forest Service information:

- http://www.fs.fed.us/air
- http://www.fs.fed.us/psw/programs/atdep

Ozone effects research, USDA ARS, North Carolina:

- http://www.ars.usda.gov/Main/docs.htm?docid=8453

Ozone exposure metrics for vegetation:

- http://www.asl-associates.com/

3.5. Deposition

3.5.1. Introduction (Revised)

Atmospheric deposition has been studied extensively throughout the world, beginning in the 1800's in England, Sweden, Norway, and Germany. Research has primarily focused on the deposition of acidic pollutants and long-term acidification. Many publications describe current conditions, monitoring and modeling methods, and the results of acidification experiments. In the United States, research on acidification was first begun in 1962 at Hubbard Brook, New Hampshire. Subsequent work in the Adirondack lakes and other areas furthered the understanding of acid deposition effects. It is now recognized that, in addition to causing acidification, deposition of pollutants can affect many ecosystem characteristics, including nutrient cycling and biological diversity.

Although much progress has been made to control sulfur dioxide and nitrogen oxide emissions, deposition of sulfur (S) and nitrogen (N) compounds continues to be a problem in North America and Europe (EPA 2007a). As a result, certain sensitive freshwater lakes and streams continue to lose acid-neutralizing capacity (ANC) and sensitive soils continue to be acidified. Other ecosystems, including forests, grasslands, estuaries, and N-limited lakes exhibit unwanted fertilization and other effects from excess N deposition. In this section, the Agencies focus on S and N deposition and associated effects to ecosystems, but other potentially damaging pollutants are routinely deposited. For example, mercury emitted from coal-fired powerplants, incinerators, and other sources deposits into ecosystems and accumulates to sometimes toxic levels in fish and wildlife (EPA 1997). EPA sampled fish from over 75,000 lakes nationwide and found that mercury concentrations in large predatory fish exceeded the human health screening value for mercury in nearly half the lakes (EPA 2009b). The Great Waters Program found that, in addition to mercury, airborne toxics including dioxins, furans, polycyclic organic matter, polychlorinated biphenyls (PCBs), and pesticides are deposited widely across the Great Lakes, the Chesapeake Bay, Lake Champlain, and many coastal estuaries, posing ecological and human health risks (EPA 2000a). Even in relatively remote western and Alaska national parks, deposition has increased concentrations of certain toxic compounds in fish and wildlife above health thresholds (Landers et al. 2008).

Federal Land Managers (FLMs) have documented the effects of S and N deposition on many air quality related values (AQRVs). Documented effects include acidification of lakes, streams, and soils; leaching of nutrients from soils; injury to high-elevation spruce forests; changes in terrestrial and aquatic species composition and abundance; changes in nutrient cycling; unnatural fertilization of terrestrial ecosystems; and eutrophication of estuarine and some lake systems. FLMs recognize that other undocumented effects may also be occurring.

The FLAG deposition subgroup was formed to identify common approaches among these agencies for evaluating atmospheric deposition and its effects on AQRVs. In addition, the subgroup was directed to recommend methods for establishing critical deposition loading values ("critical loads") and, where possible, recommend such critical loads for specific areas. These tasks were assigned to Phase I or Phase II, depending on their degree of difficulty.

During the scoping process, the FLAG Deposition Subgroup determined that Phase I tasks would include the summarization of information currently available about deposition and its effects on FLM areas and the development of recommendations on methods to model and evaluate current and future deposition and its effects on AQRVs. In addition, critical load values, where available from previous FLM guidance documents, would be referenced. FLMs agreed that site-specific AQRV and critical load information would be maintained on FLM web sites, rather than included in the Phase I report. In this way, the information can be updated and the most recent versions made quickly available to the public. Some of this information is already available on FLM web sites, and the FLMs are committed to entering remaining available information as soon as possible.

The subgroup recognizes that the development and refinement of site-specific critical load values for all FLM areas are crucial for AQRV protection. However, because of the complexity of this undertaking, and the lack of information for many areas, it was deferred to future FLAG development.

Future deposition effects work will involve developing methods for establishing critical deposition loading values for FLM areas, and establishing critical loads for areas with adequate information. For areas lacking sufficient information to determine critical loads, strategies will be developed to obtain needed information. Previously established critical loads will be reviewed and refined as necessary. The subgroup will also explore alternative methods for estimating background deposition rates, including extrapolation techniques or modeling that considers the spatial scale of ecosystems and differences in elevation. Methods for addressing problems with dry deposition and cloud and fog deposition measurements will also be considered. In addition, future work may provide research or monitoring recommendations to improve our understanding of deposition and its effects, including effects on cultural resources.

3.5.2. Current Trends in Deposition (Revised)

Title IV of the Clean Air Act was passed by Congress as part of the 1990 Clean Air Act Amendments to reduce emissions of sulfur dioxide and nitrogen oxides from fossil fuel-burning power plants in order to reduce deposition of S and N compounds and protect ecosystems suffering damage from acid deposition. Since the implementation of Title IV, wet sulfate deposition, a major component of acid rain, has significantly decreased. Average annual sulfate deposition in the Northeast in 2000–2002 was 40% lower than it was in 1989–1991, deposition in the mid-Atlantic and Midwest was 35% lower, and deposition in the Southeast was 25% lower (NAPAP 2005).

Wet nitrate deposition, on the other hand, has not decreased regionally from historical levels because of the relatively moderate reduction in nitrogen oxides from power plants and the continuing large contribution (over 50% of total nitrogen oxides emissions) from other sources of nitrogen oxides such as vehicles and nonroad vehicles (NAPAP 2005).

Deposition monitoring data can be used to identify decreases in S and N deposition due to decreases in emissions. The National Atmospheric Deposition Program (NADP) provides one of the best and most comprehensive long-term records of wet deposition chemistry in the U.S. Annual reports on deposition nationwide as well as deposition trend plots for all NADP sites are available at http://nadp.sws.uiuc.edu/. An analysis of long-term trends (1985-2004) in precipitation chemistry from NADP sites across the U.S. found that concentrations of sulfate have decreased in nearly all parts of the country. Nitrate, however, has increased in many areas and ammonium, another component of N deposition, has also increased significantly in many areas, particularly in the West (Lehmann et al. 2005). Publications on trends in deposition are available from NADP at:

- http://nadp.sws.uiuc.edu/lib/

In this chapter, it is assumed that S is deposited into the environment primarily as sulfate ion and N is deposited primarily as inorganic nitrate and ammonium ions. Other ionic forms of S and N occur in the atmosphere, but information on their deposition into ecosystems is limited. For example, organic N in deposition is not routinely measured because of the expense and complexity of the measurements. Organic N includes peroxyacetyl nitrate (PAN) (produced in the atmosphere by nitrogen oxides and hydrocarbon reactions), urea, and amino acids. Both natural and anthropogenic processes contribute to organic N formation, including industry, agriculture, biomass burning, and biological activity. Limited monitoring suggests that organic N deposition varies widely, but on average constitutes about 30 percent of total N (Neff et al. 2002)

3.5.3. Identification and Assessment of AQRVs (Revised)

AQRVs sensitive to pollutant deposition have been identified in various documents published by the USFS, NPS, and FWS, which are listed in the 'General References' of Appendix G of this report. The FLMs have previously used a combination of approaches to identify AQRVs, including national and regional workshops, regional reviews, and site-specific studies. AQRV identification was based on information from peer-reviewed scientific literature and expert judgment. Because information on AQRVs may change as new data become available, the FLMs agree that AQRV information will be made available on FLM web sites to allow for updating and improve accessibility, as discussed in the Introduction to this chapter.

Information on AQRVs for many USFS Class I areas can be found at

- http://www.fs.fed.us/air

The USFS is currently adding to and updating this information.

Information on AQRVs for NPS Class I areas and some FWS Class I areas is available from NPS Air Web at:

- http://www.nature.nps.gov/air

Information on AQRVs for FWS Class I areas is under development at:

- http://www.fws.gov/refuges/whm/AirQuality/index.html

Table 11. Indicators for monitoring and evaluating effects from deposition of S and N (Revised)	
Ecosystem	**Indicators for Sulfur Deposition**
Freshwater	Chemical change (ANC depression), changes in phytoplankton and benthic community composition, species diversity, biomass
Terrestrial	Leaching of soil cations, soil acidification, mobilization of aluminum ions; Lichen species and vitality
Estuarine	Saltwater not sensitive to S deposition; leaching of nutrients may occur in sandy nearshore soils
Ecosystem	**Indicators for Nitrogen Deposition**
Freshwater	Chemical change (ANC depression), changes in phytoplankton and benthic community composition, species diversity, biomass
Terrestrial	Changes in: litter and soil carbon and N dynamics; biomass; soil N processes; litter decomposition rates; soil microbe functional groups; soil organic matter quality and quantity; soil water chemistry; Lichen species and vitality
Estuarine	Changes in: phytoplankton species composition and biomass; aquatic invertebrates; seagrass health and distribution; nutrient ratios; dissolved oxygen; trophic status

FLMs recommend that permit applicants consult with the appropriate FLM to determine the need for an AQRV analysis and, if applicable, the methods for the analysis.

All FLMs use a similar conceptual approach to identify AQRVs that reflects the FLMs' interest in maintaining the integrity of ecosystem structure and function and protecting the most sensitive ecosystem components. AQRVs can be categorized by the type of ecosystem in which they are found, such as terrestrial, freshwater, and estuarine ecosystems. Each ecosystem and its AQRVs responds somewhat differently to deposition and approaches to evaluating deposition effects must therefore be developed accordingly. In terrestrial ecosystems, detection of changes in production, decomposition, and nutrient cycling processes provide information on deposition stress. In aquatic and estuarine ecosystems, detection of changes in water chemistry and aquatic community composition and structure provide similar information. Table 11 summarizes AQRV indicators that may be used to assess effects in various ecosystems.

Terrestrial, freshwater, and estuarine AQRVs are discussed below. In addition, methods to evaluate S- and N-induced deposition stress are discussed.

Terrestrial Ecosystems

Terrestrial ecosystem AQRVs include flora, fauna, and soils. FLMs have identified, where possible, AQRVs, or characteristics of AQRVs, most likely to be sensitive to S and N deposition ("sensitive receptors"). For example, high-elevation spruce forests may be sensitive receptors. FLMs assess the condition of these sensitive receptors by evaluating some aspect of the receptor (the "sensitive receptor indicator" or "indicator"). For example, an indicator for high-elevation red spruce forests is the occurrence and extent of winter foliar injury. In general, the FLM has focused on deposition effects to vegetation and chemical receptors in terrestrial ecosystems, with little emphasis on fauna. In addition, there is increasing awareness among FLMs that certain soil fauna (e.g., microorganisms and invertebrates) are very sensitive to deposition and can be used as sensitive receptors.

In terrestrial ecosystems, sulfate production is regulated primarily by chemical processes (Johnson et al. 1983) and it is rarely a limiting nutrient. Soil response to acidic deposition can be evaluated by monitoring the leaching of essential soil cations, soil acidification, and mobilization of ionic aluminum. These processes have been studied both in field and laboratory experiments, and are defined in detail in the literature (Mollitor and Raynal 1983; Richter et al. 1983; Johnson et al. 1983; Reuss and Johnson 1986). Effects of S deposition can be detected by monitoring calcium and magnesium ions and S in the litter layer and surface soils; calcium, magnesium, potassium, and sulfate ions in soil solution; cation exchange capacity (CEC); and base saturation.

In general, biological AQRVs do not provide reliable indicators of S deposition in terrestrial ecosystems except under extreme S deposition. Lichens have been used in some areas as biomonitors to demonstrate spatial trends in S deposition, particularly in areas with pronounced S deposition gradients. For example, isotopic analysis of lichens from Mt. Zirkel Wilderness, Colorado, indicated that power plants in the nearby Yampa Valley were the source of elevated S in the lichens (Jackson et al. 1996).

Unlike S, the production and mobility of N in ecosystems is regulated almost entirely by biological processes. N is a limiting nutrient in many terrestrial ecosystems. In these ecosystems, growth of plants is limited by N availability; additional N from atmospheric inputs increases plant growth. Most ecosystems can retain and process significant additions of N, with resulting increases in production and changes in species diversity, biomass, and nutrient cycling. However, these changes are usually considered to be inconsistent with desired ecosystem conditions for natural areas. The ability to retain and process N varies significantly

depending on watershed successional status, site and fire history, soil conditions, vegetation, and other non-human factors. When N inputs exceed an ecosystem's assimilation capacity, N is lost or leached, usually as nitrate, from the soil and can be detected in adjacent streams or lakes. This may occur following a major disturbance such as fire, logging, land use change, grazing, agriculture, or where atmospheric N deposition or experimental inputs exceed what the ecosystem can assimilate (Fenn and Dunn 1989; Fenn 1991, Fenn et al. 1996; Adams et al. 1997).

Studies in northern Europe (Dise and Wright 1995) found that European forests leached detectable levels of nitrate at inputs of about 10-25 kilograms N per hectare per year (kg N $ha^{-}1yr^{-1}$). Tundra and high-elevation alpine sites may leach N at much lower levels of input. Mountain watersheds in the western U.S. show signs of N leakage at wet deposition levels of 3-5 kg N $ha^{-1}yr^{-1}$ (Eilers et al. 1994; Williams et al. 1996; Williams and Tonnessen, in review). However, even high elevation, poorly vegetated ecosystems with limited soil development can process more than 80% of the atmospheric N input before it reaches the aquatic system (Campbell et al. 1995, Kendall et al. 1995). Although nitrogen leaching has often been used as an indicator of excess N deposition, major changes occur in below- and above-ground biomass, species diversity, and nutrient cycling long before N input levels are sufficient to cause nitrate leaching (NAPAP 1993; Tilman et al. 1997; Vitousek et al. 1997). For example, with ambient deposition rates of 7-10 kg N $ha^{-1}yr^{-1}$, a Minnesota Long-Term Ecological Research (LTER) grassland study observed shifts from native, warm-season grasses to low diversity mixtures dominated by cool-season grasses and a greater than 50% decline in species richness (Wedin and Tilman 1996; Tilman et al. 1997). Significant losses in terrestrial diversity may have already occurred over extensive areas of the U.S., particularly in forest understories, shrublands, grasslands, and in soil microbial communities. (Suding et al. 2005; Weiss 2006).

Because significant ecological changes may occur before nitrate loss can be detected, more sensitive indicators than nitrate leaching are needed to evaluate N deposition effects. Such indicators include changes in carbon and N dynamics of litter and soil and biomass (Aber and Driscoll 1997; Magill et al. 1997). With knowledge of inputs and small-scale N fertilization studies, changes in soil organic matter quality and quantity in response to N deposition can be evaluated. Soil microbial communities control the quantity and quality of N available to ecosystems and may be very sensitive indicators of N deposition. Changes in soil microbe functional groups or biomass may provide good estimates of ecosystem critical loads and incremental effects. Soil N mineralization, small root growth, and carbon:nitrogen ratios of soil and microbial biomass are also sensitive to N deposition. Evidence suggests that current deposition rates may alter the production of dissolved organic carbon and organic N compounds in soils, which are important nutrient and energy sources for both terrestrial and aquatic ecosystems (Grandy et al. 2008; Aber et al. 1995; Sinsabaugh et al. 2005). These could also be used as indicators of N deposition effects. However, because there are many other variables that also affect soil processes, it may be very difficult to discern effects on any soil indicators that are solely attributable to N.

Freshwater Ecosystems

AQRVs in freshwater ecosystems include lakes and streams and their associated flora and fauna. Sensitive receptors include water chemistry and clarity, phytoplankton, zooplankton, fish, amphibians, macroinvertebrates, and benthic organisms. Water chemistry indicators that respond to deposition include pH, ANC, conductance, cations and anions, metals, and dissolved oxygen. Physical indicators, such as water clarity, and biological indicators, including species diversity, abundance, condition factor and productivity of fish, amphibians, macroinvertebrates, and plankton can also be used to detect deposition effects in aquatic ecosystems. Much research has been done on the sensitivity of aquatic species to deposition, many of which are discussed in the 1990 National Acid Precipitation Assessment Program (NAPAP) State of Science report (NAPAP 1991a) and the 1998 NAPAP report (NAPAP 1998).

Sulfur is not a limiting nutrient in freshwater ecosystems. However, there are regions of the U.S. where a relatively high percentage of surface water is sensitive to current acidic inputs. These include portions of the Northeast (particularly Maine and the Adirondack and Catskill Mountains), southeastern streams, and some high elevation western lakes, particularly in the Rocky Mountains (NAPAP 2005). There are a number of FLM areas in acid-sensitive regions, including national parks, national forests, and wilderness areas. In these areas, S deposition can cause decreases in ANC and pH. For these sensitive or low-ANC waters, the best approach to quantify S deposition effects is the procedure currently used, monitoring changes in ANC and pH.

Nitrogen deposition, like S deposition, can cause episodic acidification of surface water in certain sensitive high-elevation ecosystems that have low-ANC headwater lakes and streams. Episodic acidification occurs in these areas when deposition is as low as 3-5 kg N $ha^{-1}yr^{-1}$ (Williams et al. 1996).

Estuarine Ecosystems

AQRV sensitive receptors in estuarine ecosystems include plankton, sea grasses, and water chemistry and clarity. Associated coastal forest and dune soils may also be useful as sensitive receptors. Water and soil nutrient concentrations, phytoplankton species composition and abundance, sea

grass health, and dissolved oxygen concentrations can be used to evaluate deposition effects.

In estuaries, S is not a limiting nutrient. In addition, estuarine waters are highly buffered and, therefore, not subject to acidification. However, many coastal forest and dune soils are dominated by sandy soils that are sensitive to leaching of limiting nutrients because of very low cation exchange capacity (Au 1974). Monitoring for change in estuarine areas with high S deposition should therefore focus on soil ion mobility. As soil calcium and magnesium levels are generally adequate because of deposition from marine sources, potassium is likely the only limiting nutrient subject to significant loss by sulfate leaching.

The role of N in estuaries is probably the best-documented example of anthropogenic alteration with a literature record dating back to the 1950s. Production and use of fertilizers, land use changes, and fossil fuel combustion have greatly increased the available N, normally a limiting nutrient, which enters coastal waters (Galloway et al. 2003). This has increased estuarine production and accelerated the process of eutrophication. Eutrophication can result in dramatic algae blooms, anoxia, the production of toxic hydrogen sulfide gas, and species extirpation in estuarine ecosystems. Human induced eutrophication has been documented for many areas along the Atlantic and Gulf coasts, including the Chesapeake Bay, Tampa Bay, Sarasota Bay, Florida Bay, and Long Island Sound.

A number of FLM areas along the Atlantic and Gulf coasts contain significant coastal waters that may be sensitive to eutrophication. Little is known about excess N effects in most of these areas, although eutrophication is well documented in Florida Bay, located in Everglades National Park. Also, recent evidence indicates that coastal waters in Chassahowitzka Wilderness (Florida) experience N-induced algal blooms (Dixon and Estevez in draft). In most coastal waters, 10-45% of the N entering the system is atmospheric, either from direct deposition to surface water or deposition to the watershed. Complete elimination of atmospheric N inputs would not entirely mitigate ecosystem change due to N because of the substantial contributions from agricultural and urban runoff. However, for most estuaries, any reduction in N input would be beneficial in restoring ecosystem structure and function.

The monitoring procedures recommended, and currently used, in estuaries are similar to those used in freshwater, with emphasis on incremental changes in plankton, aquatic plant, benthic, and invertebrate community composition; species diversity, distribution, and biomass; and ecosystem trophic status.

Significance of Long-Term Monitoring to Evaluate Trends and Validate Modeling

Long-term monitoring is critical to evaluate trends in deposition and deposition effects. Monitoring programs should concentrate not only on areas with high past and/or present sulfate, nitrate, or ammonium deposition, but also in areas that are very sensitive to deposition and in areas where deposition is expected to increase. For selected monitoring sites, the FLM should (1) obtain ion deposition data for the site, as from NADP or CASTNet, (2) identify sensitive AQRVs and appropriate variables to monitor, (3) evaluate the present condition of the sensitive AQRVs, (4) determine the degree to which results from one site can be extrapolated to other FLM areas in the region, and lastly (5) implement a long-term monitoring program, using carefully selected variables.

Long-term monitoring data are also needed to support and validate models used to predict deposition and deposition effects, including the effects of increases or decreases of S and N on ecosystems. Long term studies in both aquatic and terrestrial ecosystems such as Hubbard Brook, Lake Tahoe, and the Experimental Lakes Area have provided useful information for modeling (Bormann and Likens 1967; Holm-Hanson et al. 1976; Likens and Bormann 1977, Leonard et al. 1979; Byron and Eloranta 1984; Schindler et al. 1985; Schindler 1987; Schindler et al. 1990; Jassby et al. 1995). NAPAP and the National Science Foundation LTER program have addressed monitoring to meet modeling needs in both terrestrial and aquatic ecosystems.

Data requirements to support models vary, but the quality of input data will determine the quality of a model's predictions. Modeling is further discussed in the 'Other AQRV Identification and Assessment Tools' (see section 3.5.5).

3.5.4. Determining Critical Loads (Revised)

FLAG 2000 introduced the concept of critical loads as it relates to air resource management in Class I areas. Since FLAG 2000 was published, the Agencies have adopted the widely used definition of critical load, "the quantitative estimate of an exposure to one or more pollutants below which significant harmful effects on specified sensitive elements of the environment do not occur according to present knowledge" (Nilsson and Grennfelt 1988). Critical loads have been widely accepted in Europe and Canada as a basis for negotiating control strategies for transboundary air pollution (Posch et al. 1997).

In Canada, researchers have estimated the critical loads of S in wet deposition necessary to protect moderately sensitive lakes in eastern provinces. That value, equivalent to 6.7 kg $ha^{-1}yr^{-1}$ of S in wet deposition, was used by Canada to argue for the U.S. to implement the Clean Air Act Amendments of 1990, which call for the initial reduction of sulfur dioxide

emissions in the eastern U.S. and later from all electric utilities nationwide. With additional data on lake and stream chemistry available for sensitive systems in Nova Scotia, Ontario, and Quebec, the Canadians are now recommending a more stringent critical load, equivalent to 2.7 kg $ha^{-1}yr^{-1}$ of wet deposition S.

In both European countries and in North America, attention has expanded beyond ecosystem damage caused by S deposition to ecosystem damage caused by N deposition. In some European forests, chronically high N deposition has exceeded the assimilation capacity of local ecosystems, resulting in the release of nitrate into surface waters (Dise and Wright 1995). Watersheds that are leaking nitrate into surface waters during the growing season, are referred to as "N saturated" (Aber et al. 1989). Nitrogen saturation has been linked to forest decline in Europe (Schulze 1989). Based on a set of regional N addition experiments conducted at sites in northern Europe (NITREX), Wright (1995) recommended a N critical load of less than 10 kg $ha^{-1}yr^{-1}$ to protect European forests and fresh waters from N saturation. However, this critical load does not protect ecosystems from the changes caused by N deposition prior to actual N saturation, including shifts in composition and abundance of soil fauna species and alterations in soil chemistry. (Fenn et al. 2003; Driscoll et al. 2003)

In the United States, two states have attempted to set deposition standards or critical loads to protect sensitive ecosystems. In 1982, the State of Minnesota passed the Acid Deposition Control Act to limit wet sulfate deposition to 11 kg $ha^{-1}yr^{-1}$, which is equivalent to 3.7 kg S $ha^{-1}yr^{-1}$. At this sulfate level, precipitation pH was likely to remain above 4.7, which would protect lakes with ANC less than 50 microequivalents per liter (µeq l^{-1}).

In 1989, the California legislature adopted the Atmospheric Acidity Protection Act, which required the Air Resources Board (CARB) to "develop and adopt standards, to the extent supportable by scientific data, at levels which are necessary and appropriate to protect public health and sensitive ecosystems from adverse effects resulting from atmospheric acidity" (CARB 1993). An assessment of existing data identified the high elevation watersheds, surface waters, and mixed conifer forests of the Sierra Nevada and the Los Angeles Basin as sensitive ecosystems. CARB analyses suggested that appropriate standards would include a critical load value for inorganic N to protect forests, and critical loads for both N and S to protect poorly buffered lakes and streams. However, no acidity standards to protect human health or critical loads to protect ecosystems have been set in California to date.

The Clean Air Act Amendments of 1990, Title IV, section 404, called on the Environmental Protection Agency (EPA) to prepare a report on the feasibility and effectiveness of setting deposition standards nationwide to protect sensitive aquatic and terrestrial resources. The completed report includes a number of modeling analyses that project the effect of reductions in both S and N deposition in areas studied during NAPAP. EPA concluded that deposition standards could not be set at this time because of 1) the lack of clearly defined policy regarding appropriate or desired goals for protecting sensitive aquatic or terrestrial resources, and 2) key scientific uncertainties, particularly regarding nitrogen watershed processes. In addition, EPA recognized that a national deposition standard might be inappropriate because of differences among ecosystems. However, in response to public comments on the report, EPA stated that "Given an adequate level of monitoring and assessment data, Class I areas could serve as potential targets for standard setting activities." (EPA 1995)

Since FLAG 2000, other U.S. agencies and organizations have started considering how to work with critical loads. A National Academy of Sciences Report, *Air Quality Management in the United States* (2004), recognized the potential of critical loads for establishing standards to protect ecosystems, prompting the EPA to explore critical loads as an accountability tool to assess ongoing programs. Also, in the 2005 Prevention of Significant Deterioration for Nitrogen Oxides Final Rule, EPA stated it would consider critical loads information from any state as part of their air quality management approach, including whether such an approach satisfies PSD requirements. (EPA 2005.) The U.S. has signed, but not ratified, the European Union's protocol for establishing critical loads, contained in the 1999 *Protocol to Abate Acidification, Eutrophication and Ground-level Ozone (AKA The Gothenburg Protocol)*, available at:

- http://www.unece.org/env/lrtap/multi_h1.htm

In 2006, EPA held the Multiagency Critical Loads Workshop to share information on critical loads and to develop a broad federal strategy for planning, executing, and evaluating critical loads projects, and to consider critical load use in a policy or management framework. As a result of recommendations from the workshop, the Critical Loads Ad-Hoc Committee (CLAD) was formed to foster critical loads science and development. Information on CLAD and the Multiagency Critical Loads Workshop Report are available at:

- http://nadp.sws.uiuc.edu/clad/

In 2008, EPA used critical loads to assess progress under the Acid Rain and related programs. For the analysis, EPA compared critical loads exceedances in Adirondack lakes before and after implementation of acid rain controls (EPA 2009a).

Critical Loads in FLM Areas (Revised)

In the Clean Air Act, as amended in 1977, Congress gave FLMs an "affirmative responsibility" to protect AQRVs in Class I areas from the adverse effects of air pollution.

Congress' intent was, "…In cases of doubt the land manager should err on the side of protecting the air quality-related values for future generations…" (Senate Report No. 95-127, 95th Congress, 1st Session 1977). In an effort to ensure AQRV protection, FLMs have established critical loads for many FLM areas. FLMs agree that a critical load should protect the most sensitive AQRVs within each FLM area and should be based on the best science available. As new scientific information becomes available, critical loads should be reviewed and updated. Critical loads should ensure that no unacceptable change occurs to the resource.

A journal article published in the July 2005 issue of *BioScience*, entitled "Protecting Resources on Federal Lands: Implications of Critical Loads for Atmospheric Deposition of Nitrogen and Sulfur" (Porter, Blett, Potter, Huber 2005) provides an update on the Agencies' perspectives with respect to critical loads. Among other things, the article describes the history of critical loads, the advances in science related to critical loads, and how to apply the concept of critical loads (including some specific case studies). Subsequent articles provide additional information and perspectives on critical loads (Burns et al. 2008; Dennis et al. 2007). These and other articles and reports on critical loads are available from:

- http://www.nature.nps.gov/air/Studies/criticalLoads/index.cfm
- http://www.nrs.fs.fed.us/clean_air_water/clean_water/critical_loads/

FLMs have used a combination of approaches to establish critical loads, including national and regional workshops, regional reviews, and site-specific studies (see Appendix G). In all cases, the FLMs have used peer-reviewed scientific literature and expert judgment to make their decisions. For example, the NPS has compiled regional reviews that have evaluated existing information on air quality, deposition, and effects on AQRVs in national parks. For these reviews, NPS grouped parks by region and ecosystem type, including the Pacific Northwest, the Colorado Plateau, and the Rocky Mountains, and conducted an empirical assessment of the status of aquatic and terrestrial resources. An analysis of deposition effects was done, using current deposition data for S and N and effects information from field observations and research. These reviews provide the basis for critical load development by identifying sensitive resources and impacts to those resources. Park-specific information on sensitive resources, impacts, and critical loads is available at:

- http://www.nature.nps.gov/air/permits/aris/index.cfm

The USFS has conducted a series of national and regional workshops to establish critical loads and concern thresholds. In the late 1980s, the USFS published prototype methods for evaluating the effects of acid deposition on AQRVs (Fox et al. 1989; Fox et al. 1987). Subsequently, the USFS held regional workshops to develop updated and more area-specific screening procedures for new air pollutant emissions sources (Adams et al. 1991; Peterson et al. 1992; Haddow et al. 1998; Peterson et al. 1993; Stanford et al. 1997). These workshops were comprised of national and regional USFS land managers, deposition experts from the academic and air pollution research community, and agency air quality professionals. Dependent on the workshop leadership, each regional workshop followed a slightly different process and a variety of outputs and formats resulted. However, all workshops used a collaborative process to determine S and N deposition rates that would pose a risk to the aquatic and terrestrial ecosystems protected in FLM areas, while addressing the scientific uncertainty inherent in ecosystem response to acidic deposition. Critical load guidelines for many USFS Class I areas are published in the regional workshop reports (see Appendix G) and are available at:

- http://www.fs.fed.us/air

As resources permit, the Agencies will develop methods and a process for establishing critical deposition loading values for all FLM areas and for recommending critical loads for areas where adequate information exists. For areas lacking sufficient information to determine critical loads, the Agencies are developing strategies to obtain needed information.

Current information and links on critical loads work being done by the U.S. Forest Service can be found at the following web site:

- http://www.fs.fed.us/air

The Agencies anticipate using critical loads as they are developed as an assessment tool, and, in concert with the Deposition Analysis Thresholds and Concern Thresholds (see below), a tool for assessing new source impacts. The Agencies also intend to continue to consult with States and the EPA as critical load development work progresses.

3.5.5. Other AQRV Identification and Assessment Tools (Revised)

In addition to AQRV monitoring, there are several tools available to the FLM for identifying AQRVs and assessing the response of sensitive AQRVs to pollutant deposition. These include the Air Resources Information System (ARIS), the Natural Resource Information System – Air Module (NRIS-Air), and deposition models such as the Model of Acidification of Groundwater in Catchments (MAGIC) and MAGIC-With Aggregated Nitrogen Dynamics (MAGIC-WAND).

Air Resources Information System (ARIS)

FLAG 2000 also introduced "Air Synthesis" as an information management and decision-support computer system under development by NPS and FWS. The NPS and FWS have since redesigned and renamed Air Synthesis, now called Air Resources Information System (ARIS). ARIS provides information on air quality related values in NPS and FWS Class I areas, as well as in many NPS Class II areas. Information can be accessed for specific areas or for all units within NPS Inventory & Monitoring (I & M) networks.[8] ARIS identifies specific AQRVs, and provides information on air quality and its effects in parks and wildernesses. ARIS maintains information for all 48 NPS Class I air quality areas and several FWS Class I areas. Information is being developed for the remaining FWS Class I areas, and additional Class II areas. Additional information on ARIS can be found at:

- http://www.nature.nps.gov/air/permits/aris/index.cfm

Information for FWS Class I areas is under development at:

- http://www.fws.gov/refuges/whm/AirQuality/index.html

Natural Resource Information System – Air Module (NRIS-Air)

Publicly available USDA Forest Service Class I and II area information and related resource data can be linked to or found at http://www.fs.fed.us/air. If desired information and data cannot be found, contact any air program manager or specialist at national or regional offices for assistance.

Information from NRIS-Air, including USFS Class I area AQRV information, is available at:

- http://www.fs.fed.us/air

Deposition Effects Models

A number of watershed process models have been developed and tested in an attempt to simulate the effects of S and N on soils, forests, and surface waters. These models are used by FLMs to predict effects from increases in deposition and vary from detailed, compartment models of watersheds to lumped parameter models that do not track different ions through each soil compartment. For a review of models developed under NAPAP see NAPAP 1991.

A commonly applied watershed model is MAGIC. MAGIC was first developed for eastern U.S. watersheds and then extensively tested and validated throughout Europe and North America (Cosby et al. 1985, 1995, 1996). The model was used by NAPAP in its 1990 Integrated Assessment to project surface water chemistry resulting from various deposition scenarios (NAPAP 1991b). In another application in the eastern U.S., MAGIC has been linked with a simple, empirical, dose/response fish model developed at University of Virginia that makes it possible to predict changes in fish productivity based on modeled changes in stream water chemistry.

As a result of NAPAP, there was increased awareness of the potential impacts of inorganic N deposition on watersheds and surface waters. In response, the MAGIC model was updated with a module called With Aggregated Nitrogen Dynamics (WAND). MAGIC-WAND is a process-based model that uses site-specific information on hydrology, soils, and hydrochemistry. The model predicts changes through time in lake or stream chemistry. These time-series of changes in pH and ANC can subsequently be used by FLMs to calculate critical S or N loads for watersheds.

MAGIC-WAND has been extensively tested in the Adirondacks and at watersheds in Maine. For example, the Bear Brook Watershed Manipulation Project uses MAGIC-WAND to predict the effects of experimentally added N and S on a test watershed. MAGIC-WAND has also been applied to watersheds in FLM areas in the Cascades, the Sierra Nevada, the Rocky Mountains, and the Wind River Range in an effort to quantify critical S and N loads to aquatic and terrestrial resources. In the southeastern U.S., MAGIC-WAND is being used under the auspices of the Southern Appalachian Mountains Initiative (SAMI) to predict the effects of future deposition scenarios on FLM areas. Future SAMI modeling efforts will link watershed model results with fish dose/response models. The ultimate goal is to calibrate MAGIC-WAND with landscape level data in order to set regional critical loads.

Other models are also in use. For example, the USFS Rocky Mountain Region recommends using either CALPUFF or AERMOD (or other approved models) to estimate S and N deposition. *The Screening Methodology for Calculating ANC Change to High Elevation Lakes* (USDA Forest Service 2000) summarizes procedures for estimating total deposition of S and N. The document also recommends computations for estimating alkalinity changes in lakes caused by increases in S and N deposition. Another model, the Nutrient Cycling Model (NuCM) has been used in the East to predict the effect of changes in deposition on nutrient concentrations in soils and vegetation.

3.5.6. Recommendations for Evaluating Potential Effects from Proposed Increases in Deposition to an FLM Area (Revised)

FLAG 2000 described a process to help the Agencies and permit applicants assess the total sulfur and/or total nitrogen deposition impacts of proposed new or modified sources.

8. The NPS I & M program consists of over 270 park units organized into 32 networks to conduct long-term natural resource monitoring on park "vital signs," that is, selected physical, chemical, and biological elements and processes of park ecosystems that represent the overall health or condition of the park.

Since that time, the Agencies have refined the concept of using concern thresholds, pollutant exposures, and deposition analysis thresholds in the permit review process. The approaches used by the respective agencies may vary somewhat, but in essence are all similar.

Deposition Analysis Thresholds (DATs)

The NPS and FWS have introduced and developed the concept of Deposition Analysis Thresholds (DATs) to use as screening level values for the additional modeled amount of sulfur and nitrogen deposition within FLM areas from new or modified PSD sources. A DAT is defined as the additional amount of nitrogen or sulfur deposition within an FLM area, below which estimated impacts from a proposed new or modified source are considered negligible. In other words, if the new or modified source has a predicted nitrogen or sulfur deposition impact below the respective DAT, the NPS and FWS will consider that impact to be negligible, and no further analysis would be required for that pollutant. In cases where a source's impact equals or exceeds the DAT, the NPS/FWS will make a project specific assessment of whether the projected increase in deposition would likely result in an "adverse impact" on resources considering existing AQRV conditions, the magnitude of the expected increase, and other factors.

The DATs are based on "naturally occurring deposition" that park and wilderness ecosystems may have experienced prior to anthropogenic influences and are scaled to enable assessment of the impacts of individual sources of air pollution. The DAT established for both nitrogen and sulfur in eastern and western FLM areas and wildernesses is 0.010 and 0.005 kilograms/hectare/year (kg/ha/yr), respectively. More information regarding the sulfur and nitrogen DATs can be found at:

- http://www.nature.nps.gov/air/Pubs/pdf/flag/nsDATGuidance.pdf

While DATs are a tool to assess the impact of a single new source, these levels may not be protective in areas that are already impaired or where there are multiple new sources impacting a single area. The critical load concept, discussed above, may be a more effective tool for assessing cumulative impacts.

Concern Thresholds and Pollutant Exposures

The Forest Service has continued to develop AQRV concern thresholds and pollutant exposure(s) thresholds (for sulfur or nitrogen deposition) that when exceeded may indicate an adverse impact to one or more AQRVs. These thresholds are very similar to the NPS/FWS Deposition Analysis Thresholds (DATs) in that they establish a point below which adverse impacts are not expected. Impacts above the thresholds may or may not cause an adverse impact; depending on current levels of deposition and resource condition. The values for these thresholds vary between FS Class I areas; therefore an applicant will need to check for Class I area-specific thresholds on the following Internet site:

- http://www.fs.fed.us/air/technical/class_1/alpha.php

FLM Response to Potential Deposition Impacts

For a project that exceeds the initial annual emissions over distance (Q/D) screening criteria, the permit applicant should consult with the appropriate regulatory agency and FLM for the affected area(s) to determine if a deposition impact analysis should be done (e.g., expected sulfur and/or nitrogen deposition impacts are above the DAT) or respective concern threshold). For such cases, FLMs request that proponents provide sufficient information for the FLM to evaluate the potential effects of emissions increases on AQRVs. FLMs have provided information to applicants through guidance documents, correspondence, meetings, and phone consultations. This chapter summarizes current information for evaluating new emissions on deposition and sensitive AQRVs and includes recommendations for:

- the types of data, information, and analysis needed before a permit application can be considered complete, including analytical and modeling protocols for a proponent's use in conducting an AQRV impact analysis;
- approaches and sources of appropriate values for estimating wet and dry deposition; and
- permit conditions to mitigate source impacts.

The process begins with the question "Q/D ≤ 10?" as the first level screening criteria (see Figure 7). The next question is whether or not the DAT/concern threshold is exceeded. If not, no adverse impacts are expected. If so, the Agencies will determine if the contextual considerations (see section 4.3) or any refined analyses alleviate any deposition concerns. If not, the Agencies will defer to the FLM to make a case-by-case adverse impact finding. In determining if the proposed action will cause or contribute to an adverse effect to AQRVs, the FLM will consider information on deposition-sensitive AQRVs, deposition loads at which these AQRVs are affected (i.e., critical loads), the current pollutant deposition rates in the area, and the expected impacts from the proposed source. Procedures for estimating the source's impacts are found in 'Estimation of Current and Future Deposition Rates' section of this report. In areas where no information is available, information from a nearby, or ecologically similar area, may be used. An adverse effect may occur if the critical load is exceeded for an area, and the new source impact is above the levels of concern (i.e., DAT/concern threshold). AQRV and critical load information are discussed earlier in this report.

If the available information is insufficient for the FLM to determine if the proposed action will cause or contribute to an adverse effect to AQRVs, the FLM may ask for deposition and deposition effects monitoring and/or

research in the FLM area. If the proposed action will likely cause or contribute to an adverse effect to AQRVs, the FLM may recommend permit conditions that ensure mitigation, including stricter emissions controls and effective emissions offsets. If no mitigation is possible, the FLM may recommend denial of the permit.

Available Deposition Monitoring Data

Atmospheric pollutants are deposited to ecosystems primarily through wet deposition and dry deposition. FLMs participate in national monitoring programs to monitor wet and dry deposition, including the National Atmospheric Deposition Program (NADP) and the Clean Air Status and Trends Network (CASTNet). A 1999 report, "The Role of Monitoring Networks in the Management of the Nation's Air Quality," (CENR, 1999) identified these two networks as being critical for characterizing baseline air quality data in the U.S.

Wet Deposition (Revised)

Wet deposition includes rain, snow, fog, cloud water, and dew. In most FLM areas, rain and snow are the primary contributors to wet deposition. However, in some high elevation areas, fog, cloud water, and dew are significant contributors, as discussed below.

Because rain and snow are the primary constituents of wet deposition at most FLM areas, the FLM generally relies on data from NADP to evaluate wet deposition of pollutants. NADP samplers collect rain and snow and NADP has documented deposition for many years in a nationwide network that currently includes over 220 monitoring

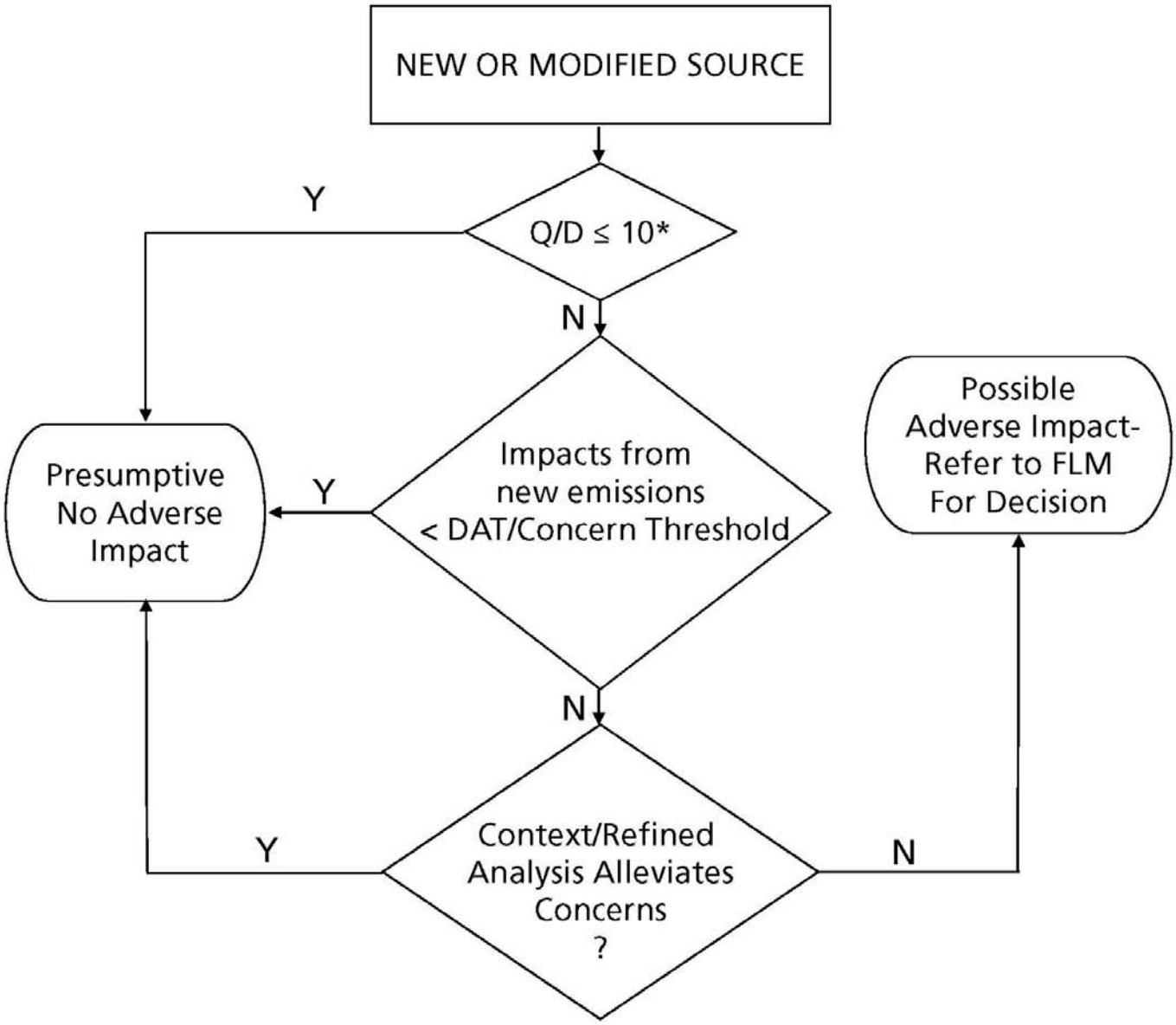


Figure 7. FLM Assessment of Potential Deposition Effects from New Emissions Sources (Revised)
*Q/D test only applies to sources located greater that 50 km from a Class I area.

sites. The network collects data to evaluate spatial and temporal long-term trends in precipitation chemistry. The precipitation at each site is collected weekly and sent to a central analytical laboratory for analysis of hydrogen (acidity as pH), sulfate, nitrate, ammonium, chloride, and base cations, including calcium, magnesium, potassium, and sodium. Data and isopleth maps of pollutant concentrations and deposition are available on the NADP web site at:

- http://nadp.sws.uiuc.edu/

FLMs agree that it is preferable to obtain NADP data from the web site, rather than summarizing wet deposition data in this report. In this way, current data can be easily accessed by FLMs and the public.

Approximately 50 FLM areas have NADP samplers in or immediately adjacent to them. Because some of these areas are classified as wilderness, FLMs install sampling equipment in adjacent non-wilderness areas in order to preserve the wilderness character of the area. Ambient air in these adjacent areas is considered representative of air in the wilderness area.

A number of FLM areas do not have an NADP sampler in or adjacent to them. Where possible, the FLM has identified an NADP site whose data may be used to characterize deposition at the area. Deposition rates generally increase with elevation and deposition in high-elevation areas may be difficult to characterize with data from a lower-elevation NADP site. FLM consultation may be necessary to estimate deposition in these areas.

Areas that experience significant deposition from fog and cloud water or large amounts of snow may need to use alternate sampling methods and data in addition to NADP protocols and NADP data to characterize them. Wet deposition in these areas may need to be sampled with alternate methods, including cloud water samplers and snowpack sampling or estimated by modeling. At sites where such data or modeled estimates are available, they should be used to calculate total deposition. At mountain sites frequented by clouds and fog, deposition from clouds may equal or exceed that from precipitation. Cloud water is generally more acidic and contains higher concentrations of base cations than rain water; therefore, it can contribute significantly to total loadings of S and N (Hemmerlein and Perkins 1992). Various methods have been developed to measure deposition from cloud water. The Mountain Acid Deposition Program (MADPro) used automated cloud water collectors to sample at three high-elevation eastern sites (Anderson et al. 1999). Forests covered by fog for significant periods of time may be especially susceptible to injury from acid deposition. Acidic cloud water has predisposed red spruce in the high elevations of the northeast U.S. Appalachians to winter injury and cumulative impacts with other biotic and abiotic stresses have caused mortality. The contribution of clouds and fog to deposition at high elevations may overshadow both deposition from precipitation and dry deposition (Hidy 1998). The EPA estimated that as a result of cloud cover, high elevation forests might experience four times the amount of total pollutant deposition as lower elevation forests without cloud cover (NAPAP 1991). High elevation lakes are also impacted by fog and clouds, as well as rain and snow. Measurements in high elevation areas that do not include all contributions to wet deposition will result in under-estimates.

Modeling has been used to estimate total wet deposition in some areas. For example, the Southern Appalachian Man and the Biosphere Cooperative (as part of the Southern Appalachian Assessment) has used NADP data, topographical data, and meteorological data to model wet deposition loading at locations in the southeastern U.S.

Dry Deposition (Revised)

Dry deposition includes gases, aerosols and particles. The primary gases involved with N and S deposition are ammonia (NH_3), nitric oxide (NO), nitrogen dioxide (NO_2), nitric acid (HNO_3), and sulfur dioxide (SO_2), while the primary particles are nitrate (NO_3^-), ammonium (NH_4^+), and sulfate (SO_4^{2-}) ions (Hanson and Lindberg 1991). Ammonia, NO, NO_2 and SO_2 are taken up by plants through stomata, while HNO_3, due to its high deposition velocity, is deposited to plant surfaces in addition to being taken up by stomata. Nitrate, ammonium, and sulfate particles deposit to surfaces (Bytnerowicz and Fenn 1996).

Dry deposition is much more difficult to estimate than wet deposition. The estimation of dry deposition rates requires information on the ambient concentrations of pollutants, meteorological data, and information on land use, vegetation, and surface conditions, all of which are site-specific. Because of this site-specificity, it is difficult to spatially extrapolate dry deposition data as is often done for wet deposition data.

In general, FLMs rely on data from CASTNet for estimates of dry deposition in FLM areas (http://www.epa.gov/castnet). CASTNet was developed by EPA, as a result of the Clean Air Act Amendments of 1990, and currently includes over 70 sites. These include a combination of former National Dry Deposition Network sites, Park Research and Intensive Monitoring of Ecosystems Network sites (PRIMENet), and others. Dry deposition is measured at 26 NPS areas and 2 USFS areas. FLMs agree that it is preferable to obtain CASTNet data from the web site, rather than summarizing dry deposition data in this report. In this way, current data can be easily accessed by FLMs and the public.

Other methods for measuring dry deposition are available. For example, information on vertical changes in concentrations of major gases and particles of interest over plant canopies can be used for calculation of deposition of

these compounds to forests and other ecosystems (Hicks et al. 1987). Models, such as "Big-Leaf" (Baldocchi et al. 1987) allow estimating dry deposition to uniform canopies, such as agricultural crops or lowland forests. However, no models have been developed so far for reliable estimates of deposition of gases and particles to forests and other ecosystems in complex mountain terrain (Bytnerowicz et al. 1997). Therefore, no good large-scale estimates of dry deposition are available for western U.S. forests.

Another approach to evaluating dry deposition is net throughfall technique. By measuring concentrations of ions in throughfall (bulk precipitation) and after subtracting concentrations of the same ions in precipitation in an open area, fluxes of ions such as nitrate, ammonium, and sulfate can be calculated. A branch washing technique is similar to the net throughfall approach and is used when no wet precipitation is present. The pre-washed branches are exposed to ambient air for a certain time period and then carefully rinsed with water (Lindberg and Lovett 1985). Information about amounts of nitrate, ammonium and sulfate rinsed from branches of a known surface area, time of exposure, and leaf area index of a given forest stand allow the calculation of fluxes of the measured ions to trees. Adding stomatal uptake of gases (calculated from information on gas concentration and stomatal conductance), and estimates of deposition to other landscape forms (such as soils and rocks) allow for quite reliable estimates of dry deposition at a forest stand level (Bytnerowicz et al. 2000). Such estimates have been made for the subalpine zone of the eastern Sierra Nevada and mixed conifer forests on the western Sierra Nevada and the San Bernardino Mountains (Bytnerowicz and Fenn 1996; Bytnerowicz et al. 1999). Both the net throughfall and branch washing techniques, although providing relatively accurate estimates of deposition to certain ecosystems, cannot be applied to every type of vegetation. These techniques work well for conifers with relatively thick cuticles. For plants with thinner cuticle, extraction of ions from plant interior or transcuticular uptake of deposited ions may not allow for making good estimates of dry deposition to plant surfaces.

Recent developments, such as passive samplers that allow for relatively inexpensive determinations of nitric oxide, nitrogen dioxide, ammonia, nitric acid and sulfur dioxide concentrations, provide some promising opportunities for large-scale estimates of distribution of these pollutants. This, together with information on landscape-level vegetation coverage, leaf area index, and deposition velocity of the monitored pollutants, will allow calculating deposition of the measured gases to various landscape forms. Although this approach would not include deposition fluxes of particulate pollutants, a large portion of dry N and S deposition (gases) would be covered. Information on fluxes of the N and S particulate component (nitrate, ammonium, and sulfate ion concentrations) can be estimated based on their concentrations from annular denuder/filter pack systems or other comparable techniques and literature values of deposition velocities of these ions.

For many FLM areas, detailed site-specific information and monitoring needed for dry deposition measurements are not available. Therefore, the FLM may choose to recommend a reasonable estimate of dry deposition. NAPAP's 1991 summary report concluded that dry deposition of sulfur is 30-60% of the total (wet plus dry) deposition at regionally representative sites; dry deposition of nitrogen is 30-70% of the total (wet plus dry) deposition at regionally representative sites (NAPAP 1991a). An analysis of one year (1991) of NADP, CASTNet, and IMPROVE (Interagency Monitoring of Protected Visual Environments) data from national parks and wildernesses found that wet deposition dominated total deposition in both the East and the West. Dry deposition of sulfur was 20-50% of the total; dry deposition of nitrogen was 30-60% of the total (Hidy 1998). These estimates, and similar ones, have led to the common assumption that dry deposition is approximately 50% of the total deposition. Therefore, for many FLM areas without on-site or nearby representative dry deposition sampling, the FLM may recommend that dry deposition is equal to wet deposition. The FLM recommends this as a "best available estimate," recognizing that in some areas it may result in under- or over-estimating total deposition. Total deposition, which is the sum of wet plus dry deposition, therefore equals twice the wet deposition.

In summary,

Total Deposition = Wet Deposition + Dry Deposition

Or,

Total Deposition = 2 x Wet Deposition (assuming Dry Deposition = Wet Deposition)

There are numerous monitoring stations in or near FLM areas for estimating wet and dry deposition values. For some areas the FLM assumes that dry deposition equals wet deposition, recognizing that this may result in under- or over-estimates of total deposition. Deposition monitoring data and information on the appropriate dry deposition data to use at sites where data are available are included on the respective Agencies web sites referenced previously.

FLMs will continue to participate in monitoring and research to further our understanding of dry deposition dynamics and improve our measurements of dry deposition.

Other Deposition Measurement Methods

Pollutant deposition, particularly in areas where traditional wet and dry deposition sampling is impractical, can also be estimated by other methods. These methods include bulk samplers that collect both wet and dry deposition and snowpack measurements that estimate the total amount of

pollutants in the snow column at the time of maximum snow accumulation. Special methods have also been developed for collecting fog and cloud water (Anderson et al. 1999).

In addition, methods are being developed to estimate dry deposition rates from pollutant concentrations obtained by IMPROVE fine particle samplers. IMPROVE samplers are located at many FLM areas and expanded coverage is planned for 1999.

Modeling Deposition Rates

Deposition from existing sources can be estimated from deposition monitoring data, but contributions to deposition from the proposed source and other sources permitted but not yet operating should be modeled.

Modeling should be done in accordance with recommendations developed by the Interagency Work Group on Air Quality Modeling (IWAQM) Phase 2:

- http://www.epa.gov/scram001/7thconf/calpuff/phase2.pdf

IWAQM provides the procedures that can be used to estimate S and N deposition from a proposed source and other sources permitted but not yet operating. The FLMs propose that these procedures be used to estimate S and N deposition. For S deposition, the wet and dry fluxes of sulfur dioxide and sulfate are calculated, normalized by the molecular weight of S, and expressed as total S. For N deposition, IWAQM recommends that the wet and dry fluxes of nitric acid (HNO_3) and nitrate (NO_3^-) and the dry flux of nitrogen oxides (NO_x) be calculated, normalized by the molecular weight of N, and expressed as total N. In addition, the FLMs agree that wet and dry fluxes of ammonium sulfate ($(NH_4)_2SO_4$) and ammonium nitrate (NH_4NO_3) should be calculated, normalized by the molecular weight of N, and added to the estimate of total N. Therefore, total N deposition is the sum of N contributed by dry and wet fluxes of HNO_3, NO_3^-, $(NH_4)_2SO_4$, and NH_4NO_3 and the dry flux of NO_x.

The FLMs recognize that the ammonia (NH_3) in these compounds is derived from both man-made and natural sources. Free gaseous NH_3 has a high deposition velocity and tends to deposit quickly. However, if sulfates and nitrates (which are primarily man-made) are present in the atmosphere, free NH_3 quickly reacts to form $(NH_4)_2SO_4$ and NH_4NO_3. These compounds, because of their fine particle size and slower deposition velocity than free gaseous NH_3, can be transported long distances and deposited in a FLM area, adding to the total N deposition loading.

An appropriate estimate of ambient free gaseous NH_3 is needed for the modeling analysis. IWAQM refers to Langford et al. (1992), who suggest that typical (within a factor of 2) background values of NH_3 are: 10 parts per billion (ppb) for grasslands, 0.5 ppb for forest, and 1 ppb for arid lands at 20°C. Langford et al. (1992) provide strong evidence that background levels of NH_3 show strong dependence with ambient temperature (variations of a factor of 3 or 4) and a strong dependence on the soil pH. However, given all the uncertainties in NH_3 data, IWAQM recommends use of the background levels provided above, unless better data are available for the specific modeling domain. IWAQM notes that in areas where there are high ambient levels of sulfate, values such as 10 ppb might overestimate the formation of particulate nitrate from a given source, for these polluted conditions. IWAQM further notes that areas in the vicinity of strong point sources of NH_3, such as feed lots or other agricultural areas, may experience locally high levels of background NH_3.

Questions regarding these recommendations should be resolved through consultation with the appropriate FLM and the appropriate State and/or EPA modeling representative. Applicants should provide a modeling protocol to the appropriate FLM prior to conducting modeling analyses.

Estimation of Current and Future Deposition Rates (Revised)

In order to evaluate a proposed source's contribution to total (wet + dry) deposition in a FLM area, it is necessary to first estimate current pollutant deposition rates. The current rate is a result of deposition from all existing natural and anthropogenic sources. FLMs use two approaches to estimating the current rate of deposition. One approach estimates the current rate by averaging data from an appropriate monitoring site for the pollutant of interest, using all years with complete data records. The second, more conservative, approach assumes that the current rate is equivalent to the highest rate for the pollutant of interest in the data record.

The method for estimating future total deposition rates is:

- From the respective Agency web sites, identify available on-site or representative wet and dry deposition data for the FLM area. Wet deposition data can be obtained through NADP (http://nadp.sws.uiuc.edu/). For NPS sites without an NADP sampler, use estimates of total wet nitrogen and total wet sulfur from the Air Quality Estimates for 1999-2003 at http://www.nature.nps.gov/air/Maps/AirAtlas/index.cfm.

  Dry deposition data can be obtained through CASTNet at (http://www.epa.gov/castnet).

  Verify if dry deposition is assumed to equal wet deposition for the site. For high-elevation sites, consult with the FLM to determine if deposition from cloud water, fog, dew, or snowpack should be considered. For sites without on-site data, consult FLM for further guidance.

- After consulting with the FLM, estimate either:

  - the average annual or seasonal wet and dry deposition rates for the appropriate pollutant using all years with complete data records; or
  - the highest annual or seasonal wet and dry deposition rates for the appropriate pollutant using all years with complete data records.
- Calculate current total deposition (wet + dry = total).
- Estimate, using the appropriate dispersion model as described in the 'Modeling Deposition Rates' section above, the proposed source's contribution to future total deposition on an annual or seasonal basis.
- Estimate, using appropriate dispersion model as described in the 'Modeling Deposition Rates' section above, the contribution of any sources permitted but not yet operating to future total deposition and the affect of any enforceable emission reductions. This estimate may be available from the State permitting authority.
- The current pollutant deposition rate plus the proposed source's contribution to deposition plus the contribution from other sources permitted but not yet operating minus credit for enforceable emission reductions equals the future total deposition rate.

Current + Proposed + Permitted (not yet operating) – credit for enforceable reductions = Future Total Deposition

This future total deposition rate for a given pollutant can then be used to determine the potential for adverse effects to AQRVs. If appropriate, the change in deposition rate can be used to estimate changes in pH or ANC in an ecosystem. If the future total deposition rate is expected to cause an adverse effect to AQRVs and/or exceeds the critical load established for a FLM area, the FLM may recommend mitigation. If no critical load has been established for the FLM area, the FLM will use the best information available in determining whether to recommend mitigation.

3.5.7. Summary (Revised)

- Deposition of S and N has the potential to affect terrestrial, freshwater, and estuarine ecosystems on FLM lands.
- The FLM has identified, where possible, AQRVs sensitive to deposition of S and N on FLM lands and the critical loads associated with those AQRVs.
- A proponent of a source of new emissions with the potential to contribute to S or N deposition in an FLM area should consult with the FLM to determine what analyses are needed to assess AQRV effects. The FLM may request a deposition impact analysis, described in detail in this chapter and summarized below.
  - Estimate the current deposition rate to the FLM area. A list of monitoring sites providing data to characterize deposition in FLM areas is included on the respective Agencies web sites.
  - Estimate the future deposition rate by adding the existing rate, the new emissions' contribution to deposition, the contribution of sources permitted but not yet operating, and then subtracting the credit for enforceable emission reductions. Modeling of new, reduced, and permitted but not yet operating emissions' contribution to deposition should be conducted following current EPA modeling guidance.
  - Compare the future deposition rate with the recommended screening criteria (e.g., critical load, concern threshold, or screening level value) for the affected FLM area. A list of documents summarizing these screening criteria, where available, can be found in Appendix G.

    Information for USFS Class I areas is also available at:

    http://www.fs.fed.us/air

    Information for NPS and FWS Class I areas is available at:

    http://www.nature.nps.gov/air/Permits/ARIS/

    Information for FWS Class I areas is under development at:

    http://www.fws.gov/refuges/whm/AirQuality/index.html

    The appropriate FLM should be contacted for additional information.

3.5.8. Web sites for Deposition and Related Information (Revised)

Clean Air Status and Trends Network (CASTNet) dry deposition data:

- http://www.epa.gov/castnet

National Acid Precipitation Assessment Program 2005 Report:

- http://www.esrl.noaa.gov/csd/AQRS/reports/napapreport05.pdf

National Atmospheric Deposition Program (NADP) wet deposition data:

- http://nadp.sws.uiuc.edu/

National Park Service Airweb:

- http://www.nature.nps.gov/air/

Natural Resources Conservation Service, Snow Water Equivalent Information (SNOTEL):

- http://www.wcc.nrcs.usda.gov/snow

Southern Appalachian Mountain Initiative:

- http://www.tva.gov/sami

USDA Forest Service National Air Resource Management Web Site:

- http://www.fs.fed.us/air/

EPA Office of Air and Radiation:

- http://www.epa.gov/oar

EPA, Deposition to Estuaries:

- http://epa.gov/owow/airdeposition/

EPA, STOrage and RETrieval System for Water and Biological Monitoring Data (STORET):

- http://www.epa.gov/storet

U.S. Fish and Wildlife Service Air Quality Branch:

- http://www.fws.gov/refuges/whm/AirQuality/index.html

U.S. Geological Survey, National Water-Quality Assessment (NAWQA) Program:

- http://water.usgs.gov/nawqa

U.S. Geological Survey, Acid Rain Program:

- http://bqs.usgs.gov/acidrain

U.S. Geological Survey, Water Data Storage and Retrieval System (WATSTORE):

- http://water.usgs.gov/owq/data.html

4. Expansion of Discussion of Process for Adverse Impact Determination (New Chapter)

Based on feedback from permit applicants and State permitting authorities, the Agencies are providing a more detailed description of the adverse impact decision making process once a source analysis has raised concerns during a first-level and any subsequent analyses.

If the first-level analysis yields impacts above the defined threshold(s), the applicant may propose to address preliminary FLM concerns directly through proposed emission reductions for the project, or through implementation of other measures to mitigate emission impacts. Alternatively, the applicant may undertake a more refined analysis to potentially alleviate preliminary concerns. Of course, this refined analysis should occur in a time-frame that enables permitting authorities to adhere to their regulatory guidelines.

Additional emission reductions, mitigation proposals, or more refined analysis are not legal requirements. They are options that can be utilized to help alleviate preliminary FLM concerns about emission impacts on Class I areas. Permit applicants can request that FLMs conduct their evaluation based on information provided in the application.

4.1. Background

The FLAG visibility thresholds have been interpreted by some as a one-dimensional or bright line test that inevitably leads to an adverse impact determination. This, however, is not the intent; these screening-levels were envisioned as a "visibility analysis threshold" similar to the newer deposition analysis thresholds (DATs) discussed above for sulfur and nitrogen deposition.

The Agencies want to emphasize that the FLAG report provides criteria as to when the FLMs will definitively not object to, or declare an adverse impact for, a proposed new source. FLAG assures an applicant that, if they conduct their analyses correctly and demonstrate that change in extinction or deposition falls below the specified thresholds, the FLMs will not raise concerns regarding the project. However, the converse does not necessarily apply — a FLAG threshold exceedance does not mean the FLM will certainly find that a project will adversely affect air quality related values. If a threshold is exceeded, the FLMs will consider the factors discussed below and make a project-specific determination as to whether or not the impacts are adverse.



Seney National Wildlife Refuge, Michigan.
Credit: Atlee Hart

4.2. Regulatory Factors

According to the EPA definition of "adverse impact on visibility," the FLM must determine whether the proposed source's predicted impact "interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience" taking into account the "geographic extent, intensity, duration, frequency and time of visibility impairments, and how these factors correlate with (1) times of visitor use of the Federal Class I area, and (2) the frequency and timing of natural conditions that reduce visibility." (40 C.F.R. §51.301).

Considering the regulatory factors is inherent in the first-level modeling exercise. The model describes the geographic area predicted to be impacted. The visibility extinction values describe the intensity of the impact. Similarly, the model provides some level of assessment regarding duration, frequency, and time of impact. A more refined modeling analysis should further inform consideration of these factors. Regarding how these factors correlate with visitor use, the responsibilities of the Agencies include protecting the resources for all visitors. Visitor data show that nearly all Class I areas have some level of visitation each month. Regarding correlation with the frequency and timing of natural conditions that reduce visibility, the first-level modeling analysis will not provide this information directly, but, by using the percentile approach and monthly relative

humidity values, the Agencies have attempted to provide a reasonable approach to addressing weather impacts.

Similarly, if the sulfur or nitrogen DAT is exceeded, or if high ozone levels are anticipated, the FLMs should determine if those impacts would adversely affect sensitive AQRVs. This adverse impact determination should be made on a project-specific basis and will be largely driven by management objectives for the area.

4.3. Contextual Considerations

The Agencies recognize that the context within which new source permitting occurs is shifting. Many older major stationary sources will be installing pollution controls over the next 10 to 15 years (e.g., in response to the Regional Haze Rule). New motor vehicle emission and fuel standards will reduce tailpipe pollution from mobile sources gradually, but significantly, over a similar time frame. States are developing visibility protection plans that ensure "reasonable progress" toward natural conditions, pursuant to the EPA's Regional Haze Rule. These plans will be reviewed and revised every five to ten years, and thus provide a mechanism for revisiting sources as better technology becomes available or as otherwise needed to maintain progress toward visibility goals. The location and effect of pending pollution control programs on specific Class I areas remains somewhat uncertain; however, the Agencies recognize and appreciate that significant emission reductions are anticipated, especially in the eastern U.S.

As part of the discussions with permitting authorities or permit applicants when screening level thresholds are exceeded, the Agencies will consider contextual information, including, for example:

- Current pollutant concentrations and AQRV impacts in the Class I area
- Air quality trends in the Class I area
- Emission changes that have occurred or would occur (i.e., enforceable) by the time the new source begins operation
- Whether there are approved SIPs that account for new source growth and demonstrate attainment of national ambient air quality standards and "reasonable progress" toward visibility goals
- The expected useful life of the source
- The stringency of the emission limits (e.g., Best Available Control Technology)
- Other considerations such as options put forth by the applicant that would produce ancillary environmental benefits to AQRVs (e.g., reductions in toxic air contaminants, pollution prevention investments)
- Comments received from the public or other agencies during the comment period prior to issuing the permit.

4.4. Preliminary Adverse Impact Concerns

After considering the regulatory factors and contextual considerations listed above, the Agencies, in consultation with the FLM, will evaluate, on a project-specific basis, whether the evidence supports a finding that the new source would possibly cause or contribute to an adverse impact on air quality related values. If so, the Agencies will notify the permit applicant and the permitting agency and provide the permit applicant the opportunity to consider mitigation strategies that will alleviate the potential adverse impact concerns. These strategies may include:

- Obtaining emission offsets for pollutants that cause or contribute to the potential adverse impacts on Class I area resources;
- Reducing emission rates through more stringent pollution control technology or operational or design changes; and
- Monitoring or special studies that increase understanding of how Class I area resources or visitors are affected by air pollution, which may serve as a basis for revisiting permit conditions in future years. (Note: monitoring and study alone does not constitute mitigation.)

Again, proposing any such mitigation strategy is voluntary. Nevertheless, if the FLMs deem a proposed mitigation strategy as adequate to protect AQRVs, and the mitigation strategy is made enforceable via the PSD permit or some other mechanism, the FLM will not make an adverse impact finding with respect to the issues addressed by the mitigation strategy.

4.5. Adverse Impact Determination

If an applicant is unable or unwilling to implement an appropriate mitigation strategy to alleviate potential adverse impact concerns, the FLM will determine whether or not the potential impacts of the project as proposed should be formally deemed adverse to air quality related values in the affected Class I areas. If the FLM concludes that there are potential adverse impacts, he will inform the permitting authority of this decision.

Historically, the FLMs have made adverse impact findings for less that one percent of the permit applications that the Agencies review. In those rare cases, the FLMs will strive to provide the permitting authority with an ample technical and policy/management-related foundation, including a discussion of the analysis results and the regulatory and contextual factors discussed above. The FLMs' ability to provide this foundation will depend on the completeness and adequacy of information provided by the permit applicant. Where information is lacking, or uncertain, the FLMs will err on the side of protecting air quality related values.



Denali National Park and Preserve, Alaska.
Credit: National Park Service/Trey Simmons.

5. Future FLAG Work

5.1. Implementing FLAG Recommendations (Revised)

FLAG participants believe that the recommendations in this revised document should be implemented as soon as possible. Therefore, an attempt has been made to present thorough and clear information on the processes that will be used to protect and improve AQRVs in FLM areas.

Many of the issues and recommendations discussed herein are complex and require specialized knowledge. Consequently, State agencies and others who intend to use this information in NSR/PSD permitting, land planning and use, and other activities, may want or require further guidance and implementation assistance. The Agencies anticipate that much of this guidance and assistance will be provided locally through established formal and informal links between FLMs, States, EPA and others. For example, the Agencies intend to provide further information through their respective web sites, and through participating in related training sessions and/or workshops.

5.2. Phase I Updates (Revised)

This revised *FLAG Phase I Report* is intended to clearly state FLM positions regarding NSR/PSD as it currently exists. As the FLMs learn more about how to better assess the health and status of AQRVs, and as EPA produces new modeling tools, the FLAG report may be revised again. Any such revisions to the report will be announced on the Agencies' web sites.

5.3. Phase II Tasks (Revised)

FLAG Phase I focused on issues that could be resolved relatively quickly, without extensive research or the collection of new data. The FLMs envisioned a Phase II that would address the more complex issues and concerns, including those that may require additional data collection. Unfortunately, lack of available resources has prevented the Agencies from embarking on a formal FLAG Phase II process. Nevertheless, the Agencies continue to gather effects-based information as part of their ongoing resource protection responsibilities. The new information gathered since FLAG 2000 is reflected in this revision. As the Agencies generate additional data or information, they will make that available to interested parties via their respective web sites.

Appendix A: Glossary

The list below contains definitions for some of the terms used in the *FLAG Phase I Report*. These terms are defined in the sense that they relate to the work of the Federal Land Managers (FLMs) in protecting air resources.

For terms whose definition is lengthy or complex, the associated *Code of Federal Regulations* (CFR) section or other reference is cited.

Air Quality Related Value (AQRV). A resource, as identified by the FLM for one or more Federal areas, that may be adversely affected by a change in air quality. The resource may include visibility or a specific scenic, cultural, physical, biological, ecological, or recreational resource identified by the FLM for a particular area.

Adverse Impact on an AQRV. An unacceptable effect, as identified by an FLM, that results from current, or would result from predicted, deterioration of air quality in a Federal Class I or Class II area. A determination of unacceptable effect shall be made on a case-by-case basis for each area taking into account existing air quality conditions. It should be based on a demonstration that the current or predicted deterioration of air quality will cause or contribute to a diminishment of the area's national significance, impairment of the structure and functioning of the area's ecosystem, or impairment of the quality of the visitor experience in the area.

Adverse Impact on Visibility. Visibility impairment which interferes with the management, protection, preservation, or enjoyment of a visitor's visual experience of a Federal Class I or Class II area. This determination must be made on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency and time of visibility impairments, and how these factors correlate with (1) times of visitor use of the Class I area, and (2) the frequency and timing of natural conditions that reduce visibility. This term does not include effects on integral vistas. [40 CFR §51.301(a)]

Absorption. The process by which incident light is removed from the atmosphere and retained by a particle.

Absorption Coefficient. A number that is proportional to the "amount" of light removed from a sight path by absorption per unit distance.

Acidification. The decrease of acid neutralizing capacity in water or base saturation in soil caused by natural or anthropogenic processes.

Aerosol. A mixture of microscopic solid or liquid particles in a gaseous medium. Smoke, haze, and fog are aerosol examples.

Airshed. A geographic area that, because of topography, meteorology, and/or climate, is frequently affected by the same air mass.

AOT40. Sum of all hourly average concentrations after subtracting 40 ppb from each hourly value.

BACT (Best Available Control Technology). The control level (or control measures) required for sources subject to PSD. (See 40 CFR §52.21(b)(12), or 40 CFR §51.166(b)(12)).

Class I Area. As defined in the Clean Air Act, the following areas that were in existence as of August 7, 1977: national parks over 6,000 acres, national wilderness areas and national memorial parks over 5,000 acres, and international parks.

Critical Load. The quantitative estimate of an exposure to one or more pollutants below which significant harmful effects on specified sensitive elements of the environment do not occur according to present knowledge.

Cumulative. The impact on an AQRV resulting from the total pollutant loading from all sources including the contributing effects of known and reasonably foreseeable new and modified sources of air pollution. A single source may cause individually minor, but cumulatively significant, effects on AQRVs.

Damage. Any reduction in the intended use or value of a biological or physical resource. For example, economic production, ecological structure or function, aesthetic value, or biological or genetic diversity that may be altered by a pollutant.

Deposition Analysis Threshold. A screening threshold developed by NPS and FWS that defines the additional amount of nitrogen or sulfur deposition within an FLM area, below which estimated impacts from a proposed new or modified source are considered negligible.

Emission Offset. A Federally enforceable reduction in emissions from an existing source that mitigates the impacts of a proposed new or modified source on AQRVs, PSD increments, and/or NAAQS. Also, Federally enforceable reductions in actual emissions from existing sources in a nonattainment area such that the total allowable emissions from a new or modified source and existing sources will be sufficiently less than the total emissions from existing sources before the application for a permit to construct so as to represent reasonable further progress towards attainment of the NAAQS. (See 42 U.S.C. § 7503(a)(1)(A))

Extinction. The attenuation of light due to scattering and absorption as it passes through a medium.

Fugitive Emissions. Emissions which do not pass through a stack, chimney, vent, or other functionally equivalent opening.

Federal Land Manager (FLM). The Secretary of the Department with authority over such lands. [40 CFR §51.166(b)(24)] The FLM for the Department of the Interior has been delegated to the Assistant Secretary for Fish and Wildlife and Parks; the FLM for the Department of Agriculture has been delegated to the Forest Service, and has been redelegated to the Regional Forester or individual Forest Supervisor.

Flux. Gaseous uptake into plant tissue.

Green Line. The total pollutant loading (contributions from existing and proposed sources) below which there is a very high degree of certainty that no AQRV will be adversely affected.

Haze. An atmospheric aerosol of sufficient concentration to be visible. The particles are so small that they cannot be seen individually, but are still effective attenuating light and reducing visual range.

Hydrocarbons. Compounds containing only hydrogen and carbon. Examples: methane, benzene, and decane.

Hygroscopic. Readily absorbing moisture, as from the atmosphere.

Injury. Any physical or biological response to pollutants, such as a change in metabolism, reduced photosynthesis, leaf necrosis, premature leaf drop, or chlorosis.

LAER (Lowest Achievable Emissions Rate. The control level required of a source subject to nonattainment review. (See 40 CFR §51.165(a)(1)(xiii))

Limit of Acceptable Change. The amount of change that could occur without significantly altering an AQRV or sensitive receptor.

Micrometer. A unit of length equal to one millionth of a meter; the unit of measure for particle size.

Mie Theory. A complex mathematical model that allows the computation of the amount of energy (light) scattered by spherical particles.

N100. Number of hourly average concentrations ≥100 ppb.

Natural Conditions. Conditions substantially unaltered by humans or human activities. As applied in the context of visibility, natural conditions include naturally occurring phenomena that reduce visibility as measured in terms of light extinction, visual range, contrast, or coloration.

Natural Visibility Conditions. Visibility conditions attributable to Rayleigh scattering and aerosol associated with natural processes.

Nephelometer. An instrument that measures the amount of light scattered.

Nitrates. Those gases and aerosols that have origins in the gas-to-aerosol conversion of nitrogen oxides, e.g., NO_2 ; of primary interest are nitric acid and ammonium nitrate. Ammonium nitrate is very hygroscopic so its contribution to visibility impairment is magnified in the presence of water vapor.

Nitrogen Dioxide (NO_2). A gas consisting of one nitrogen and two oxygen atoms It absorbs blue light and therefore has a reddish-brown color associated with it.

Nonattainment Area. An area designated by the EPA Administrator pursuant to Section 107(d) of the Clean Air Act as having air quality which does not meet one or more National Ambient Air Quality Standard (NAAQS). For a list of nonattainment areas, see 40 CFR Part 81, Subpart C.

Oxidant Stipple. Small brown or black interveinal necrotic lesions on the adaxial surface of leaf tissue that can be attributed to exposure to ozone.

Phytotoxic. Poisonous to plants.

Post-Construction Monitoring. Monitoring required as a permit condition that the permitting authority considers necessary to determine the effect emissions from a stationary source may have, or are having, on the air quality or on the AQRVs of an area. Such monitoring includes both "ambient" monitoring and "AQRV" monitoring and may involve short-term and long-term measurements made at locations representative of the greatest expected impacts.

PSD Increments. The maximum increases in ambient pollution concentrations allowed over baselines concentrations. See 40 CFR §51.166 (c) for increments for specific pollutants.

RACT (Reasonable Available Control Technology). The lowest emissions limit that a particular source can meet by the application of control technology that is reasonably available considering technological and economic feasibility.

Rayleigh Scattering. The scattering of light by particles much smaller than the wavelength of the light, e.g., molecular scattering in the natural atmosphere.

Reconstructed Extinction. Extinction estimate that results from summing up the product of the mass of each measured particle species and the appropriate absorption or extinction coefficient.

Red Line. The total pollutant loading (contributions from existing and proposed sources) at which there is a very high degree of certainty that at least one AQRV will be adversely affected.

Regional Haze Visibility Impairment. Any humanly perceptible change in visibility (light extinction, visual range, contrast, coloration) from that which would have existed under natural conditions, caused predominantly by a combination of many sources from, and occurring over, a wide geographic area.

Re-opener. A permit condition that requires the permitting authority, at a specified time after permit issuance, to review and revise, if necessary, the permit based on new information such as the findings from post-construction monitoring, updated emissions inventories, updated modeling, research, or information on air pollution effects to terrestrial, aquatic, and visibility resources.

Scattering. An interaction of a light with an object (e.g., a fine particle) that causes the light to be redirected in its path.

Scattering Coefficient. Measure of the ability of particles to scatter light; measured in number proportional to the "amount" of light scattered per unit distance.

Screening Level or Screening Level Value (SLV). The concentration or dose of air pollution below which estimated impacts from a proposed new or modified source are considered insignificant. The SLV is dependent on existing air quality and on the condition of the AQRV of concern.

Sensitive Receptor. The AQRV, or part thereof, that is the most responsive to, or the most easily affected by the type of air pollution in question. For example, at Great Smoky Mountains National Park, spruce-fir forest is a sensitive receptor of the AQRV flora.

Sensitive Receptor Indicator. A measurable physical, chemical, biological, or social (e.g., odor) characteristic of a sensitive receptor. For example, for the sensitive receptor, Crater Lake, water clarity is a sensitive receptor indicator.

Stationary Source. A source of pollution that is well defined, such as the smokestack of a coal-fired power plant or smelter.

Sulfates. Those aerosols that have origins in the gas-to-aerosol conversion of sulfur dioxide; of primary interest are sulfuric acid and ammonium sulfate. Sulfuric acid and ammonium sulfate are very hygroscopic so their contribution to visibility impairment is magnified in the presence of water vapor.

Sulfur Dioxide (SO_2). A gas consisting of one sulfur and two oxygen atoms. Of interest because sulfur dioxide converts to an aerosol.

SUM00. The sum of all hourly average concentrations above 0 ppb.

SUM06. The sum of all hourly average concentrations at or above 60 ppb.

Target Load. The acceptable concentration or dose of an air pollutant that provides a reasonable margin of safety below the critical load. The target load should be achievable under existing conditions.

Transmissometer. An instrument that measures the amount of light extinction over a fixed, specified path length.

Visibility Impairment. Any humanly perceptible change in visibility (visual range, contrast, coloration) from that which would have existed under natural conditions. [40 CFR §51.301(x)]

Visual Range. The distance at which a large black object would just disappear from view.

Volatile Organic Compound (VOC). Any compound of carbon, except those excluded by EPA that participates in atmospheric photochemical reactions. (See 40 CFR §51.100(s))

W126. An ozone index that multiplies each specific concentration by a sigmoidal weighted function, then sums all values. $Wi = 1/[1 + Me^{-(A \times Ci)}]$, where M and A are constants 4403 and 126 ppm^{-1}, respectively, w_i is the weighting factor for c_i, and c_i is concentration in ppm.

Appendix B: Legal Framework for Managing Air Quality and Air Quality Effects on Federal Lands

Introduction

The regulation of air pollution sources has clearly been delegated to EPA, and as applicable, the States. However, Federal Land Managers (FLMs) have the responsibility to protect the particular values of the lands over which they have jurisdiction, to the extent they have been delegated the authority, from the adverse impacts of activities inside and outside these areas.

This Appendix sets out the basic legal authorities and responsibilities with which the FLMs comprising FLAG must comply, in addition to those authorities which they can utilize to protect AQRVs on public lands.

For the purposes of this Appendix only, the term "public lands" is defined to include units of the National Park, National Wildlife Refuge, and National Forest Systems.

Agency Organic Acts

Department of the Interior: National Park Service (NPS):

This Organic Act is very specific in that it mandates national park unit managers:

[T]o conserve the scenery and the natural and historic objects and wild life therein and to provide for the enjoyment of the same in such manner and by such means as will leave them unimpaired for the enjoyment of future generations.

16 U.S.C. §1(1997); and

[T]he authorization of activities shall be construed and the protection, management, and administration of these areas shall be conducted in light of the high public value and integrity of the National Park System and shall not be exercised in derogation of the values and purposes for which these various areas have been established, except as may have been or shall be directly and specifically provided for by Congress.

16 U.S.C. § 1a-1 (1997)

Department of the Interior: Fish and Wildlife Service (FWS):

With respect to National Wildlife Refuge System lands (Refuge System lands under the jurisdiction of the United States Fish and Wildlife Service (FWS)), FWS managers are required to manage Refuge System lands so to:

[E]nsure that the biological integrity, diversity, and environmental health of the System are maintained for the benefit of present and future generations of Americans.

16 U.S.C. §668dd(a)(4)(B)(1997)

Department of Agriculture: Forest Service (Forest Service)

National Forest System lands are defined as:

[A]ll National Forests reserved or withdrawn from the public domain of the United States, all national forests acquired through purchase, exchange, donation, or other means, all national grasslands and land utilization projects...and all lands waters, and other interests administered by the Forest Service.

16 U.S.C. §1609(a)(1997)

The Forest Service's Organic Administration Act of 1897 directs the Secretary of Agriculture to:

[M]ake provisions for the protection against destruction by fire and depredations upon the public forests and national forests...

16 U.S.C. Sec. §551(1997)

The National Forest units are managed consistent with Land and Resource Management Plans (LRMPs) under the provisions of the National Forest Management Act (NFMA). 16 §U.S.C. 1604 (1997). Any measures addressing AQRVs on National Forest System lands will be implemented through, and be consistent with, the provisions of an applicable LRMP or its revision (16 U.S.C. §1604(i)).

The Secretary of Agriculture is required by law to prepare a Renewable Resource Assessment by 1979, and every 10 years thereafter. By law this Assessment is required to address:

- A description of Forest Service programs in research, cooperative programs and management of the National Forest System, their relationships, and the relationships of these programs and responsibilities to public and private activities; and
- An analysis of the potential effects of global climate change on the condition of renewable resources on the Forests and rangelands of the United States; and
- An analysis of the rural and urban forestry opportunities to mitigate the buildup of atmospheric carbon dioxide and reduce the risk of global climate change.

16 U.S.C. §1601(a) (1997)

In addition, the Secretary of Agriculture is required to prepare and transmit to the President, a Renewable Resource Program (the Program) every 5 years. This Program must include program recommendations which recognize the fundamental need to protect, and where appropriate,

improve the quality of ... air resources. 16 U.S.C. §1602(5)(C).

The Forest Service's implementing regulations for NFMA are found at 36 C.F.R. §219 et seq. LRMPs are, in part, specifically based on:

[R]ecognition that the National Forests are ecosystems and their management for goods and services requires an awareness and consideration of the interrelationships among plants, animals, soil, water, air, and other environmental factors within such ecosystems.

36 C.F.R. §219.1(b)(3)

The Wilderness Act. 16 U.S.C. §1131 (1997)

AQRVs in Wilderness areas may receive further protection by the language of the Wilderness Act itself which states:

Wilderness areas... shall be administered for the use of the American people in such a manner as will leave them unimpaired for future use and enjoyment as wilderness .... (16 U.S.C. Sec. §1131).

For Wilderness Areas in the National Forest System, the Act's implementing regulations are found at 36 C.F.R. §293. These Wilderness Areas shall be administered:

...[For] such other purposes for which it may have been established in such a manner as to preserve and protect [their] wilderness character. In carrying out such purposes, National Forest Wilderness resources shall be managed to promote, perpetuate, and, where necessary, restore the wilderness character of the land...

36 C.F.R. §293.2 (1997)

The Clean Air Act, 42 U.S.C. §7401 et seq.

Because of a perceived need for national and regional air quality research to support State programs, Congress passed its first federal air quality initiative in 1955. (Air Pollution Control Act of 1955, Ch. 360, 69 Stat. 322). In response to increasing harm to public health and welfare and to inadequate controls and enforcement, Congress has slowly but steadily expanded and refined the law, now known as the Clean Air Act (CAA), to cover more types of pollutants and emitters; e.g., stationary and mobile sources of pollution. These efforts have culminated in the 1990 Amendments to the CAA, which represent the most comprehensive and detailed set of measures to date to both prevent and curtail air pollution.

The declaration of purpose, as revised in 1990 states in part:

The purposes of this subchapter are: to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population.

42 U.S.C. § 7401(b)(1); and

A primary goal of this Act is to encourage or otherwise promote reasonable Federal, State, and local government actions, consistent with the provisions of this Act, for pollution prevention.

42 U.S.C. §7401(c)

The CAA provides an additional legal framework for FLMs to preserve and protect AQRVs from pollution sources emanating both within and outside National Park, Forest, and Refuge boundaries.

National Ambient Air Quality Standards (NAAQS) and State Implementation Plans (SIPs):

The CAA establishes a regulatory program with the goal of achieving and maintaining "national ambient air quality standards" (NAAQS) through state or, if necessary, federal implementation plans (SIPs or FIPs).[1]

The U.S. Environmental Protection Agency (EPA) is charged with promulgating:

- "primary" NAAQS for "criteria" pollutants "to protect the public health," allowing an adequate margin of safety;" and
- "secondary" NAAQS "to protect the public welfare from any known or anticipated adverse effects associated with the presence of such air pollutant in the ambient air."[2]

The above secondary standards may help protect public land AQRVs.[3] To date, EPA has promulgated NAAQS for six criteria pollutants: sulfur dioxide, particulate matter, nitrogen dioxide, carbon monoxide, ozone and lead. In 2006, EPA issued revised, and more stringent NAAQS for "fine particulate matter." In 2008 EPA revised the ozone standard, to address human health and welfare concerns. In 2010, EPA promulgated one-hour standards for nitrogen dioxide and sulfur dioxide. However, EPA openly acknowledged that these revised NAAQS were not fully adequate to protect the above "secondary" values, in particular those sensitive AQRVs on public lands. EPA proposed further revisions to the primary and secondary ozone standards in January 2010 and is currently developing a proposal for secondary NO_x and SO_x standards that are intended to address aquatic acidification due to acid deposition.

Prevention of Significant Deterioration (PSD):

The CAA, as amended in 1977, includes the following major purposes regarding the "prevention of significant deterioration" (PSD) provisions:

[T]o protect public health and welfare from any actual or potential adverse effect . . . from air pollution . . .

notwithstanding attainment and maintenance of all national ambient air quality standards.

42 U.S.C. § 7470(1)

[T]o preserve, protect, and enhance the air quality in national parks, national wilderness areas, national monuments, national seashores, and other areas of special national or regional natural, recreational, scenic, or historic value.

42 U.S.C. §7470(2)

The PSD section provides some protection for park and wilderness AQRVs through establishment of ceilings on additional amounts of air pollution over baseline levels in clean air areas (increments). It requires EPA or the State to provide to the FLM notice of any proposed major emitting facility[4] whose emissions may affect a Class I area (42 U.S.C. §7475(d)(2)(A), and also by charging:

[T]he Federal Land Manager[1] and the Federal official charged with direct responsibility for management of such lands with "an affirmative responsibility to protect the air quality related values (including visibility) of any such lands within a class I area and to consider, in consultation with the Administrator, whether a proposed major emitting facility will have an adverse impact on such values.

42 U.S.C. §7475(d)(2)(B).

Class I areas include national parks larger than 6,000 acres and national wilderness areas and national memorial parks which exceed 5,000 acres, in existence on August 7, 1977. The 1990 Amendments provided that subsequent additions to the boundaries of such areas are also Class I areas. Currently, 48 areas in the National Park system, 21 Refuge System units, and 88 areas under the administration of the Forest Service are designated as Class I.

Under the PSD provisions and implementing regulations (40 C.F.R. §51.166(p)), for Class I areas, once baseline concentrations come under review by submission of a PSD preconstruction permit application for a major new or modified emissions source, only the smallest increment of certain pollutants — sulfur dioxide, nitrogen oxide and particulate matter — may be added to the air by the proposed new source, and other "increment consuming" sources.

Under the PSD provisions a FLM has several tools he/she may use to protect AQRVs.

A state may not issue a PSD permit to allow construction or modification of a major emitting facility when the applicable Federal Land Manager files a notice alleging the facility may cause or contribute to a change in the Class I area's air quality and by identifying the potential adverse impact of such a change, unless:

The facility owner demonstrates that the facility's emissions of particulate matter, sulfur dioxide, and nitrogen oxides will not cause or contribute to concentrations which will exceed the maximum allowable increases for that Class I area.

42 U.S.C. §7475(d)(2)(C)(i)(paraphrased) and 42 U.S.C. §7476.

Even if no increment violation is predicted,

[T]he state may not issue a PSD permit, if the Federal Land Manager demonstrates to the satisfaction of the State that the emissions from such facility will have an adverse impact on the air quality-related values (including visibility) of Class I lands.

42 U.S.C. §7475(d)(2)(C)(ii)(paraphrased)

Neither the CAA nor the implementing regulations specify criteria for the FLM to "satisfy" state permitting agencies. Consequently, some states have taken a liberal view of their discretion to reject an FLM's adverse impact determination. However, EPA's Environmental Appeals Board (the Board) has ruled that state discretion in rejecting a FLM's finding of adverse impacts is not "unfettered" (see the Board's decisions regarding the permit appeals for the Old Dominion Electric Cooperative and Hadson Power projects in Virginia). Nevertheless, the appropriate role of the FLM in the PSD permit process was addressed in EPA's 1996 proposed New Source Review Reform regulations. The final regulations have not yet been promulgated.

Visibility Protection. Subpart II, 42 U.S.C. §7491 et seq. (1997)

The Visibility portion of the CAA:

"... [D]eclares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from man made air pollution."

42 U.S.C. §7491(a)(1).

To help carry out this goal, the Secretaries of the Interior and Agriculture are charged with identifying Class I areas where visibility is an important value. EPA is charged with reporting to Congress on methods to implement the national goal and with promulgating regulations to ensure reasonable progress toward meeting the goal.

In 1980, EPA issued enforceable regulations for visibility impairment "reasonably attributable" to a specific source or small group of sources. In particular, major stationary sources emitting any pollutant which may "reasonably be anticipated to cause or contribute to any impairment of visibility" is required to install best available retrofit technology (BART). In addition, in April 1999 EPA promulgated final regulations addressing regional haze.

The regional haze rule protects air quality in Class I areas by requiring States to plan to achieve "natural" visibility conditions over a 60-year time frame.

The 1990 Amendments added a new section on visibility, which authorizes EPA in conjunction with NPS and other federal agencies, to conduct visibility research and to evaluate clean air corridors and emissions sources and source regions causing visibility impairment in Class I areas. In this regard, EPA was required to establish the Grand Canyon Visibility Transport Commission (GCVTC) by 1991 and consider the recommendations GCVTC would make (42 U.S.C. §7492(f). NPS, FS, FWS, and BLM played a vital role in the work of the GCVTC and committees in an effort to improve air quality in the Grand Canyon and other parks and wilderness areas in the "Golden Circle" on the Colorado Plateau.

As part of the visibility protection process, states are required to promulgate a plan to prevent any future, and remedy any existing impairment of visibility in Class I areas... 40 C.F.R. §51.300 (1997). EPA has defined "visibility impairment" as:

[A]ny humanly perceptible change in visibility (visual range, contrast, coloration) from that which would have existed under natural conditions.

40 C.F.R. §51.301(x)(1997).7

However, EPA has promulgated its visibility regulations to allow FLMs to use their existing authorities to address "visibility impairment" (rather than "significant impairment") so that "the affected Federal Land Manager may certify to the State, at any time, that there exists impairment of visibility in any mandatory Class I Federal area." 40 C.F.R. §51.302(c).

Nonattainment Areas, 42 U.S.C. §7501 et seq.:

Areas that have failed to meet NAAQS for one or more criteria pollutants are designated as "nonattainment" areas. Under the 1990 Amendments, Congress provides for further classification of nonattainment areas based on severity of the nonattainment and availability and feasibility of appropriate pollution control measures and for a compliance schedule ranging from 1993 in marginal nonattainment areas to 2010 for Los Angeles.

The 1990 Amendments authorize EPA to issue control technique guidance documents (CTGs) covering a variety of topics, such as control of idling vehicles and voluntary removal of pre-1980 model year light duty vehicles (cash for clunker programs). (42 U.S.C. §7408.) EPA is authorized to issue CTGs, in lieu of regulations, to reduce "volatile organic compounds" (VOC) emissions from any consumer or commercial product. (42 U.S.C. §7511b.)

Proposed new or modified major stationary sources within nonattainment areas are required to meet emissions limits based on "lowest achievable emission rate" technology (LAER) and may be constructed only if their emissions are sufficiently offset by reductions in emissions from other sources. The 1990 Amendments also require analysis of alternative sites, sizes, production processes, and control techniques and a finding that the benefits of the source outweigh its environmental and social costs. (42 U.S.C. §7501-15.)

General

CAA Subchapter III 42 U.S.C. §7601 et seq. contains definitions, requirements for reports to Congress, authorizations for appropriations, and procedures for EPA rule making and judicial review. Citizen suits are authorized: 1) against EPA for failure to perform a nondiscretionary duty under the CAA, or 2) against others for alleged violations of an emission limitation, standard, or order. (42 U.S.C.§7601 et seq.)

Acid Deposition

The 1990 Amendments add Title IV, which contains requirements for electric utilities to reduce emissions associated with acid rain. To reduce the adverse effects of acid deposition, Title IV requires a reduction in annual emissions of sulfur dioxide of ten million tons from 1980 emission levels and a reduction of nitrogen oxides emissions of approximately two million tons from 1980 emission levels, in the 48 contiguous states and the District of Columbia. (42 U.S.C. §7651.) The Title creates a system of market-based emission allowances, which can be traded among sources. See (42 U.S.C. §7651a-o.)

Operating Permits

The 1990 Amendments add Subchapter V, 42 U.S.C. §7661 et seq., which establishes a nation-wide permit program for existing stationary sources. Permit requirements will include emission limitations. EPA may veto state permits, which do not comply with provisions of the CAA. (42 U.S.C. §7661a-f.)

Conformity, 42 U.S.C. §7506 (1997)

(Paraphrased) No federal agency may engage in, support in any way,... license or permit, or otherwise approve any activity which does not conform to an approved state (or federal) implementation plan. Conformity shall be an affirmative responsibility of the head of each agency. Conformity means:

- Conforming to the SIP's purpose of eliminating or reducing the number of NAAQS violations;
- That any such activities will not:
  - Cause or contribute to new violations in any area; or

- Increase the frequency or severity of any existing standard violation...

EPA, in its "criteria and procedures" for implementing "conformity" has decided that only those activities that "a federal agency can practicably control, and will maintain control over due to a continuing program responsibility" are subject to same. 40 C.F.R. §93.152.

Although required to comply with the conformity provisions (42 U.S.C. §7618(1997)), the FLM cannot use these provisions to protect AQRVs from adverse impacts from off site sources.

Impact on Federal Land Managers

The CAA reinforces the FLMs' Organic Act and Wilderness Act roles as protectors of AQRVs on public lands.

The CAA also imposes on FLMs an obligation to comply with the Act's many provisions regarding the abatement of air pollution to the same extent as any private person (42 U.S.C. §7418).

Thus, under various authorities, FLMs are responsible for protecting AQRVs within their respective unit boundaries and taking appropriate action to do so, when reviewing emission sources both within units, and in proximity to unit boundaries.

FLMs, under the CAA, have an affirmative responsibility for protecting AQRVs (including visibility) in reviewing proposed PSD permits. However, because of the uncertainty involved in "satisfying" State permitting agencies in the PSD process, and the appropriate delegated role for FLMs in non-PSD situations, the existing framework may provide an inadequate means for FLMs to protect AQRVs from adverse impacts caused by sources outside unit boundaries.

Endnotes

1) Clean Air Act, 42 U.S.C. §7401-7671q (as amended 1990).

2) *Clean Air Deskbook*, The Environmental Law Reporter, Environmental Law Institute, 1992.

3) *Managing National Park System Resources: A Handbook on Legal Duties, Opportunities, and Tools*, Chap. 4 "The Clean Air Act" by Molly Ross at pp. 51-65, The Conservation Foundation, 1990.

4) *Atmospheric Environment* Vol. 27B, No. 1, "The 20-Year History of the Evolution of Air Pollution Control Legislation in the U.S.A." by Richard H. Schulze at pp. 15-25., 1993

5) Wilderness Act of 1964, 16 U.S.C. §1131 et seq, P.L. 577, 78 stat 890 as amended.

6) *The Principal Laws Relating to Forest Service Activities*, USDA - Forest Service ISBN 0-16-041927-1, 1993

7) Organic Administration Act of 1897, 16 U.S.C. §473-475, §477-482, §551.

Appendix C: General Policy for Managing Air Quality Related Values in Class I Areas

Most Federal Land Manager (FLM) enabling legislation and regulations developed to implement Federal Laws do not directly address air quality, or air pollution effects on Parks or Wildernesses. They do, however, provide broad direction on what should be protected in Parks and Wildernesses (the earth and its community of life) and to what degree (preserve natural conditions or conserve resources unimpaired). Accordingly, FLMs have developed the following policies related to air quality and Class I areas:

1. Class I areas are not merely a commodity for human use and consumption. Park and Wilderness ecosystems have intrinsic values other than user/public concerns.
2. A principal objective of FLM management is to offer a natural user experience, rather than strictly an enjoyable one. The amount of enjoyment is purely a personal matter for the individual user to decide.
3. All Class I components are equally important; none is of lesser value than another.
4. A Class I component is important even if users of the area are unaware of its existence.
5. All life forms are equally important. For example, microorganisms are as essential as elk, wild flowers, or grizzly bears.
6. The goal of Class I management is to protect not only resources with immediate aesthetic appeal (i.e., sparkling clean streams) but also unseen ecological processes (such as natural biodiversity and gene pools).
7. The most sensitive Class I components are to be emphasized more than those of "average" or "normal" sensitivity. Sensitivity is generally determined by inertia (resistance to change), elasticity (how far the component can be stretched from its natural condition without being permanently modified), and resiliency (the number of times it can revert to its natural condition after experiencing human-caused change).
8. Each Class I component is important in itself; as well as in terms of how it interacts with other components of the ecosystem. That is, the individual parts of the Class I ecosystem are as significant as the sum of the parts.
9. The physical components of the ecosystem (for instance, lake chemistry) are as essential as its biological constituents (i.e., salamanders). That is, the earth is as essential as the community of life.
10. Class I components are to be protected from "human-caused change" rather than from "damage." Terms such as "damage" and "harm" are prejudicial, whereas "human-caused change" is value-neutral. (For example, deposits of nitrogen in a lake from nitrogen oxide, a common air pollutant, might result in more plant growth and larger fish. This would, however, be an unnatural - and therefore unacceptable - change in the aquatic ecosystem).
11. The goal of Class I management is to protect natural conditions, rather than the conditions when first monitored. That is, if initial monitoring in a Class I area identifies human-caused changes, appropriate actions should be taken to remedy them, in order to move towards a more natural condition.
12. The designation of a Park or Wilderness as Class I or II does not dictate the management goals for it; these are identified in the enabling legislation. The designation only determines which options are available to meet the goals. Class I Parks or Wildernesses, for instance, can be protected through AQRV analysis, whereas the protection of Class II Parks and Wildernesses can be achieved using BACT requirements.
13. The FLMs will do their best to manage and protect resources at every area that they administer.
14. Although monitoring is critical to many air resource management decisions, it must not interfere needlessly with Park or Wilderness. Where possible, the most intrusive monitoring and instrumentation should be conducted adjacent to the Class I area - if such areas adequately represent the area of concern.

Appendix D: Best Available Control Technology (BACT) Analysis

Given the need to minimize emissions and their resulting air quality impacts, the FLMs recommend that the applicant conduct the BACT analysis using EPA's top-down approach. In brief, a top-down process ranks all available control technologies in descending order of control effectiveness. All of the available control systems for the source, including the most stringent, must be considered. The applicant first examines the most effective, or top, alternative. That alternative is established as the BACT unless the applicant demonstrates, and the permitting authority agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not achievable in that case. FLMs utilize EPA's BACT/RACT/LAER Clearinghouse, and other information, for assessing control technologies proposed by permit applicants.

If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on. Permit applicants should refer to chapter B of the EPA Draft New Source Review Workshop Manual for a detailed discussion of the top-down policy (EPA 1990).

The FLM reviews the applicant's BACT analysis to determine if the best available pollution control technology is being proposed, thereby minimizing the proposed emission increases and their corresponding impact on the FLM area in question. The FLM does this by comparing the proposed controls to recent BACT determinations for similar facilities. If the FLM disagrees with the applicant's BACT analysis, technical comments are submitted to the permitting authority that has the ultimate responsibility to make the BACT determination and issue the permit.

The environmental impacts analysis of the BACT review is not to be confused with the air quality-related analysis. The environmental impacts analysis of the BACT review should concentrate on impacts other than ambient air quality impacts of the regulated pollutant in question, such as solid or hazardous waste generation, discharges of polluted water from a control device, or emissions of unregulated pollutants. Thus, the fact that a given control alternative would result in only a slight improvement in ambient concentrations of the pollutant in question when compared with a less stringent control alternative, should not be viewed as a basis for rejecting the more stringent control alternative.

Regarding the economic impact analysis, given the special protection Class I areas are afforded under the Clean Air Act, FLMs believe that the need to minimize potential impacts on a Class I area should be a major consideration in the BACT determination for a project proposed near such an area. Therefore, if a source proposes to locate near a Class I area, additional costs to minimize impacts on sensitive Class I resources may be warranted, even though such costs may be considered economically unjustified under other circumstances.

Appendix E: Maps of Federal Class I Areas



Figure 8. National Park Service Class I Areas
Map produced by the National Park Service Air Resources Division March 2010.



Figure 9. Fish and Wildlife Service Class I Areas
Map produced by the National Park Service Air Resources Division March 2010.



Figure 10. Forest Service Class I Wilderness Areas
Map produced by the National Park Service Air Resources Division March 2010.

Appendix F: FLAG 2000 Participants

The individuals listed in the attached table participated in the development of the *FLAG Phase I Report* (December 2000). The contact information was not updated as part of this FLAG 2010 revision. The abbreviations for the FLAG subgroup or committee on which participants served are shown below.

LC = Leadership Committee

CC = Coordinating Committee

P = Policy Subgroup

V = Visibility Subgroup

O = Ozone Subgroup

D = Deposition Subgroup

T = Terminology (Glossary) Subgroup

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Appendix G: Bibliography (Revised)

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The Department of the Interior protects and manages the nation's natural resources and cultural heritage; provides scientific and other information about those resources; and honors its special responsibilities to American Indians, Alaska Natives, and affiliated Island Communities.

NPS 999/105412, October 2010

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EXHIBIT 12

to Sierra Club Comments

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

OFFICE OF
AIR QUALITY PLANNING
AND STANDARDS

MAY 20 2014

MEMORANDUM

SUBJECT: Guidance for $PM_{2.5}$ Permit Modeling

FROM: Stephen D. Page M. Stephen Page for
Director

TO: Regional Air Division Directors, Regions 1-10

This memorandum and attachment, titled "Guidance for $PM_{2.5}$ Permit Modeling," provides guidance on demonstrating compliance with the fine particulate matter ($PM_{2.5}$) National Ambient Air Quality Standards (NAAQS) and Prevention of Significant Deterioration (PSD) increments, especially with regard to considerations of the secondarily formed component of $PM_{2.5}$. This document reflects the EPA's recommendations for how a major stationary source seeking a PSD permit may demonstrate that it will not cause or contribute to a violation of the NAAQS and PSD increments for $PM_{2.5}$, as required under section 165(a)(3) of the Clean Air Act (CAA) and 40 CFR Sections 51.166(k) and 52.21(k).

A draft version of this guidance document was provided to the public on March 4, 2013, for a 90-day comment period. The document was revised in response to public comments and additional information provided through on-going interactions with various stakeholders.

Noteworthy changes made to the draft version include:

- Clarifications throughout with respect to procedures for adequately addressing primary and secondarily formed $PM_{2.5}$.
- Inclusion of an example hybrid (qualitative/quantitative) secondary $PM_{2.5}$ impact assessment.
- Revision of a second tier cumulative $PM_{2.5}$ NAAQS compliance approach.
- Revision of Section V and other sections relative to PSD increment for $PM_{2.5}$.

Please distribute the attached guidance document to state, local, and tribal governments, as appropriate. If you have any questions regarding this document, please contact Tyler Fox, Air Quality Modeling Group Leader, Air Quality Assessment Division/OAQPS, at (919) 541-5562, fox.tyler@epa.gov.

Attachment

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Guidance for $PM_{2.5}$ Permit Modeling

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EPA-454/B-14-001
May 2014

Guidance for $PM_{2.5}$ Permit Modeling

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Air Quality Assessment Division
Research Triangle Park, North Carolina

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Appendix A: Draft Conceptual Description of $PM_{2.5}$ Concentrations in the U.S. A-1

Appendix B: General Guidance on Use of Dispersion Models for Estimating Primary $PM_{2.5}$ Concentrations B-1

Appendix C: Example of a Qualitative Assessment of the Potential for Secondary $PM_{2.5}$ Formation C-1

Appendix D: Example of a Hybrid Qualitative/Quantitative Assessment of the Potential for Secondary $PM_{2.5}$ Formation D-1

Appendix E: Example of the background monitoring data calculations for a Second Tier 24-hour modeling analysis E-1

Disclaimer

This document recommends procedures for permit applicants and permitting authorities to use to show that they have satisfied the criteria for obtaining or issuing a permit under applicable regulations. This document is not a rule or regulation, and the guidance it contains may not apply to a particular situation based upon the individual facts and circumstances. This guidance does not change or substitute for any law, regulation, or any other legally binding requirement and is not legally enforceable. The use of non-mandatory language such as "guidance," "recommend," "may," "should," and "can," is intended to describe EPA policies and recommendations. Mandatory terminology such as "must" and "required" are intended to describe controlling requirements under the terms of the Clean Air Act and EPA regulations, but this document does not establish legally binding requirements in and of itself. This document does not create any rights or obligations enforceable by any party or impose binding, enforceable requirements on any permit applicant for a PSD permit or PSD permitting authority.

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Executive Summary

The U.S. Environmental Protection Agency (EPA) is providing this "Guidance for $PM_{2.5}$ Permit Modeling" to fulfill a need for additional guidance on demonstrating compliance with the fine particulate matter ($PM_{2.5}$) National Ambient Air Quality Standards (NAAQS) and the Prevention of Significant Deterioration (PSD) increments, especially with regard to considerations of the secondarily formed components of $PM_{2.5}$. This guidance incorporates the modeling procedures and recommendations from the EPA's March 23, 2010, guidance memorandum, "Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS," and further clarifies procedures for adequately addressing primary and secondarily formed $PM_{2.5}$ in a NAAQS and PSD increments compliance demonstration. This guidance is consistent with the EPA's *Guideline on Air Quality Models,* also published as Appendix W of Title 40 of the Code of Federal Regulations (CFR) Part 51. The release of this "Guidance for $PM_{2.5}$ Permit Modeling" is also consistent with the commitments contained in the EPA's January 4, 2012, grant of a July 28, 2010, petition filed by the Sierra Club.

Because of the complex chemistry of secondary formation of $PM_{2.5}$, the EPA's judgment in the past has been that it was not technically sound to assign with particularity specific models that must be used to assess the impacts of a single source on $PM_{2.5}$ concentrations. Instead, the EPA has determined it was appropriate to satisfy the requirements of Section 165(e)(3)(D) of the Clean Air Act (CAA) by recommending that the "[c]hoice of methods used to assess the [$PM_{2.5}$] impact of an individual source depends on the nature of the source and its emissions," as stated in Section 5.2.2.1.c. of Appendix W. As such, the appropriate methods for assessing $PM_{2.5}$ impacts are determined as part of the normal consultation process with the appropriate permitting authority. A modeling protocol should be developed by the permit applicant and approved by the

appropriate permitting authority to ensure that the analysis conducted will conform to the recommendations, requirements, and principles of Section 10.2.1 of Appendix W. This guidance is intended to inform that process through recommendations regarding appropriate methods to assess secondary $PM_{2.5}$ impacts from the precursor emissions from the new or modifying source by providing the permit applicant and the appropriate permitting authority with both focus and flexibility. As experience is gained with these NAAQS and increments compliance demonstrations (and as the EPA moves forward to consider single source modeling techniques pursuant to its grant of the petition from the Sierra Club), this guidance will likely evolve such that the EPA will be able to provide further specificity on assessing the impacts of a single source on $PM_{2.5}$ concentrations.

This guidance document is broken down into five primary sections:

- I. Background – The first section provides the relevant regulatory actions and historical context to this guidance starting with the promulgation of the initial $PM_{2.5}$ NAAQS in 1997; chronicling the PM_{10} Surrogate Policy that for a period of time was relied upon for demonstrating compliance with the $PM_{2.5}$ NAAQS; and arriving at the present where there is a need for an assessment of both the primary and secondary $PM_{2.5}$ impacts, as appropriate, of a new or modifying source for demonstrating compliance with $PM_{2.5}$ NAAQS and increments.
- II. Guidance Overview – The second section provides a general overview of the steps that a permit applicant would routinely take under the PSD program for demonstrating compliance with the $PM_{2.5}$ NAAQS and increments. The concepts of significant emissions rates (SERs) and significant impact levels (SILs) are introduced and then presented in the context of a source impact analysis and a cumulative impact

analysis. The ramifications of the January 22, 2013, decision from U.S. Court of Appeals for the District of Columbia Circuit on the use of SILs in a source impact analysis or otherwise are included for reference and consideration throughout the remaining sections. Four assessment cases (Table ES-1) are then introduced with respect to assessing the primary and secondary $PM_{2.5}$ impacts through either the source impact analysis or the cumulative impact analysis.

- III. Source Impact Analysis for the $PM_{2.5}$ NAAQS – The third section provides a detailed discussion of a screening assessment of primary and secondary $PM_{2.5}$ impacts from a new or modifying source using a SIL. The specifics of the four assessment cases (Table ES-1) are presented along with appropriate approaches for assessing the primary and secondary impacts of $PM_{2.5}$. For assessing the primary $PM_{2.5}$ impacts from the direct $PM_{2.5}$ emissions from the new or modifying source, the typical use of an appropriate preferred dispersion model for near-field $PM_{2.5}$ modeling listed in Appendix W, currently AERMOD for most applications, or an approved alternative model is recommended. For assessing the secondary $PM_{2.5}$ impacts from the precursor emissions from the new or modifying source, three different approaches are described. These approaches are 1) a qualitative assessment, 2) a hybrid qualitative/quantitative assessment utilizing existing technical work, and 3) a full quantitative photochemical grid modeling exercise.
- IV. Cumulative Impact Analysis for the $PM_{2.5}$ NAAQS – The fourth section provides a detailed discussion of the assessment of primary and secondary $PM_{2.5}$ impacts from a new or modifying source with the inclusion of the primary and secondary $PM_{2.5}$ impacts of nearby sources and of monitored background. There are specific

discussions of the modeling inventory and the monitored background. Section IV concludes with information on determining significant contributions to modeled violations.

- V. PSD Increments for $PM_{2.5}$ – The fifth section provides a detailed discussion of the assessment of primary and secondary $PM_{2.5}$ impacts of a new or modifying source with respect to the increments.

Table ES-1. EPA Recommended Approaches for Assessing Primary and Secondary $PM_{2.5}$ Impacts by Assessment Case

Assessment Case	Description of Assessment Case	Primary Impacts Approach	Secondary Impacts Approach
Case 1: No Air Quality Analysis	Direct PM2.5 emissions < 10 tpy SER NOx and SO2 emissions < 40 tpy SER	N/A	N/A
Case 2: Primary Air Quality Impacts Only	Direct PM2.5 emissions ≥ 10 tpy SER NOx and SO2 emissions < 40 tpy SER	**Appendix W preferred or approved alternative dispersion model**	N/A
Case 3: Primary and Secondary Air Quality Impacts	Direct PM2.5 emissions ≥ 10 tpy SER NOx and/or SO2 emissions ≥ 40 tpy SER	**Appendix W preferred or approved alternative dispersion model**	• **Qualitative** • **Hybrid qualitative / quantitative** • **Full quantitative photochemical grid modeling**
Case 4: Secondary Air Quality Impacts Only	Direct PM2.5 emissions < 10 tpy SER NOx and/or SO2 emissions ≥ 40 tpy SER	N/A	• **Qualitative** • **Hybrid qualitative / quantitative** • **Full quantitative photochemical grid modeling**

In summary, this "Guidance for $PM_{2.5}$ Permit Modeling" recommends technical approaches for conducting $PM_{2.5}$ NAAQS and PSD increments compliance demonstrations which include adequate accounting for contributions from primary $PM_{2.5}$ concentrations from a proposed new or modifying source's direct $PM_{2.5}$ emissions and from secondarily formed $PM_{2.5}$ concentrations resulting from the source's $PM_{2.5}$ precursor emissions. This guidance does not create any rights or obligations enforceable by any party or impose binding, enforceable requirements on any permit applicant for a PSD permit or PSD permitting authority. Since each

permitting action will be considered on a case-by-case basis, this document does not limit or restrict any particular justifiable approach permit applicants and permitting authorities may take to conduct the required compliance demonstrations. Each individual decision to issue a PSD permit must be supported by a record sufficient to demonstrate that the proposed construction and operation of a stationary source will not cause or contribute to a violation of the applicable $PM_{2.5}$ NAAQS and PSD increments. While this document illustrates a particular approach that the EPA considers appropriate and acceptable as a general matter, permit applicants and permitting authorities should examine all relevant information regarding air quality in the area that may be affected by a proposed new or modified source and evaluate whether alternative or additional analysis may be necessary in a given case to demonstrate that the criteria for obtaining a permit are satisfied. This document does not represent a conclusion or judgment by EPA that the technical approaches recommended in this document will be sufficient to make a successful compliance demonstration in every permit application or circumstance.

Permitting authorities retain the discretion to address particular issues discussed in this document in a different manner than the EPA recommends so long as the approach is adequately justified, supported by the permitting record and technical literature, and consistent with the applicable requirements in the CAA and implementing regulations, including the terms of an approved State Implementation Plan (SIP).

Furthermore, this guidance does not represent final agency action with respect to applicable legal requirements or the approvability of any particular permit application. To improve the quality of this guidance, the EPA has solicited public comment and considered the comments submitted. The EPA has revised the draft guidance in response to many points raised in public comment, but this document does not reflect a final determination by the EPA as to any

issue raised in public comments. Concerns expressed in public comments about the permissibility or sufficiency of the approach recommended in this guidance for making the required demonstration in particular circumstances may be raised in the context of each individual permit application and should be considered by the permitting authority in light of the record in each instance before making a final determination to issue or deny a PSD permit.

Acknowledgements

We would like to acknowledge contributions from members of the National Association of Clean Air Agencies (NACAA) $PM_{2.5}$ Modeling Implementation Workgroup (NACAA Workgroup) in providing a detailed set of recommendations (NACAA, 2011) to the EPA with regards to $PM_{2.5}$ permit compliance demonstration modeling. This NACAA Workgroup was comprised of state and local air permitting agency dispersion modelers, permit engineers, and technical staff from throughout the country. In particular, we recognize Jim Hodina (Linn County Public Health), Bob Hodanbosi (Ohio EPA, Division of Air Quality), and Clint Bowman (Washington Department of Ecology) for their roles as Chairpersons for the Emissions Inventories, Secondary Formation from Project Source, and Representative Background Concentrations Sub-workgroups, respectively.

We would also like to acknowledge the contributions of the staff of the EPA Office of Transportation and Air Quality (OTAQ) for their input and assistance in the development of this document. The EPA's "Transportation Conformity Guidance for Quantitative Hot-spot Analyses in $PM_{2.5}$ and PM_{10} Nonattainment and Maintenance Areas" (U.S. EPA, 2013a) guidance document served as a foundation for many aspects of the modeling guidance contained within this document.

Finally, there were numerous comments received with respect to issues and concerns of demonstrating compliance with the NAAQS and increments for $PM_{2.5}$ during the formal public comment period for the 10^{th} Conference on Air Quality Modeling and comprehensive comments received specific to the overall guidance and recommendations presented here through the comment period for the "Draft Guidance on $PM_{2.5}$ Permit Modeling" (U.S. EPA 2013b). This invaluable feedback along with additional information gleaned through ongoing interactions with

various stakeholders have been particularly useful in the consideration of a range of acceptable options for $PM_{2.5}$ NAAQS and PSD increments compliance demonstrations and aided the EPA in the completion of this guidance document

I. Background

Under Section 165(a)(3) of the CAA, a PSD permit applicant must demonstrate that emissions from the proposed construction and operation of a facility "will not cause, or contribute to, air pollution in excess of any (A) maximum allowable increase or maximum allowable concentration for any pollutant… , [or] (B) national ambient air quality standard…" This requirement is implemented in the PSD regulations at 40 CFR 52.21(k)(1) (and at 40 CFR 51.166(k)(1) with slightly different wording) as follows:

> (k) *Source impact analysis*—(1) *Required demonstration*. The owner or operator of the proposed source or modification shall demonstrate that allowable emission increases from the proposed source or modification, in conjunction with all other applicable emissions increases or reductions (including secondary emissions), would not cause or contribute to air pollution in violation of:
>
> (i) Any national ambient air quality standard in any air quality control region; or
>
> (ii) Any applicable maximum allowable increase over the baseline concentration in any area.

On July 18, 1997, the EPA revised the NAAQS for particulate matter (PM) to add new annual and 24-hour standards for fine particles using particulate matter less than 2.5 micrometers or $PM_{2.5}$ as the indicator.[1] The EPA revised the 24-hour NAAQS for $PM_{2.5}$ on September 21, 2006, by lowering the level of the standard from 65 $\mu g/m^3$ to 35 $\mu g/m^3$.[2] In the September 21, 2006, action, the EPA also retained the previous 1997 annual standard for $PM_{2.5}$ and the 24-hour standard for PM_{10}, and revoked the previous annual standard for PM_{10}. Subsequently, the

[1] See 62 Fed. Reg. 58652.

[2] See 71 Fed. Reg. 61144.

Agency revised the $PM_{2.5}$ standard again on December 14, 2012, by lowering the level of the annual $PM_{2.5}$ NAAQS from 15 $\mu g/m^3$ to 12 $\mu g/m^3$ and retaining the 24-hour standards for $PM_{2.5}$ and PM_{10}.[3] The annual $PM_{2.5}$ standard is met when the 3-year average of annual arithmetic mean concentrations is less than or equal to 12.0 $\mu g/m^3$. The 24-hour $PM_{2.5}$ standard is met when the 3-year average of the annual 98^{th} percentile 24-hour concentrations is less than or equal to 35 $\mu g/m^3$.

On October 20, 2010, EPA established maximum allowable increases for $PM_{2.5}$.[4] These values are also frequently described as the PSD increments. For Class I areas, the increments for $PM_{2.5}$ are 1 $\mu g/m^3$ for the annual averaging time and 2 $\mu g/m^3$ for the 24-hour averaging time. In Class II areas, the increments are 4 $\mu g/m^3$ for the annual period and 9 $\mu g/m^3$ for the 24-hour period.

To address the compliance demonstration for the $PM_{2.5}$ NAAQS, on October 23, 1997, citing significant technical difficulties with respect to $PM_{2.5}$ monitoring, emissions estimation, and modeling, the EPA established a policy known as the PM_{10} Surrogate Policy (U.S. EPA, 1997). This policy allowed permit applicants to use compliance with the applicable PM_{10} requirements as a surrogate approach for meeting $PM_{2.5}$ New Source Review (NSR) requirements until certain technical difficulties were resolved. On May 16, 2008, the EPA promulgated final rules governing the implementation of the NSR program for $PM_{2.5}$, which facilitated phasing out the application of the PM_{10} Surrogate Policy to permits involving $PM_{2.5}$.[5] With regard to nonattainment NSR permits, the rule provided that as of July 15, 2008 (the rule's effective date), permit applicants and permitting authorities would no longer be able to use the

[3] See 78 Fed. Reg. 3086.

[4] See 75 Fed. Reg. 64864.

[5] See 73 Fed. Reg. 28321.

PM_{10} Surrogate Policy to satisfy the NSR requirements for $PM_{2.5}$. With regard to PSD permits, the rule provided that PSD permits issued under the federal PSD program at 40 CFR 52.21 would no longer be allowed to rely on the PM_{10} Surrogate Policy as of the effective date of the rule. The exception to this outcome was that the rule also provided a "grandfathering provision" allowing permit applicants for federal PSD permits covered by 40 CFR 52.21, with complete permit applications submitted as of July 15, 2008, to continue relying on the PM_{10} Surrogate Policy. The 2008 rule also provided that states with approved PSD programs for $PM_{2.5}$ could continue to use the PM_{10} Surrogate Policy until May 2011 (when SIP revisions containing provisions to meet the new requirements in the 2008 rule were due), or until the EPA approved the revised SIP for $PM_{2.5}$, whichever occurred first.

On June 1, 2009, in response to a petition challenging the continued use of the PM_{10} Surrogate Policy for issuing PSD permits, the EPA issued a 3-month administrative stay of the grandfathering provision for $PM_{2.5}$ affecting federal PSD permits to give the EPA time to propose repealing the challenged grandfathering provision.[6] On September 16, 2009, the original 3-month stay was extended to June 22, 2010, to allow additional time for the EPA to propose repealing the grandfathering provision from the $PM_{2.5}$ NSR implementation rule for federal PSD permits issued under 40 CFR 52.21.[7] On February 11, 2010, the EPA published its proposal to repeal the grandfathering provision.[8] These actions cite the fact that the technical difficulties that necessitated the PM_{10} Surrogate Policy had been largely, although not entirely, resolved. As part of the proposed rulemaking to repeal the grandfathering provision contained in the federal PSD program, the EPA also proposed to require an early end to the use of the PM_{10} Surrogate Policy

[6] See 74 Fed. Reg. 26098.

[7] See 74 Fed. Reg. 48153.

[8] See 75 Fed. Reg. 6827.

for state PSD programs that the EPA had already approved as part of the SIP required by 40 CFR 51.166.

On May 18, 2011, the EPA published a final rule, titled "Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$); Final Rule to Repeal Grandfather Provision" (76 Fed. Reg. 28646), that repealed the grandfathering provision. In that final action, the EPA ended the use of the PM_{10} Surrogate Policy for PSD permits under the federal PSD program for sources that were covered by the grandfathering provision (that is, those sources for which a complete permit application was submitted before July 15, 2008) and that were not yet issued a permit by the effective date of the final rule. [9] The final rule also reaffirmed that as of May 2011, states with SIP-approved PSD programs for $PM_{2.5}$ could no longer use the PM_{10} Surrogate Policy. After the final rule became effective, in order for any PSD permits to be issued through the federal PSD program or a state SIP, such permit applications were to be reviewed directly against the $PM_{2.5}$ requirements. The demonstration must show, at a minimum, that the source's emissions are controlled to a level that satisfies Best Available Control Technology (BACT) requirements for $PM_{2.5}$ and that the emissions (filterable and condensable[10]) would not cause or contribute to a violation of any NAAQS for $PM_{2.5}$.

On March 23, 2010, the EPA issued a guidance memorandum titled "Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS" (U.S. EPA, 2010b) to assist sources and permitting authorities in carrying out the required air quality analysis. The guidance memorandum recommended certain interim procedures to address the fact that compliance with the $PM_{2.5}$ NAAQS is based on a statistical form, and that there are technical complications

[9] Sources that applied for a PSD permit under the federal PSD program on or after July 15, 2008, were already excluded from using the 1997 PM10 Surrogate Policy as a means of satisfying the PSD requirements for PM2.5. See 73 Fed. Reg. 28321.

[10] See 40 CFR 51.165(a)(l)(xxxvii)(D), 51.166 (b)(49)(i)(a), and 52.21(b)(50) (i)(a).

associated with the ability of existing models to estimate the impacts of secondarily formed $PM_{2.5}$ in the atmosphere resulting from emissions of $PM_{2.5}$ precursors. For the latter issue, the EPA recommended that special attention be given to the assessment of monitored background air quality data since such data account for the contribution of both primary and secondarily formed $PM_{2.5}$ in the atmosphere associated with both nearby and regional sources.

On January 7, 2011, the NACAA Workgroup delivered a final report (NACAA, 2011), including a set of specific recommendations, to the EPA. The NACAA Workgroup was formed in early 2010 with the objective of providing technical recommendations to the Agency to aid in further development of $PM_{2.5}$ permit modeling guidance. The NACAA Workgroup's final report addressed three specific issues regarding $PM_{2.5}$ modeling implementation: 1) Emissions Inventories; 2) Secondary Formation from Project Source; and 3) Representative Background Concentrations.

The need for additional clarification on addressing both the primary and secondarily formed $PM_{2.5}$ in NAAQS compliance demonstrations was heightened following an administrative action on January 4, 2012, in which the EPA granted a petition submitted on behalf of the Sierra Club on July 28, 2010 (U.S. EPA, 2012a). The Sierra Club petition requested that the EPA initiate rulemaking to establish air quality models for ozone and $PM_{2.5}$ for use by all major sources applying for a PSD permit. In the petition grant, the EPA committed to engage in rulemaking to evaluate updates to the *Guideline on Air Quality Models* as published as Appendix W of 40 CFR Part 51 and, as appropriate, incorporate new analytical techniques or models for ozone and secondarily formed $PM_{2.5}$. As a part of this commitment and in compliance with Section 320 of the CAA, the EPA conducted the 10^{th} Conference on Air Quality Modeling

(10th Modeling Conference) in March 2012. [11] At the 10th Modeling Conference, there were invited presentations of ongoing research of single source plume chemistry and photochemical grid modeling techniques, an overview presentation on the development of the "Draft Guidance for $PM_{2.5}$ Permit Modeling", and several public forums and subsequently written comments given pertaining to $PM_{2.5}$ NAAQS modeling.

Based on the EPA's March 23, 2010, guidance memorandum, the NACAA Workgroup final report recommendations, input from a mixture of stakeholders through numerous forums, and permit applicant-submitted $PM_{2.5}$ compliance demonstrations up to that point, the EPA prepared the "Draft Guidance on $PM_{2.5}$ Permit Modeling" and released it for public comment on March 4, 2013. During the course of the public comment period following the release of the draft guidance, the EPA received numerous comprehensive comments that provided invaluable feedback on the document and on the newly recommended approaches for $PM_{2.5}$ NAAQS and PSD increments compliance demonstrations. This feedback along with additional information gleaned through ongoing interactions with various stakeholders was particularly useful in the consideration of a range of acceptable options for $PM_{2.5}$ NAAQS and PSD increments compliance demonstrations and aided the EPA in the completion of this guidance document.

This "Guidance for $PM_{2.5}$ Permit Modeling" recommends appropriate technical approaches for conducting a $PM_{2.5}$ NAAQS and PSD increments compliance demonstration which includes adequate accounting for contributions from primary $PM_{2.5}$ concentration from a proposed new or modifying source's direct $PM_{2.5}$ emissions and from secondarily formed $PM_{2.5}$ concentrations resulting from the source's $PM_{2.5}$ precursor emissions. This guidance is consistent with the EPA's *Guideline on Air Quality Models*. The release of this "Guidance for $PM_{2.5}$ Permit

[11] Additional information regarding and presentations from the 10th Modeling Conference can be found on the SCRAM website at: http://www.epa.gov/ttn/scram/10thmodconf.htm.

Modeling" is also consistent with the commitments contained in the EPA's January 4, 2012, grant of the July 28, 2010, petition filed by the Sierra Club.

Since each permitting action will be considered on a case-by-case basis, this guidance does not limit or restrict any particular justifiable approach permit applicants and permitting authorities may take to conduct the required compliance demonstrations. Prospective permit applicants should recognize the importance of the consultation process with the appropriate permitting authority. This process will help identify the most appropriate analytical techniques to be used for conducting a $PM_{2.5}$ NAAQS and PSD increments compliance demonstration, including addressing the impacts of individual sources on secondary $PM_{2.5}$ formation, pursuant to Section 5.2.2.1.c of Appendix W.

In addition to this guidance, other recently issued EPA guidance of relevance for consideration in permit modeling for $PM_{2.5}$ includes:

- "Model Clearinghouse Review of Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS," February 26, 2010 (U.S. EPA, 2010a);
- "Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS," March 23, 2010 (U.S. EPA, 2010b);
- "Transportation Conformity Guidance for Quantitative Hot-spot Analyses in $PM_{2.5}$ and PM_{10} Nonattainment and Maintenance Areas," November 2013 (U.S.EPA, 2013); and
- "Interim Guidance on the Treatment of Condensable Particulate Matter Test Results in the PSD and NSR Permitting Programs," April 8, 2014 (U.S. EPA, 2014a).

The guidance listed above, in addition to other relevant support documents, can be found on the SCRAM website at http://www.epa.gov/ttn/scram/.

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II. Guidance Overview

This modeling guidance provides recommendations on how to conduct a $PM_{2.5}$ NAAQS and PSD increments compliance demonstration under the PSD program. It is based on and is consistent with Appendix W. Appendix W is the primary source of information on the regulatory application of air quality models for SIP revisions for existing sources and for NSR and PSD programs for permitting new and modifying sources.

The complexity of secondary $PM_{2.5}$ formation has historically presented significant challenges for the identification and establishment of particular models for assessing the $PM_{2.5}$ impacts of individual stationary sources (NARSTO, 2004; Seinfeld and Pandis, 1998; Cohan and Napelenok, 2011). Because of these considerations, the EPA's judgment in the past has been that it was not technically sound to assign with particularity specific models that must be used to assess the impacts of a single source on $PM_{2.5}$ concentrations.[12] Instead, the EPA has chosen to satisfy the requirements of the CAA, Section 165(e)(3)(D) through a process of determining particular models or other analytical techniques that should be used on a case-by-case basis because the "[c]hoice of methods used to assess the [$PM_{2.5}$] impact of an individual source depends on the nature of the source and its emissions," as stated in Section 5.2.2.1c. of Appendix W. As such, the appropriate methods for assessing $PM_{2.5}$ impacts are determined as part of the normal consultation process with the appropriate permitting authority. A modeling protocol should be developed by the permit applicant and approved by the appropriate permitting authority to ensure that the analysis conducted will conform to the recommendations, requirements, and principles of Section 10.2.1 of Appendix W.

[12] We note that this technical judgment has no effect on the obligation of sources subject to PSD to conduct a source impact analysis and demonstrate that a proposed source or modification will not cause or contribute to a violation of any NAAQS or applicable increment. See 40 CFR 51.166(k); 52.21(k). That is, the inclusion of a process rather than a specific preferred model in Appendix W does not relieve the source of the requirement to make this demonstration, which necessarily involves an analysis.

Due to the potentially important contribution from secondary formation of $PM_{2.5}$ and the more prominent role of ambient monitoring data in the cumulative analysis to represent background $PM_{2.5}$ concentrations including secondary formation from precursors from nearby sources, certain aspects of standard modeling practices used for PM_{10} and other criteria pollutants may not be appropriate for $PM_{2.5}$. For example, the contribution from secondary formation of $PM_{2.5}$ is not explicitly accounted for by the current preferred dispersion model (i.e., AERMOD), which is used to simulate dispersion of direct $PM_{2.5}$ emissions. Given these issues, PSD modeling of secondarily formed $PM_{2.5}$ should currently be viewed as screening-level analyses under Appendix W, analogous to Section 5.2.4 of Appendix W regarding dispersion modeling for nitrogen dioxide (NO_2) impacts due to the importance of chemistry in the conversion of nitric oxide (NO) emissions to ambient NO_2 and lack of a specified "refined" model.[13] The recommendations presented in this guidance for demonstrating compliance with the $PM_{2.5}$ NAAQS through dispersion modeling and other techniques have been developed with the factors listed above in mind.

As with any modeling analysis conducted using approved models identified in Appendix W, alternative models and methods may be considered on a case-by-case basis, subject to approval by the EPA Regional Office in accordance with the recommendations in Section 3.2. Additionally, Section 10.2.2 of Appendix W could potentially be given consideration in select situations. The provisions of Section 10.2.2 acknowledge that there are circumstances where there is no applicable model for a particular NAAQS compliance demonstration and that data

[13] Section 5.2.4 of Appendix W puts forth a 3-tiered screening approach for NO_2 NAAQS compliance demonstrations to obtain estimates of NO_2 for PSD and SIP planning purposes. The level of conservativeness in the tiered approaches decreases as fewer assumptions are made and a more detailed analysis is applied with the 3rd tier approach being the use of detailed screening techniques based on dispersion modeling.

from an array of ambient monitors surrounding the facility to be permitted could be used in lieu of modeling if appropriately justified.

Given the complexity of the technical issues that arise in the context of demonstrating compliance with the $PM_{2.5}$ NAAQS, we strongly encourage following the recommendations in Section 10.2.1 of Appendix W that "[e]very effort should be made by the Regional Office to meet with all parties involved in either a SIP revision or a PSD permit application prior to the start of any work on such a project. During this meeting, a protocol should be established between the preparing and reviewing parties to define the procedures to be followed, the data to be collected, the model to be used, and the analysis of the source and concentration data." Furthermore, we recommend that the consultative process involve regular communication between the appropriate permitting authority and the permit applicant at key milestones to ensure timely resolution of issues that may arise.

As necessary, the EPA Regional Office may seek clarification from the EPA's Office of Air Quality Planning and Standards (OAQPS) on technical issues and areas of concern in a modeling protocol or NAAQS compliance demonstration. Through these interactions and subsequent resolutions of the specific issues, clarifications of preferred modeling procedures can ultimately become official EPA guidance. This can happen in several ways: 1) the preferred procedures are published as regulations or guidelines; 2) the preferred procedures are formally transmitted as guidance to the Air Division Directors in the EPA Regional Offices; 3) the preferred procedures are formally transmitted as guidance to the EPA Regional Office modeling contacts as a result of a regional consensus on technical issues; or 4) the preferred procedures are relied upon in decisions by the EPA's Model Clearinghouse that effectively establish national precedent that the approach is technically sound. The Model Clearinghouse is the EPA focal

point for the review of the technical adequacy of pollutant modeling to satisfy regulatory criteria and other NAAQS compliance demonstration techniques. Model Clearinghouse memoranda involving interpretation of modeling guidance for specific applications, as well as clarification memoranda addressing needs to clarify guidance more generally, are available at the Support Center for Regulatory Atmospheric Modeling (SCRAM) website at: http://www.epa.gov/ttn/scram.

The guidance that follows is appropriate for those new or modifying sources locating or located in an area classified as attainment or unclassifiable for $PM_{2.5}$. This document is intended to provide recommendations on how to conduct $PM_{2.5}$ NAAQS and PSD increments compliance demonstrations under the PSD program following the progressive steps shown in Figure II-1 (NAAQS) and Figure II-2 (Increments). The EPA has historically allowed the use of screening tools to help facilitate the implementation of the PSD program and streamline the permitting process in circumstances where proposed construction is projected to have an insignificant (or *de minimis*) impact on air quality. These screening tools have included SERs, SILs, and significant monitoring concentrations (SMCs). The use of these screening tools at each progressive step on the left side (attainment or unclassifiable areas) of Figure II-1 and Figure II-2 are described in more detail in Sections II.1, II.2, and II.3.

Figure II-1. Overview of $PM_{2.5}$ NAAQS Compliance Demonstration for New or Modifying Sources under NSR/PSD Programs

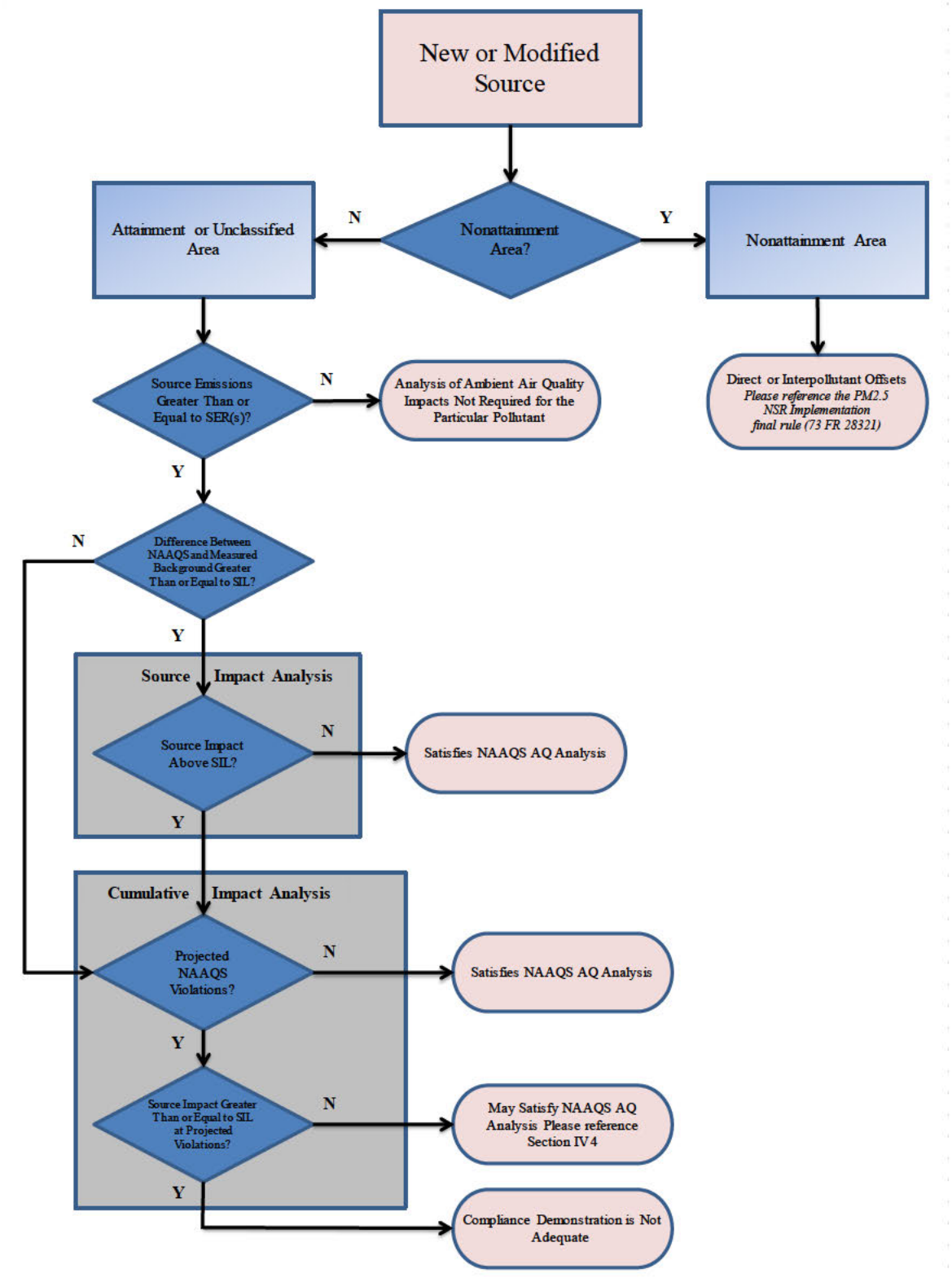
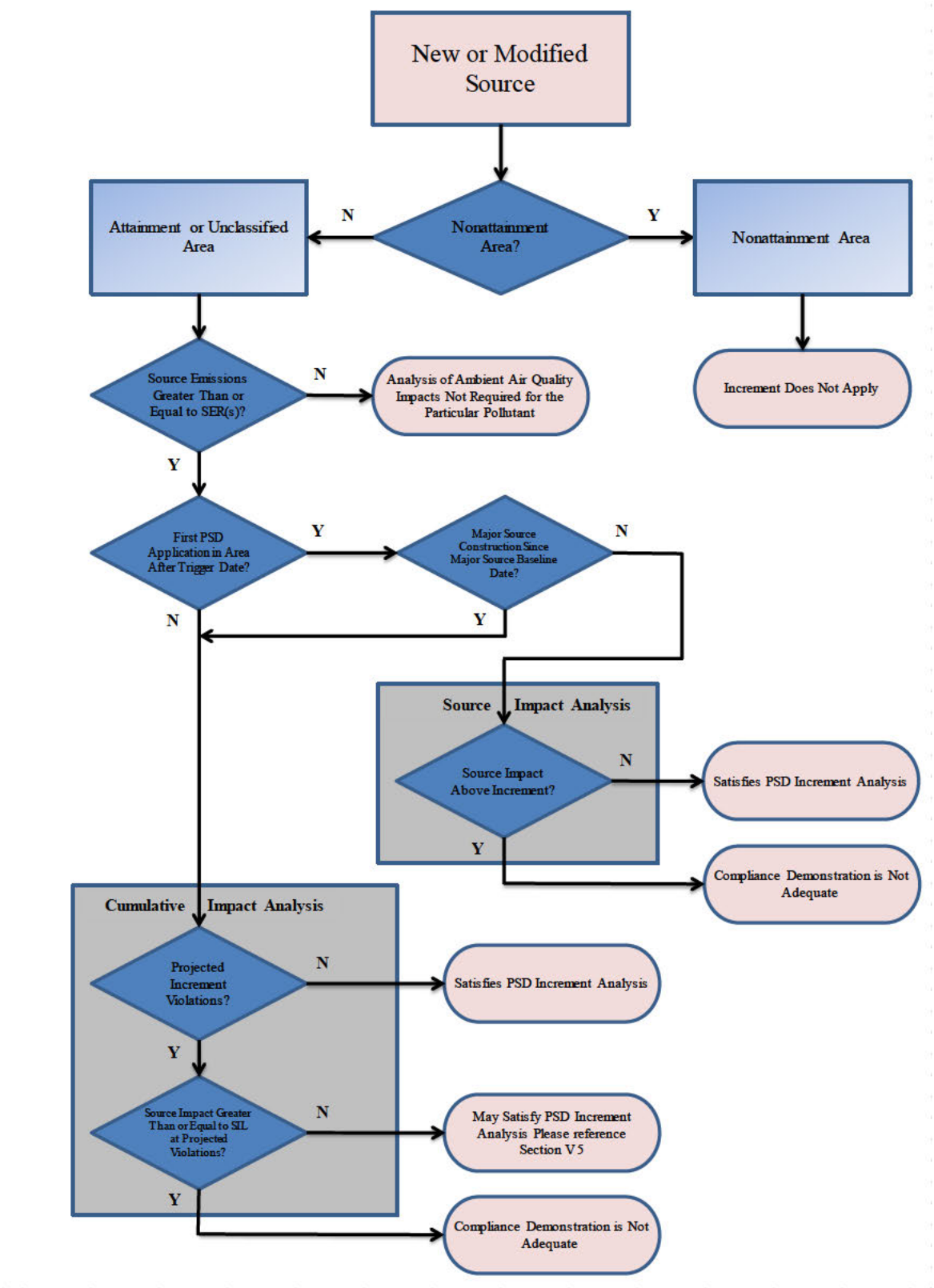


Figure II-2. Overview of PSD Increments Compliance Demonstration for New or Modifying Sources under NSR/PSD Programs



II.1 Significant Emissions Rates

EPA regulations only require an analysis of ambient air quality impacts for pollutants that a source emits (or that a modification of a source increases) in an amount equal to or greater than the significant emission rate for that pollutant defined in EPA regulations.[14] The EPA promulgated SERs for $PM_{2.5}$ and for the $PM_{2.5}$ precursors, nitrogen oxides (NO_x) and sulfur dioxide (SO_2), in 2008 as part of the first phase of PSD amendments to address $PM_{2.5}$.[15] (74 Fed. Reg. 28321 at 28333). The $PM_{2.5}$ SER for direct emissions of primary $PM_{2.5}$, defined as 10 tons per year (tpy) of direct $PM_{2.5}$ emissions, and the $PM_{2.5}$ precursor SERs, defined as either 40 tpy of NO_x or 40 tpy of SO_2, are used to determine whether any proposed new major stationary source or major modification will emit sufficient amounts of direct $PM_{2.5}$ and/or $PM_{2.5}$ precursors, i.e., equal to or above the respective SERs, to require review for $PM_{2.5}$ under the PSD program.

II.2 Screening and Source Impact Analysis

The EPA has historically supported the use of screening techniques in the PSD program to determine the extent of the air quality analysis that must be carried out to demonstrate that the source's emissions will not cause or contribute to a violation of any NAAQS or increment. [16]

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[14] See 40 CFR 51.166(m)(1)(i); 40 CFR 52.21(m)(1)(i).

[15] The EPA's final NSR rules for $PM_{2.5}$ do not require regulation of volatile organic compounds (VOC) or ammonia (NH_3) as precursors to $PM_{2.5}$ for the PSD program. However, a state may demonstrate to the Administrator's satisfaction or the EPA may demonstrate that VOC emissions in a specific area are a significant contributor to that area's ambient $PM_{2.5}$ concentrations. See 74 Fed. Reg. 28321. If so, then permit applicants with project sources having emissions of these pollutants should consult with the appropriate permitting authority and EPA Regional Office about how to deal with these emissions for the purposes of a NAAQS or PSD increments analysis.

[16] This has been consistent with overall support for screening techniques in the modeling guidelines. See, 40 CFR Part 51, Appendix W, Sections 2.2 and 4.2.1. The Guideline observes that "use of screening techniques followed, as appropriate, by a more refined analysis is always desirable." 40 CFR Part 51, Appendix W, Section 2.2.c. With respect to PSD permit review specifically, the Guideline says the following: "The purpose of [screening] techniques

Using this screening approach, when a proposed source's modeled impacts are found to be greater than the level of a SIL identified by the EPA, the EPA has called for a cumulative impact analysis (considering the combined impact of the proposed source and other sources in the affected area) to demonstrate that the proposed source will not cause or contribute to a violation of the NAAQS. On the other hand, the EPA has generally said that if the proposed source's modeled impacts are found to be below the level of a SIL identified by EPA for the relevant pollutant, this showing may be sufficient to demonstrate that the source will not cause or contribute to a modeled violation of the NAAQS.[17] However, the EPA has also acknowledged that there can be circumstances where a showing that the air quality impact of a proposed source is less than a SIL value identified by the EPA is not sufficient by itself to demonstrate that a source will not cause or contribute to a violation of the NAAQS or increment.

Prior to 2010, EPA had expressed support in guidance for applying the values in Section 51.165(b)(2) of its regulations as SILs that could be used as part of a demonstration that a source does not cause or contribute to a violation of the NAAQS. However, when the EPA added SILs for $PM_{2.5}$ in 2010 to paragraph (k)(2) of its Section 51.166 and 52.21 regulations, the Agency observed that "the use of a SIL may not be appropriate when a substantial portion of any NAAQS or increment is known to be consumed." (75 Fed. Reg. 64894). The EPA also said that "notwithstanding the existence of a SIL, permitting authorities should determine when it may be appropriate to conclude that even a *de minimis* impact will "cause or contribute" to an air quality problem and to seek remedial action from the proposed new source or modification." (75 Fed. Reg. 64892).

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is to eliminate the need of more detailed modeling for those sources that clearly will not cause or contribute to ambient concentrations in excess of either the National Ambient Air Quality Standards (NAAQS) or the allowable prevention of significant deterioration (PSD) concentration increments." *Id.* Section 2.2.a.

[17] See 72 Fed. Reg. 54112 at 54139 and 75 Fed. Reg. 64864 at 64890.

In the course of litigation challenging the SILs for $PM_{2.5}$, the EPA acknowledged that the regulatory language the EPA adopted in Sections 51.166(k)(2) and 52.21(k)(2) did not provide sufficient flexibility for permitting authorities to exercise discretion to conduct or require additional analysis in some circumstances where the EPA had advised doing so. As a result, the EPA requested that the U.S. Court of Appeals for the District of Columbia Circuit remand and vacate these provisions so the EPA could take corrective action. On January 22, 2013, the court granted this request and observed that, under the language in Sections 51.166(k)(2) and 52.21(k)(2), sources in some scenarios would not be required to demonstrate that they would not cause or contribute to a violation of the NAAQS or increments, even though, based on Petitioner's arguments, the sources likely would cause or contribute to a violation in such scenarios. The court concluded this would contravene the statutory command in Section 165(a)(3) of the Act. 705 F.3d at 464-65. The court also said that on remand the EPA may choose to promulgate regulations that "include SILs that do not allow the construction or modification of a source to evade the requirements of the Act as do the SILs in the current rule" and that such regulations would be subject to further review by the court. (Id. at 464).

EPA does not interpret the court's decision to preclude the use of SILs for $PM_{2.5}$ as part of a demonstration that a source will not cause or contribute to a violation of the $PM_{2.5}$ NAAQS. However, to ensure that PSD permitting decisions meet the requirements of the CAA, permitting authorities that continue using SILs for $PM_{2.5}$ must ensure that they select and apply such SILs in a manner that is consistent with the court's decision and the EPA's statements from the preamble of the 2010 regulation adopting SILs for $PM_{2.5}$. The EPA is developing a proposed rule to address the issues identified by the EPA and the court's decision. If necessary and as appropriate, this guidance will be amended after this rulemaking is proposed and subsequently finalized. In

the interim, permitting authorities may not apply the SIL provisions in the vacated and repealed Sections 51.166(k)(2) and 52.21(k)(2). Furthermore, permitting authorities should not apply any state regulations that have not yet been amended to conform to the repeal of these provisions and still contain regulatory text that is the same as or has a similar effect as the paragraph (k)(2) language, particularly in the types of scenarios described in the court decision and the EPA's 2010 preamble to the $PM_{2.5}$ Increments, SILs, and SMC Rule. [18] However, with appropriate safeguards, the EPA believes permitting authorities may continue to select and apply SILs values for $PM_{2.5}$ to support PSD permitting decisions and to determine the level of analysis needed to demonstrate that a source will not cause or contribute to violation of the NAAQS.[19] These safeguards involve two related considerations – the particular values of the SILs to be used and how those values are used.

The court decision does not preclude the use of SILs for $PM_{2.5}$, but requires that the EPA correct the error in the SIL regulations for $PM_{2.5}$ at 51.166(k)(2) and 52.21(k)(2). As a first step, on December 9, 2013, the EPA issued a final rule removing these sections of its regulations from the CFR (78 Fed. Reg. 73698). Until the EPA completes a rulemaking to replace these provisions, the EPA believes permitting authorities may continue to apply SILs for $PM_{2.5}$ to support a PSD permitting decision, but permitting authorities should take care to ensure that SILs are not used in a manner that is inconsistent with the requirements of Section 165(a)(3) of the CAA.

Permitting authorities have the discretion to select the particular $PM_{2.5}$ SIL values that are

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[18] Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$) – Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC). See 75 Fed. Reg. 64864 (October 20, 2010).

[19] The topic of the level of analysis needed for PSD increments compliance analysis is discussed in more detail in Section V.

used to support a permitting decision, but the values used should be supported by either a permitting record or regulation that supports the use of those values in the particular manner they are used.[20] Permitting authorities may not rely on the values contained in the vacated Sections 51.166(k)(2) and 52.21(k)(2) of the EPA's regulations as a screening tool without providing additional justification in the permitting record. However, with additional justification, it may be permissible in some cases for a permitting authority to use the same $PM_{2.5}$ SIL values as listed in the vacated Sections 51.166(k)(2) and 52.21(k)(2) to demonstrate that a full cumulative impacts analysis is not needed to make the NAAQS compliance demonstration

To the extent a permitting authority wishes to use any of the SILs values in the vacated Sections 51.166(k)(2) or 52.21(k)(2) as a screening tool to determine whether it is necessary to conduct a cumulative analysis of NAAQS compliance, the permitting authority must first examine background air quality concentrations to determine whether a substantial portion of the NAAQS has been consumed.[21] For this purpose, the EPA recommends using the preconstruction monitoring data compiled to meet the requirements of Section 51.166(m) or 52.21(m) of the EPA's regulations. If the preconstruction monitoring data are sufficiently representative of the air quality in existence before the increase in emissions from the proposed source and the difference between the $PM_{2.5}$ NAAQS and the measured $PM_{2.5}$ background concentrations in the

[20] The EPA has previously observed that the absence of an EPA-promulgated SIL does not preclude PSD permitting authorities from developing and applying SILs to support permitting decisions. *See,* Response to Comments, Implementation of New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers in Diameter ($PM_{2.5}$) at 82 (March 2008) [EPA-HQ-OAR-2003-0062-0278]. However, the EPA has also observed that, "[t]he application of any SIL that is not reflected in a promulgated regulation should be supported by a record in each instance that shows the value represents a *de minimis* impact." *See,* NO_2 NAAQS Guidance at 13; and *Mississippi Lime* at 41 (granting the petition for review where the permitting authority failed to substantiate in the record which SIL it applied and its reasons for doing so).

[21] The recent court decision vacating the $PM_{2.5}$ SMC from the PSD regulations will mean that each PSD application must include ambient monitoring data representative of the area of concern. These data need not be collected by the PSD permit applicant if existing data are determined by the permitting authority to represent the air quality in the area of concern over the 12-month period prior to the submittal of a complete PSD application.

area is greater than or equal to the SIL value selected from the vacated Sections 51.166(k)(2) and 52.21(k)(2), then the EPA believes it would be sufficient in most cases for permitting authorities to conclude that a source with an impact equal to or below that SIL value will not cause or contribute to a violation of the NAAQS and to forego a cumulative modeling analysis for $PM_{2.5}$ with respect to the NAAQS.

The above comparison of background air quality concentrations and the NAAQS would not by itself provide adequate justification for foregoing a cumulative modeling analysis for the $PM_{2.5}$ increments. Such an approach would be inappropriate because it would not ensure that there is sufficient "headroom" within the allowable increment to absorb a source contribution equal to the SIL. However, a permitting authority may still be able to justify reaching a determination that a new or modified source will not cause or contribute to a violation of the increments without performing cumulative modeling for increments.

Since the trigger date has only recently been established (i.e., October 20, 2011), for the next several years, a new or modified source being evaluated for increments compliance will often be the first source with increment-consuming emissions in the area. As indicated in Figure II-2, under this situation, a permitting authority may have sufficient reason to conclude that the impacts of the new or modified source (based on the approach for conducting source impact analysis described below) may be compared directly to the allowable increments, without the need for a cumulative modeling analysis. Such a situation would involve the new or modified source representing the first PSD application in the area after the trigger date, which establishes the minor source baseline date and baseline area, and confirmation that no relevant major source construction has already occurred since the major source baseline date.

II.3 Cumulative Impact Analysis

As part of a NAAQS compliance demonstration, a cumulative impact analysis for $PM_{2.5}$ accounts for the combined impacts of direct and precursor emissions from the new or modifying source, of direct emissions from nearby sources (as appropriate), and of monitored background levels of $PM_{2.5}$ that account for secondary $PM_{2.5}$ impacts from regional transport, secondary $PM_{2.5}$ impacts from precursor emissions from nearby sources, and primary $PM_{2.5}$ impacts from background sources not included in the modeled inventory. The cumulative impacts are then compared to the NAAQS to determine whether the source will cause or contribute to a violation of the NAAQS. Several aspects of the cumulative impact analysis for $PM_{2.5}$ will be comparable to analyses conducted for other criteria pollutants, while other aspects will differ due to the issues identified earlier.

The measured background levels incorporated into a cumulative analysis should be based on the preconstruction monitoring data gathered in accordance with the requirements of the EPA regulations. 40 CFR 51.166(m)(1)(iii)-(iv); 40 CFR 52.21(m)(1)(iii)-(iv) (2). The EPA regulations contain an exemption from the preconstruction monitoring requirements in cases where ambient concentrations or the predicted impact of the source are less than the SMC. 40 CFR 51.166(i)(5)(i) ; 40 CFR 52.21(i)(5)(i). In the decision mentioned above, a U.S. Court of Appeals vacated the SMC for $PM_{2.5}$. *Sierra Club v. EPA,* 705 F.3d 458. The court concluded that the $PM_{2.5}$ SMC provisions (51.166(i)(5)(i)(c) and 52.21(i)(5)(i)(c)) were inconsistent with the requirements of Section 165(e)(2) of the CAA. The EPA has subsequently removed the $PM_{2.5}$ SMC provisions from the regulation.[22] Thus, permitting authorities may no longer rely on the SMCs for $PM_{2.5}$ to exempt permit applicants from compiling preconstruction monitoring data for

[22] See 78 Fed. Reg. 73698.

$PM_{2.5}$ in accordance with Sections 51.166(m) and 52.21(m) of the EPA's regulation. However, the EPA believes PSD permit applicants may continue to meet the preconstruction monitoring requirements in these regulations by gathering for purposes of the permitting analysis data already available from existing monitors that are determined by the applicable permitting authority to be representative of background conditions in the affected area.[23]

Where the screening analysis described in Section II.2 above is insufficient to show that a source will not cause or contribute to a violation of the PSD increments, a cumulative impact assessment would be necessary to make the demonstration. A cumulative assessment accounts for the combined impact of the new or modifying source's emissions and those emissions changes from sources that affect the increment. The cumulative impacts are then compared to the PSD increments to determine whether the new or modifying source emissions will cause or contribute to a violation of the PSD increments.

[23] "EPA has long implemented the PSD program pursuant to the understanding that representative data may be substituted where circumstances warrant." (*In re: Northern Michigan University Ripley Heating Plant*, PSD Appeal No. 08-02, slip op. at 58 (Feb. 18, 2009));

"…the prospective PSD source must use existing … representative air quality data or collect … monitoring data." (52 Fed. Reg. 24672 (July 1, 1987) at 24686); and

With regard to the PSD requirement for monitoring data, "use of 'monitoring data' refers to either the use of existing representative air quality data or monitoring the existing air quality." (Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD), EPA-450/4-80-012, November 1980, at page 3).

II.4 Assessment Cases for Source Impacts

To support the processes shown in Figure II-1 and Figure II-2, the EPA is recommending four different assessment cases shown in Table II-1 that define which air quality analyses, *if any*, a permit applicant should conduct to demonstrate compliance with the $PM_{2.5}$ NAAQS and PSD increments.

Table II-1. EPA Recommended Assessment Cases that Define Needed Air Quality Analyses of Source Impacts

Assessment Case	Description of Assessment Case	Assess Primary Impacts of Direct $PM_{2.5}$ Emissions?	Assess Secondary Impacts of Precursor Emissions of NO_x and/or SO_2?
Case 1: No Air Quality Analysis	Direct PM2.5 emissions < 10 tpy SER NOx and SO2 emissions < 40 tpy SER	NO	NO
Case 2: Primary Air Quality Impacts Only	Direct PM2.5 emissions ≥ 10 tpy SER NOx and SO2 emissions < 40 tpy SER	**YES**	NO
Case 3: Primary and Secondary Air Quality Impacts	Direct PM2.5 emissions ≥ 10 tpy SER NOx and/or SO2 emissions ≥ 40 tpy SER	**YES**	**YES**
Case 4: Secondary Air Quality Impacts Only	Direct PM2.5 emissions < 10 tpy SER NOx and/or SO2 emissions ≥ 40 tpy SER	NO	**YES**

The four assessment cases presented in Table II-1 include:

- For "Case 1—No Air Quality Analysis," if direct $PM_{2.5}$ emissions are less than the SER of 10 tpy and both NO_x and SO_2 emissions are individually less than the respective SERs of 40 tpy, then no modeled compliance demonstration is required.[24]
- For "Case 2—Primary Air Quality Impacts Only," if the direct $PM_{2.5}$ emissions are greater than or equal to the SER of 10 tpy and both NO_x and SO_2 emissions are individually less than the respective SERs of 40 tpy, then a modeled $PM_{2.5}$

[24] See 40 CFR 51.166(m)(1)(i); 40 CFR 52.21(m)(1)(i)

compliance demonstration is required for only the direct $PM_{2.5}$ emissions based on dispersion modeling and no modeling to account for impacts of precursor emissions from the project source is necessary.

- For "Case 3—Primary and Secondary Air Quality Impacts," if the direct $PM_{2.5}$ emissions are greater than or equal to the SER of 10 tpy and NO_x and/or SO_2 precursor emissions are greater than or equal to the respective SERs of 40 tpy, then a modeled $PM_{2.5}$ compliance demonstration is required for the direct $PM_{2.5}$ emissions based on dispersion modeling and the permit applicant should also assess the potential impact of the significant precursor emissions from the project source. The accounting of the precursor emissions impact on secondary $PM_{2.5}$ formation may be: a) qualitative in nature; b) based on a hybrid of qualitative and quantitative assessments utilizing existing technical work; or c) a full quantitative photochemical grid modeling exercise. The EPA anticipates only a few situations would require explicit photochemical grid modeling.
- For "Case 4—Secondary Air Quality Impacts Only," if the direct $PM_{2.5}$ emissions are less than the SER of 10 tpy, but the NO_x and/or SO_2 precursor emissions are greater than or equal to the respective SERs of 40 tpy, then a modeled $PM_{2.5}$ compliance demonstration for the direct $PM_{2.5}$ emissions is not required, but the permit applicant should assess the potential impact of the significant precursor emissions from the project source. Similar to "Case 3," the accounting of the precursor emissions impact on secondary $PM_{2.5}$ formation may be: a) qualitative in nature; b) based on a hybrid of qualitative and quantitative assessments utilizing existing technical work; or c) a full quantitative photochemical grid

modeling exercise. Again, the EPA anticipates that only a limited number of situations would require explicit photochemical grid modeling.

Details regarding the source impact analysis and cumulative impact analysis associated with Cases 2, 3, and 4, where project emissions are equal to or greater than the respective SERs for direct $PM_{2.5}$ emissions only (Case 2), for both direct $PM_{2.5}$ and precursor emissions of NO_x and/or SO_2 (Case 3), or for precursor emissions of NO_x and/or SO_2 only (Case 4), are provided in Sections III and IV (NAAQS) and Section V (Increments).

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III. Source Impact Analysis for the $PM_{2.5}$ NAAQS

This section provides details regarding the recommended approaches for conducting the source impact analysis associated with each of the four assessment cases presented in Table III-1 so long as the SIL has been appropriately justified for use in each NAAQS compliance demonstration as described in Section II.2. In each of the assessment cases, the analysis should begin by evaluating the impacts of direct $PM_{2.5}$ emissions and/or $PM_{2.5}$ precursor emissions based upon the total amount of these emissions as compared to the respective SERs.

Table III-1. EPA Recommended Approaches for Assessing Primary and Secondary $PM_{2.5}$ Impacts by Assessment Case

Assessment Case	Description of Assessment Case	Primary Impacts Approach	Secondary Impacts Approach
Case 1: No Air Quality Analysis	Direct PM2.5 emissions < 10 tpy SER NOx and SO2 emissions < 40 tpy SER	N/A	N/A
Case 2: Primary Air Quality Impacts Only	Direct PM2.5 emissions ≥ 10 tpy SER NOx and SO2 emissions < 40 tpy SER	**Appendix W preferred or approved alternative dispersion model**	N/A
Case 3: Primary and Secondary Air Quality Impacts	Direct PM2.5 emissions ≥ 10 tpy SER NOx and/or SO2 emissions ≥ 40 tpy SER	**Appendix W preferred or approved alternative dispersion model**	• **Qualitative** • **Hybrid qualitative / quantitative** • **Full quantitative photochemical grid modeling**
Case 4: Secondary Air Quality Impacts Only	Direct PM2.5 emissions < 10 tpy SER NOx and/or SO2 emissions ≥ 40 tpy SER	N/A	• **Qualitative** • **Hybrid qualitative / quantitative** • **Full quantitative photochemical grid modeling**

A modeled NAAQS compliance demonstration is not required for Case 1 since neither direct $PM_{2.5}$ emissions nor $PM_{2.5}$ precursor (NO_x and/or SO_2) emissions are equal to or greater than the respective SERs. Case 1 is the only assessment case that does not require a modeled NAAQS compliance demonstration. Each of the remaining three assessment cases would necessitate a source impact analysis.

The simplest or most traditional assessment case is Case 2 where only direct $PM_{2.5}$

emissions are greater than or equal to the SER. For Case 2, the permit applicant would only need to demonstrate that ambient $PM_{2.5}$ impacts associated with its increase in direct $PM_{2.5}$ emissions are below a SIL based on dispersion modeling using AERMOD or other appropriate preferred model listed in Appendix A of Appendix W, or an alternative model subject to the provisions of Section 3.2 of Appendix W.

Since both direct $PM_{2.5}$ emissions and NO_x and/or SO_2 precursor emissions are equal to or greater than the respective SERs for Case 3, this will likely be the most challenging of the four assessment cases. As with Case 2, the ambient $PM_{2.5}$ impacts associated with direct $PM_{2.5}$ emissions can be estimated based on application of an appropriate preferred dispersion model for near-field $PM_{2.5}$ modeling listed in Appendix W, currently AERMOD for most applications, or an approved alternative model. However, AERMOD does not account for secondary formation of $PM_{2.5}$ associated with the source's precursor emissions. Since the source also emits quantities of $PM_{2.5}$ precursors above the respective SERs for Case 3, some assessment of their potential contribution to secondary $PM_{2.5}$ is necessary. The assessment of NO_x and/or SO_2 precursor emission impacts on secondary $PM_{2.5}$ formation may be: a) qualitative in nature; b) based on a hybrid of qualitative and quantitative assessments utilizing existing technical work; or c) a full quantitative photochemical grid modeling exercise. The EPA anticipates that only a limited number of situations would require explicit photochemical grid modeling.

Since direct $PM_{2.5}$ emissions are below the applicable SER for Case 4, the source impact analysis in this case would only address the potential contribution to secondary $PM_{2.5}$ from NO_x and/or SO_2 precursor emissions, and would not require any modeling of direct $PM_{2.5}$ emissions. As discussed above for Case 3, the assessment of the precursor emission impacts on secondary $PM_{2.5}$ formation for Case 4 may be: a) qualitative in nature; b) based on a hybrid of qualitative

and quantitative assessments utilizing existing technical work; or c) a full quantitative photochemical grid modeling exercise. As with Case 3, the EPA anticipates that only a few situations would require explicit photochemical grid modeling.

III.1 Assessing Primary $PM_{2.5}$ Impacts

The assessment of primary $PM_{2.5}$ impacts from the proposed new or modifying source is generally the same for the NAAQS and increments and should be consistent with Appendix W. As noted above, Appendix W recommends specific models as "preferred" for specific types of applications, based on model performance evaluations and other criteria. The purpose of recommending the use of a particular preferred model is to ensure that the best-performing model is used in assessing PM impacts from a particular project and is employed in a consistent fashion.[25] In 2005, the EPA promulgated AERMOD as the Agency's preferred near-field dispersion model for a wide range of regulatory applications in all types of terrain based on extensive developmental and performance evaluation.[26] For NSR/PSD modeling for the $PM_{2.5}$ NAAQS, the AERMOD modeling system should be used to model direct $PM_{2.5}$ emissions unless another preferred model is more appropriate, such as the Buoyant Line and Point source dispersion model (BLP), or the use of an alternative model can be justified consistent with Section 3.2 of Appendix W.

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[25] The best performing model is one that best predicts regulatory design values for a particular pollutant. The EPA's *Protocol for Determining the Best Performing Model* (U.S. EPA, 1992) defines appropriate methodologies and statistical criteria for this evaluation. According to the document, "For a pollutant… for which short-term ambient standards exist, the statistic of interest involves the network-wide highest concentration…the precise time, location, and meteorological condition is of minor concern compared to the magnitude of the highest concentration actually occurring."

[26] The final rule can be found at: http://www.epa.gov/scram001/guidance/guide/appw_05.pdf. Extensive documentation is available describing the various components of AERMOD, including user guides, model formulation, and evaluation papers. See EPA's SCRAM website for AERMOD documentation: www.epa.gov/scram001/dispersion_prefrec.htm#aermod

As noted in the EPA's March 23, 2010, $PM_{2.5}$ guidance memorandum, although dry and/or wet deposition may be important processes when estimating ambient concentrations of PM in general, these factors are expected to be minor for $PM_{2.5}$ due to the small particle size. In addition, there may be additional uncertainty associated with deposition modeling for $PM_{2.5}$ due to the fact that deposition properties may vary depending on the constituent elements of $PM_{2.5}$. Therefore, use of deposition algorithms to account for depletion in estimating ambient $PM_{2.5}$ concentrations should be done with caution and only when clear documentation and justification of the deposition parameters is provided.

The AERMOD modeling system includes the following components:

- AERMOD: the dispersion model (U.S. EPA, 2004a; U.S. EPA, 2014b);
- AERMAP: the terrain processor for AERMOD (U.S. EPA, 2004b, U.S. EPA, 2011a); and
- AERMET: the meteorological data processor for AERMOD (U.S. EPA, 2004c; U.S. EPA, 2014c).

Other components that may be used, depending on the application, are:

- BPIPPRIME: the building input processor (U.S. EPA, 2004d);
- AERSURFACE: the surface characteristics processor for AERMET (U.S. EPA, 2008);
- AERSCREEN: a screening version of AERMOD (U.S. EPA, 2011b; U.S. EPA, 2011c); and
- AERMINUTE: a pre-processor to calculate hourly average winds from ASOS 2-minute observations (U.S. EPA, 2011d).

Before running AERMOD, the user should become familiar with the user's guides

associated with the modeling components listed above and the most recent version of the AERMOD Implementation Guide (U.S. EPA, 2009). In addition to these documents, detailed guidance on the use of the AERMOD modeling system for estimating primary $PM_{2.5}$ impacts is provided in Appendix B. Because AERMOD is limited to modeling only direct $PM_{2.5}$ emissions, additional or alternative approaches must be used to provide an assessment of the secondary $PM_{2.5}$ impact from the proposed new or modifying source, as discussed in more detail in the following sections.

III.2 Assessing Secondary $PM_{2.5}$ Impacts

This section provides more detail on the recommended approaches for assessing the impacts of precursor emissions on secondary $PM_{2.5}$ formation for Cases 3 and 4 presented in Table III-1 including:

- a qualitative assessment;
- a hybrid of qualitative and quantitative assessments utilizing existing technical work; and
- a full quantitative photochemical grid modeling exercise.

III.2.1 Qualitative Assessments

In a number of NAAQS compliance demonstrations requiring an assessment of the impact from secondary $PM_{2.5}$ formation, it is anticipated that a holistic qualitative analysis of the new or modifying emissions source and the atmospheric environment in which the emissions source is to be located will suffice for determining that secondary $PM_{2.5}$ impacts associated with the source's precursor emissions will not cause or contribute to a violation of the 24-hour or annual $PM_{2.5}$ NAAQS. Each NAAQS compliance demonstration will be unique and may require

multiple factors to be considered and assumptions to be thoroughly justified as a part of the qualitative assessment. A well-developed modeling protocol that includes a detailed conceptual description of the current air pollution concentrations in the area (see Appendix A for examples of elements of a conceptual description) and of the nature of the emissions sources surrounding the new or modifying emissions source is paramount for determining the necessary components of an acceptable qualitative assessment of the impact from secondary $PM_{2.5}$ formation.[27] With appropriate consultation, submittal, and subsequent approval of the modeling protocol by the appropriate permitting authority, many potential problems and unintended oversights in the qualitative assessment can be resolved early in the process or avoided all together.

In the development of an appropriate conceptual description of $PM_{2.5}$ to support a qualitative assessment of the impact from secondary $PM_{2.5}$ formation, it is important to fully characterize the current $PM_{2.5}$ concentrations in the region where the new or modifying emissions source is to be located. This characterization should take into consideration not only the most current 24-hour and annual $PM_{2.5}$ design values, which would typically be used as background concentrations in a cumulative modeling demonstration, but should also include an understanding of the seasonality and speciated composition of the current $PM_{2.5}$ concentrations and any long term trends that may be occurring. Understanding whether or not $PM_{2.5}$

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[27] For more detailed information on the development of such conceptual descriptions for an area, please refer to the following:

Chapter 10 of "Particulate Matter Assessment for Policy Makers: A NARSTO Assessment." P. McMurry, M. Shepherd, and J. Vickery, eds. Cambridge University Press, Cambridge, England (NARSTO, 2004).

Section 11, "How Do I Get Started? 'A Conceptual Description'" of "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze." U.S. Environmental Protection Agency, Research Triangle Park, North Carolina (U.S. EPA, 2007a).

In addition, relevant regional examples include: "Conceptual Model of $PM_{2.5}$ Episodes in the Midwest", January 2009, Lake Michigan Air Directors Consortium; and "Conceptual Model of Particulate Matter Pollution in the California San Joaquin Valley," Document Number CP045-1-98, September 8, 1998.

concentrations are higher or lower in certain seasons or fairly uniform throughout a year and determining whether there are particular component species (e.g., sulfates, nitrates, and elemental or organic carbon) that dominate the makeup of high, low, and average $PM_{2.5}$ concentrations will help guide the degree of analysis and ultimately the justification that will be required in the qualitative assessment based on the magnitude and characteristics of any significant precursor emissions from the source. It may also be important to describe the typical background concentrations of certain chemical species that participate in the photochemical reactions that form secondary $PM_{2.5}$, such as NH_3, VOC, and ozone. It is possible that there are mitigating factors for secondary $PM_{2.5}$ formation given limitations of other chemical species important in the photochemical reactions, e.g., minimal NH_3 in the ambient environment that could limit any precursor pollutant from readily reacting to form secondary $PM_{2.5}$. The qualitative assessment should include a narrative explaining how any identified significant precursor emissions and subsequent secondary $PM_{2.5}$ formation could contribute to the existing $PM_{2.5}$ concentration environment in the region.

A good conceptual description will also characterize the meteorological conditions that are representative of the region and are associated with periods and/or seasons of higher and lower ambient 24-hour $PM_{2.5}$ concentrations. Identification of meteorological phenomena that typically occur during periods of high 24-hour $PM_{2.5}$ concentrations, such as low-level temperature inversions, stagnant high pressure systems, etc., can be extremely important in understanding the importance, or lack thereof, of photochemistry and secondary $PM_{2.5}$ formation for the higher ambient $PM_{2.5}$ concentrations. The analysis and understanding of meteorological conditions will also inform the assessment of the seasonality of the 24-hour $PM_{2.5}$ concentrations in the region. The qualitative assessment should expand upon the characterization of

meteorology described in the conceptual description to explain any meteorological factors that could limit or enhance the formation of secondary $PM_{2.5}$ from any significant precursor emissions.

Analysis of existing photochemical grid modeling developed for regional haze, ozone, and $PM_{2.5}$ SIPs or other photochemical grid modeling used in related sensitivity projects or analysis to support prior air quality rules may also be considered to help understand the general response of secondary $PM_{2.5}$ formation to certain magnitudes of a precursor pollutant in that region. While the new or modifying emissions source may emit a significant level of a precursor pollutant under PSD regulations, that level of emission may be extremely small when compared against the total emissions of that precursor pollutant throughout the region. The qualitative assessment of the impact from secondary $PM_{2.5}$ formation can be strengthened if substantial regional decreases or increases of that precursor pollutant have been demonstrated through photochemical grid modeling exercises do not cause significant decreases or increases of secondary $PM_{2.5}$.

An example of a thoroughly developed qualitative assessment of the potential for secondary $PM_{2.5}$ formation to cause or contribute to a violations of the NAAQS was provided by the EPA Region 10 Office through a response to public comments document regarding a CAA permit issued for Shell's *Discoverer* drill ship and support fleet to explore for oil and gas in the Chukchi Sea off Alaska. While the environment in and around the Chukchi Sea and North Slope of Alaska is unique when compared to the rest of the United States, the various components contained within this qualitative assessment provide a template that could be followed, with appropriate modifications, in the development of other case-specific qualitative assessments. An excerpt from this response to public comments document is provided in Appendix C.

As shown in the EPA Region 10 example, the qualitative assessment of the potential for secondary $PM_{2.5}$ formation by Shell's *Discoverer* drill ship and support fleet was developed in a narrative manner integrating numerous factors specific to the North Slope region of Alaska that provided sufficient evidence that the $PM_{2.5}$ NAAQS would not be violated in this particular case. The qualitative assessment examined the regional background $PM_{2.5}$ monitoring data and aspects of secondary $PM_{2.5}$ formation from existing sources; the relative ratio of the combined modeled primary $PM_{2.5}$ impacts and background $PM_{2.5}$ concentrations to the level of the NAAQS; the spatial and temporal correlation of the primary and secondary $PM_{2.5}$ impacts; meteorological characteristics of the region during periods of precursor pollutant emissions; the level of conservatism associated with the modeling of the primary $PM_{2.5}$ component and other elements of conservatism built into the overall NAAQS compliance demonstration; aspects of the precursor pollutant emissions in the context of limitations of other chemical species necessary for the photochemical reactions to form secondary $PM_{2.5}$; and an additional level of NAAQS protection through a post-construction monitoring requirement. While each of the components of the EPA Region 10 example may or may not be necessary, this example should provide a useful template for other qualitative assessments under this guidance, recognizing that additional components may be essential in other qualitative assessments of the potential for secondary $PM_{2.5}$ formation.

III.2.2 Hybrid Qualitative/Quantitative Assessment

The qualitative assessment discussed above is largely focused on a determination that the proposed new or modifying source precursor emissions, in combination with the estimated primary $PM_{2.5}$ impacts (if applicable for Case 3), will not cause or contribute to a violation of the

24-hour and/or annual $PM_{2.5}$ NAAQS. However, it may not always be possible to provide such a justification without some quantification of the potential secondary $PM_{2.5}$ impacts from the proposed new or modifying source's precursor emissions. In such cases, the EPA expects that existing air quality model-based information regarding the potential for SO_2 and NO_x precursor emissions to form secondary $PM_{2.5}$ concentrations may be used to establish an appropriate estimate of secondary $PM_{2.5}$ impacts from the proposed new or modifying source. As described above, there may be situations where the proposed new or modifying source's total ambient impact (i.e., primary and secondary impacts) is less than a SIL, and the record demonstrates that no further air quality assessment would be needed to demonstrate that the source would not cause or contribute to a violation of any NAAQS. Otherwise, a cumulative impact assessment would be necessary, which is discussed in Section IV.

To inform a hybrid qualitative/quantitative assessment, the existing air quality model-based information would need to be appropriate in terms of representing the type of source, its precursor emissions, and its geographic location, in addition to those elements of the conceptual description discussed above for the qualitative assessment. The quantitative modeling information may be available from past or current SIP attainment demonstration modeling, published modeling studies, or peer-review literature with estimates of model responsiveness to precursor emissions in contexts that are relevant to the new or modifying source. The estimates of model responsiveness, such as impact on $PM_{2.5}$ concentrations per ton of SO_2 emissions, could then be used in conjunction with the precursor emissions estimates for the proposed new or modifying source to provide a quantitative estimate of the impact of such precursor emissions on the formation of secondary $PM_{2.5}$ concentrations. The estimates should be technically credible in representing such impacts and it may be advisable for the estimate to reflect an upper bound of

potential impacts.

The NACAA Workgroup final report (NACAA, 2011) provides details on potential approaches to quantify the secondary $PM_{2.5}$ impacts from a proposed new or modifying source that may be appropriate to inform a hybrid qualitative/quantitative assessments of $PM_{2.5}$ impacts (See Appendix C and D of NACAA, 2011). One suggested method in the final report is to convert emissions of precursors into equivalent amounts of direct $PM_{2.5}$ emissions using "pollutant offset ratios" and then use a dispersion model to assess the impacts of the combination of direct $PM_{2.5}$ emissions and the equivalent direct $PM_{2.5}$ emissions. The "pollutant offset ratios" referenced in the final report were those put forth by the EPA in the 2008 "Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$)" final rule (73 Fed. Reg. 28321) concerning the development and adoption of interpollutant trading (offset) provisions for $PM_{2.5}$ under state nonattainment area NSR programs for $PM_{2.5}$.[28] The EPA's July 23, 2007, technical analysis titled "Details on Technical Assessment to Develop Interpollutant Trading Ratios for $PM_{2.5}$ Offsets," describes the method used to establish the original "preferred" precursor offset ratios (U.S. EPA, 2007b).

We do not support using the specific results from the EPA's 2007 technical assessment in this context without additional technical demonstration specific to the source(s) and area(s) for which the ratios would be applied. However, we expect that the EPA Regional Offices, with assistance from the OAQPS, may assist state/local air permitting agencies, as necessary, to

[28] In the preamble to the 2008 final rule (73 Fed. Reg. 28321), the EPA included preferred or presumptive offset ratios, applicable to specific $PM_{2.5}$ precursors that state/local air agencies may adopt in conjunction with the new interpollutant offset provisions for $PM_{2.5}$, and for which the state could rely on the EPA's technical work to demonstrate the adequacy of the ratios for use in any $PM_{2.5}$ nonattainment area. In a July 21, 2011 memorandum, EPA changed its policy and stated that it no longer supported the ratios provided in the preamble to the 2008 final rule as presumptively approvable ratios for adoption in SIPs containing nonattainment NSR programs for $PM_{2.5}$. Memorandum from Gina McCarthy, Assistant Administrator to Regional Air Division Directors, "Revised Policy to Address Reconsideration of Interpollutant Trading Provisions for Fine Particles ($PM_{2.5}$)" (U.S. EPA, 2011e).

structure appropriate technical demonstrations leading to the development of appropriate source and area-specific offset ratios for $PM_{2.5}$ that may be appropriate for the purposes of estimating potential secondary $PM_{2.5}$ impacts. As described in the EPA's July 21, 2011, memorandum addressing reconsideration of the interpollutant trading provisions for the 2008 final rule, the EPA acknowledged that existing models and techniques are adequate to "conduct local demonstrations leading to the development of area-specific ratios for $PM_{2.5}$ nonattainment areas" and provided a general framework for efforts that may be relevant in developing appropriate "pollutant offset ratios" for use in hybrid qualitative/quantitative assessment of secondary $PM_{2.5}$ impacts (U.S. EPA, 2011e).

An example of a hybrid qualitative/quantitative assessment of secondary $PM_{2.5}$ impacts was developed by a permit applicant, Sasol, for a major facility expansion in Southern Louisiana through close coordination with the EPA Region 6 Office and the Louisiana Department of Environmental Quality (LDEQ). Sasol and LDEQ worked closely with Region 6 to ensure that the ambient impacts analysis was robust and defendable. In this particular hybrid assessment, Sasol took an approach of using the formerly presumptive interpollutant trading ratios for NO_x and SO_2 to $PM_{2.5}$ offsets and conservatively applied them in an illustrative example to demonstrate how relatively inconsequential the impacts of secondary $PM_{2.5}$ formation would be in the area of significant impact surrounding their facility. Sasol did not seek to directly apply the formerly presumptive interpollutant trading ratios in an absolute sense. Rather, the intention was to present the analysis in a manner to determine if further technical justification would be required or if the application of the formerly presumptive interpollutant trading ratios was adequate in a hybrid qualitative/quantitative sense. A more detailed discussion of Sasol's hybrid assessment is provided in Appendix D.

The EPA also notes that the NACAA Workgroup "considered, but rejected, other methods for assessing secondary $PM_{2.5}$ impacts, including use of a simple emissions divided by distance (Q/D) metric and use of AERMOD with 100 percent conversion of SO_2 and NO_x concentrations to $(NH_4)_2SO_4$ and $(NH_4)NO_3$." The EPA has reviewed the detailed discussion provided in Appendix E of the NACAA Workgroup final report and agrees with these conclusions.

III.2.3 Full Quantitative Photochemical Grid Modeling

In those rare cases where it is deemed necessary to estimate secondary $PM_{2.5}$ impacts with full quantitative photochemical grid modeling, the candidate model for use in estimating single source impacts on secondarily formed $PM_{2.5}$ should meet the general criteria for an "alternative model" outlined in Section 3.2.2 of 40 CFR 51.112 and 40 CFR Part 51, Appendix W, for condition (3) where "the preferred model is less appropriate for the specific application, or there is no preferred model," i.e.,

i. The model has received a scientific peer review;

ii. The model can be demonstrated to be applicable to the problem on a theoretical basis;

iii. The databases that are necessary to perform the analysis are available and adequate;

iv. Appropriate performance evaluations of the model have shown that the model is not biased toward underestimates; and

iv. A protocol on methods and procedures to be followed has been established.

Section 3.2.1 of Appendix W also discusses appropriate methodologies for evaluating performance of models for regulatory applications, including the EPA's "Protocol for Determining the Best Performing Model" (U.S. EPA, 1992). The determination of acceptability of a particular model and approach for such an alternative model application is an EPA Regional Office responsibility that may also include consultation with the EPA Headquarters, if appropriate.

As noted in the NACAA Workgroup final report, photochemical grid models provide a complete characterization of emissions, chemical transformation, transport, and deposition using time and space variant meteorology. The EPA's modeling guidance for $PM_{2.5}$ attainment demonstrations (U.S. EPA, 2007a) identifies both the Comprehensive Air Quality Model with Extensions (CAMx) (ENVIRON, 2011; Nobel et al., 2001; Russell, 2008) and the Community Multiscale Air Quality (CMAQ) model (Byun and Schere, 2006; Foley et al., 2010). These state-of-the-science photochemical grid models have been used by the EPA for air quality modeling to support federal rulemaking and by state/local air permitting agencies for their air quality planning efforts. Some photochemical grid models have been instrumented with extensions that allow for the identification of impacts from specific sources to important receptor locations. These extensions generally fall in the categories of source apportionment and source sensitivity, and of sub-grid plume treatment and sampling, as described below.

Based on the current capabilities of photochemical grid models and consistent with the NACAA Workgroup report, the EPA recommends the following approaches be considered to estimate secondary $PM_{2.5}$ impacts from a proposed new or modifying source using this type of model:

- "Brute force zero-out" or difference method where two model simulations are conducted,

one with all existing sources and a second, counterfactual simulation with all existing sources and the new source emissions, with the difference being taken as the contribution from the new or modifying source.

- Instrumented techniques such as
    - Source apportionment tools where the precursor emissions from the new or modifying source are tracked to provide a contribution estimate for that individual source, or
    - Higher-order decoupled direct method (HDDM) which tracks the sensitivity of results to the emissions from a new or modifying source to provide coefficients relating source emissions to air quality response.

The NACAA Workgroup final report notes that these approaches represent fundamentally different methods and may result in different estimates for secondary $PM_{2.5}$ impacts depending on the non-linear chemical processes. The EPA, state/local permitting agencies, and others within the atmospheric modeling community continue to apply these techniques to test and evaluate their suitability for estimating single source impacts on secondarily formed $PM_{2.5}$. These efforts are critically important to inform current application of these models and techniques for purposes of assessing the secondary $PM_{2.5}$ impacts from a proposed new or modifying source, as well as to inform efforts to evaluate updates to Appendix W with new analytical techniques or models for ozone and secondary $PM_{2.5}$ per the commitments contained in the EPA's January 4, 2012, grant of the July 28, 2010, petition filed by the Sierra Club.[29]

[29] Several photochemical grid modeling approaches that allow for estimation of the secondary $PM_{2.5}$ impacts from a proposed new or modifying source were presented during the Emerging Models / Techniques Session of the 10th

Photochemical grid models that have been instrumented with source apportionment techniques track emissions from specific sources through the chemical transformation, transport, and deposition processes to estimate the source's contribution to predicted air quality at downwind receptors (Baker and Foley, 2011). Source sensitivity approaches provide information about how model predicted concentrations change based on an increase or decrease in emissions from a specific source. The difference in air quality between the original baseline simulation and the simulation where emissions are perturbed provides a quantitative estimate of that source's contribution to the cumulative impact estimate.

Another approach to differentiate the contribution of single sources on changes in model predicted air quality is the higher-order decoupled direct method (HDDM), which tracks the sensitivity of model results to emissions for a specific source through all chemical and physical processes in the modeling system (Bergin et al., 2008). Sensitivity coefficients relating source emissions to air quality are estimated during the model simulation and output at the resolution of the photochemical grid model. An important difference between source apportionment and source sensitivity is that source apportionment answers the "contribution" question, "How much did a source contribute overall to modeled air quality?" and source sensitivity answers the "responsiveness" question, "How will modeled air quality change if the source's emissions change?"

In some instances where the source and critical receptors are in very close proximity, the source and receptors may be located in the same photochemical grid model cell. Since physical and chemical processes simulated in the model represent a volume average, this may not adequately (or appropriately) represent the gradients of pollution that may exist between the

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Modeling Conference. Additional information regarding and presentations from the 10th Modeling Conference can be found on the SCRAM website at: http://www.epa.gov/ttn/scram/10thmodconf htm.

source and receptors. One approach to more explicitly represent the spatial gradient in source-receptor relationships when they are in close proximity would be to use smaller sized grid cells. Grid resolution would be defined such that the source and receptors are no longer in the same grid cell. Ideally, there would also be several grid cells between the source and receptors to best resolve near-source pollution gradients.

In these situations of close proximity between the source and receptors, a photochemical grid model instrumented with sub-grid plume treatment and sampling may be an alternative approach for characterizing these relationships. Sub-grid plume treatment extensions in photochemical grid models typically solve for in-plume chemistry and use a set of physical and chemical criteria for determination of when puff mass is merged back into the host model grid. However, accounting for source specific impacts both at the sub-grid and grid levels is challenging and enhancements to traditional implementations of this approach may be necessary to fully capture source impacts for permit applications.

For this guidance, the EPA is not prescribing in detail how photochemical grid models (or their instrumented extensions) should be applied for the purposes of conducting a NAAQS compliance demonstration since these details may involve case-specific factors that would need to be part of the consultative process with the appropriate permitting authority and reflected in the agreed-upon modeling protocol. With this in mind, we recommend that the modeling protocols for this purpose should include the follow elements:

1. Overview of Modeling/Analysis Project
    - Participating organizations
    - Schedule for completion of the project
    - Description of the conceptual model for the project source/receptor area

- Identify how modeling and other analyses will be archived and documented
- Identify specific deliverables to the appropriate permitting authority

2. Model and Modeling Inputs

- Rationale for the selection of air quality, meteorological, and emissions models
- Modeling domain
- Horizontal and vertical resolution
- Specification of initial and boundary conditions
- Episode selection and rationale for episode selection
- Rationale for and description of meteorological model setup
- Basis for and development of emissions inputs
- Methods used to quality assure emissions, meteorological, and other model inputs

3. Details on the approach for comparison to the SIL and/or NAAQS

4. Model Performance Evaluation

- Describe ambient database(s)
- Describe evaluation procedures and performance metrics

As stated previously, we expect that the EPA Regional Offices, with assistance from the OAQPS, may assist states, as necessary, to structure appropriate technical demonstrations leading to the development of appropriate photochemical grid modeling applications for the purposes of estimating potential secondary $PM_{2.5}$ impacts.

III.3 Comparison to the SIL

Where a permit applicant wishes to compare the proposed source's total ambient $PM_{2.5}$ impacts to a SIL in order to make the required demonstration that a source does not cause or contribute to a violation of the NAAQS, the compliance demonstration will vary depending on whether Case 2, 3, or 4, where direct $PM_{2.5}$ and/or precursor emissions are equal to or greater than the respective SERs, is applicable.

For Case 2, where only direct $PM_{2.5}$ emissions are equal to or greater than the applicable (10 tpy) SER, the SIL may be compared to the modeled estimates of ambient primary $PM_{2.5}$ concentrations due to direct emissions using the preferred AERMOD dispersion model (or acceptable preferred or alternative model). The modeling methods used in this initial source impact assessment phase of the $PM_{2.5}$ analysis for Case 2 are similar to the methods used for other pollutants, including the use of maximum allowable emissions, following Table 8-2 of Appendix W. However, due to the form of the $PM_{2.5}$ NAAQS, we recommend that a SIL be compared to either of the following, depending on the meteorological data used in the analysis:

- The highest of the 5-year averages of the maximum modeled 24-hour or annual $PM_{2.5}$ concentrations predicted each year at each receptor, based on 5 years of representative National Weather Service (NWS) data; or
- The highest modeled 24-hour or annual $PM_{2.5}$ concentrations predicted across all receptors based on 1 year of site-specific meteorological data, or the highest of the multi-year averages of the maximum modeled 24-hour or annual $PM_{2.5}$ concentrations predicted each year at each receptor, based on 2 or more years, up to 5 complete years of available site-specific meteorological data.

These metrics represent the maximum contribution that project emissions could make to the air

quality impact at any receptor, given the form of the NAAQS, and therefore provide an appropriate part of the basis for determining whether a cumulative modeling analysis would be needed.

For Case 3, where the source's direct $PM_{2.5}$ emissions and emissions of at least one precursor are equal to or greater than the respective SERs, the comparison of the SIL would need to address both primary and secondary $PM_{2.5}$ ambient impacts associated with the proposed source. As with Case 2, the ambient impacts due to direct $PM_{2.5}$ emissions would be estimated using the preferred AERMOD dispersion model (or acceptable alternative model). However, the comparison to the SIL will depend on the type of assessment conducted for the secondary $PM_{2.5}$ impacts from the source. As noted above, the assessment of the precursor emission impacts on secondary $PM_{2.5}$ formation may be: a) qualitative in nature; b) based on a hybrid of qualitative and quantitative assessments utilizing existing technical work; or c) a full quantitative photochemical grid modeling exercise.

Since any SIL that is used should represent a specific insignificant (or *de minimis*) ambient concentration of $PM_{2.5}$ that may be used to demonstrate that a source will not cause or contribute to a NAAQS violation without conducting a cumulative impact assessment, basing the initial source impact analysis for Case 3 on a qualitative assessment (or a hybrid of qualitative and quantitative assessments) of secondary $PM_{2.5}$ ambient impacts may be difficult to justify. This is because there would be no specific quantitative estimate of total $PM_{2.5}$ impacts for comparison to the SIL, unless a valid argument can be made that secondary $PM_{2.5}$ impacts associated with the source's precursor emissions will be very small (e.g., precursor emissions barely exceed the respective SERs and/or the chemical environment is not conducive to secondary formation). As such, when using either of these approaches, it may be appropriate to

forego the SIL assessment and focus on the NAAQS compliance demonstration using a cumulative impact analysis.

For cases where a full quantitative photochemical grid modeling assessment of secondary $PM_{2.5}$ is conducted, the SIL comparison for Case 3 should be based on the combined ambient impacts of primary and secondary $PM_{2.5}$. However, the primary and secondary $PM_{2.5}$ impacts may be combined in various ways which may entail greater or lesser degrees of conservatism. For example, combining the peak estimated primary $PM_{2.5}$ impact with the peak estimated secondary $PM_{2.5}$ impact, unpaired in time and space would likely result in a conservative estimate of combined impacts since, as noted above, peak impacts associated with a source's direct $PM_{2.5}$ and precursor emissions are not likely well-correlated in time or space. On the other hand, the conservatism associated with combining peak estimated primary and secondary impacts for comparison to a SIL would likely make such an approach easier to justify than other approaches for combining estimated primary and secondary $PM_{2.5}$ impacts.

The other extreme for combining primary and secondary $PM_{2.5}$ impacts for comparison to a SIL for Case 3, relative to combining peak primary and peak secondary impacts unpaired in time and space, would be full temporal and spatial pairing of estimated primary and secondary $PM_{2.5}$ impacts. Such an approach may not be feasible in many cases, given that the dispersion modeling and photochemical grid modeling may be based on different data periods. Furthermore, full temporal and spatial pairing of primary and secondary $PM_{2.5}$ impacts may not be appropriate in many cases due to the fact that photochemical grid modeling represents gridded concentration estimates whereas dispersion modeling produces estimates at discrete receptor locations and given the limitations in the skill of both the dispersion model and the photochemical grid model to accurately predict impacts on a paired in time and space basis. On the other hand, some degree

of temporal pairing of primary and secondary $PM_{2.5}$ impacts on a seasonal or monthly basis should be appropriate in most cases, recognizing the general lack of correlation between primary and secondary impacts.

The permitting authority and the permit applicant should thoroughly discuss the details regarding combining modeled primary and secondary $PM_{2.5}$ impacts for Case 3 and should reach agreement on a protocol during the initial review of the modeling protocol. It may be appropriate for the protocol to specifically identify multiple tiers for combining the modeled primary and secondary $PM_{2.5}$ impacts with the more conservative approaches being easier to justify. The permitting authority should ensure that any approach for combining estimated primary and secondary $PM_{2.5}$ impacts for comparison to a SIL for Case 3 conforms to the recommendations described above for Case 2 regarding the form of the modeled estimate. Accordingly, the approach should be based on the highest of the multi-year averages of the maximum modeled 24-hour or annual $PM_{2.5}$ concentrations predicted each year at each receptor, which represents the maximum contribution that the source's emissions could make in a cumulative impact assessment.

For Case 4, where the source's precursor emissions are equal to or greater than the respective SERs but direct $PM_{2.5}$ emissions are not, the SIL comparison would only address secondary $PM_{2.5}$ ambient impacts associated with the proposed source. The assessment of the precursor emission impacts on secondary $PM_{2.5}$ formation may be: a) qualitative in nature; b) based on a hybrid of qualitative and quantitative assessments utilizing existing technical work; or c) a full quantitative photochemical grid modeling exercise. As discussed above for Case 3, since a SIL should represent a specific insignificant (or *de minimis*) ambient concentration of $PM_{2.5}$ that may be used to demonstrate that a source will not cause or contribute to a violation without a

cumulative impact assessment, basing the source impact analysis on a purely qualitative assessment of secondary $PM_{2.5}$ ambient impacts or a hybrid of qualitative and quantitative assessments, utilizing existing technical work for Case 4, may be difficult to justify unless a demonstrably conservative estimate of the secondary $PM_{2.5}$ contribution can be made that is below a SIL. As such, when using either of these approaches, it may be appropriate for the permitting authority to recommend the permit applicant to forego the SIL assessment and focus on the NAAQS compliance demonstration using a cumulative impact analysis. However, it may be more feasible for the permitting authority to allow the permit applicant to apply a SIL to full photochemical grid model estimates of secondary $PM_{2.5}$ for Case 4 than for Case 3 since the issues associated with combining modeled estimates of primary and secondary $PM_{2.5}$ would not apply for Case 4. In these cases, the highest of the multi-year averages of the maximum modeled 24-hour or annual $PM_{2.5}$ concentrations predicted each year at each receptor should be compared to a SIL, since these metrics represent the maximum contribution that the source could make.

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IV. Cumulative Impact Analysis for the $PM_{2.5}$ NAAQS

Where the screening analysis described in Section II is insufficient to show that a source will not cause or contribute to a violation of the NAAQS, a cumulative impact assessment would be necessary to make the NAAQS compliance demonstration. A cumulative assessment accounts for the combined impact of the new or modifying source's emissions, emissions from other nearby sources, and representative background levels of $PM_{2.5}$ within the modeling domain. The cumulative impacts are then compared to the NAAQS to determine whether the new or modifying source emissions will cause or contribute to a violation of the NAAQS. This section provides details on conducting an appropriate cumulative impact assessment for the $PM_{2.5}$ NAAQS.

The cumulative impact assessment should include the following components of $PM_{2.5}$ impacts, as appropriate, for comparison to the NAAQS:

- Proposed new or modifying source
  - Primary impacts on $PM_{2.5}$, i.e., from direct $PM_{2.5}$ emissions
  - Secondary impacts on $PM_{2.5}$, i.e., from precursor (NO_x and/or SO_2) emissions
- Nearby sources
  - Primary impacts on $PM_{2.5}$, as appropriate
- Monitored background of $PM_{2.5}$ that accounts for secondary $PM_{2.5}$ impacts from regional transport, secondary $PM_{2.5}$ impacts from nearby sources, and primary $PM_{2.5}$ impacts from background sources not included in the modeled inventory.

As with the source impact analysis discussed previously, the primary impacts related to direct $PM_{2.5}$ emissions from the proposed new or modifying source and nearby sources should be

estimated based on the AERMOD dispersion model (or other acceptable preferred model or an approved alternative model) while the estimate of secondary $PM_{2.5}$ impacts from the proposed new or modifying source will vary depending on whether the assessment of the proposed source's precursor emission impacts on secondary $PM_{2.5}$ formation are: a) qualitative in nature; b) based on a hybrid of qualitative and quantitative assessments utilizing existing technical work; or c) based on a full quantitative photochemical grid modeling exercise. As noted above, secondary impacts on $PM_{2.5}$ from regional transport and precursor emissions from nearby sources should be accounted for through representative monitored background concentrations.

IV.1 Modeling Inventory

The current guidelines on emission inventories for purposes of NAAQS compliance modeling contained in Section 8.1 of Appendix W will generally be applicable for the $PM_{2.5}$ modeling inventory. The guidelines in Appendix W address the appropriate emission level to be modeled, which in most cases is the maximum allowable emission rate under the proposed permit. The remainder of this section will focus on the modeling inventory of direct $PM_{2.5}$ emissions that should be used in dispersion modeling of primary $PM_{2.5}$ impacts. Although the EPA's "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze" (U.S. EPA, 2007a) provides some guidance relevant to applications involving full quantitative photochemical grid modeling, additional considerations and guidance regarding modeling inventories for such analyses in support of $PM_{2.5}$ NAAQS compliance demonstrations in PSD permitting under this guidance will be provided by EPA on a case-by-case basis.

As discussed in more detail in the EPA's March 1, 2011, clarification memorandum

regarding Appendix W modeling guidelines for the 1-hour NO_2 NAAQS (U.S. EPA, 2011f), Section 8.2.3 of Appendix W emphasizes the importance of professional judgment in the identification of nearby and other sources to be included in the modeled emission inventory and establishes "a significant concentration gradient in the vicinity of the [proposed] source" as the main criterion for this selection. Appendix W also suggests that "the number of such [nearby] sources is expected to be small except in unusual situations." (Section 8.2.3.b). The EPA's March 1, 2011, guidance also includes a detailed discussion of the significant concentration gradient criterion included in Section 8.2.3.b of Appendix W, indicating that the significant concentration gradient criterion suggests that the emphasis on determining which nearby sources to include in the cumulative modeling analysis should focus on the area within about 10 kilometers of the project location in most cases. However, several application-specific factors should be considered when determining the appropriate inventory of nearby sources to include in the cumulative modeling analysis, including the potential influence of terrain characteristics on concentration gradients and the availability and adequacy of ambient monitoring data to account for background sources.

Consistent with the March 1, 2011, guidance, the EPA cautions against the application of very prescriptive procedures for identifying which nearby sources should be included in the modeled emission inventory for NAAQS compliance demonstrations, such as the procedures described in Chapter C, Section IV.C.1 of the draft "New Source Review Workshop Manual" (U.S. EPA, 1990). This caution should not be taken to imply that the procedures outlined in the draft "New Source Review Workshop Manual" are flawed or inappropriate. Cumulative impact assessments based on following such procedures will generally be acceptable as the basis for permitting decisions, contingent on an appropriate accounting for the monitored contribution.

Our main concern is that following such procedures in a literal and uncritical manner may increase the likelihood of double-counting modeled and monitored concentrations in many cases, resulting in cumulative impact assessments that are overly conservative and would unnecessarily complicate the permitting process in some cases. The identification of which sources to include in the modeled emissions inventory should be addressed in the modeling protocol and, as necessary, discussed in advance with the permitting authority.

Since modeling of direct $PM_{2.5}$ emissions has not been frequently conducted to date, the availability of an adequate direct $PM_{2.5}$ emission inventory for nearby sources may not exist in all cases. Recommendations for developing $PM_{2.5}$ emission inventories for use in PSD applications will be addressed separately, but existing SIP inventories for $PM_{2.5}$ or statewide PSD inventories of sources for refined modeling may provide a useful starting point for this effort.

IV.2 Monitored Background

Sections 8.2.2 and 8.2.3 of Appendix W provide recommendations for determination of background concentrations for inclusion in cumulative impact assessments for NAAQS compliance, which should account for impacts from existing sources that are not explicitly included in the modeled inventory and natural sources. From newly-acquired pre-construction monitoring data and/or existing representative air quality data gathered for purposes of a permitting analysis, permit applicants should assess and document what the background monitoring data represent to the extent possible, including any information that may be available

from the state or other agency responsible for siting and maintaining the monitor.[30] It is also worth noting that the relative makeup of $PM_{2.5}$ components and temporal patterns associated with the highest 24-hour $PM_{2.5}$ levels may differ considerably from the relative amounts of $PM_{2.5}$ components associated with annual average $PM_{2.5}$ levels, especially in western states.

The determination of monitored background concentrations of $PM_{2.5}$ to include in the $PM_{2.5}$ cumulative impact assessment may entail different considerations from those for other criteria pollutants and may also depend on whether the application involves full quantitative photochemical grid modeling. An important aspect of the monitored background concentration for $PM_{2.5}$ is that the ambient monitoring data should, in most cases account for the contribution of secondary $PM_{2.5}$ formation associated with existing sources impacting the modeling domain in addition to the background levels of primary $PM_{2.5}$ associated with background sources that are not included in the modeled inventory. As with other criteria pollutants, consideration should also be given to the potential for some double-counting of the impacts from modeled emissions that may be contributing to the background monitored concentrations, but this should generally be of less importance for $PM_{2.5}$ than the representativeness of the monitor for secondary contributions, unless the monitor is located relatively close to nearby sources of primary $PM_{2.5}$ that could be impacting the monitor. Also, the nature of secondary $PM_{2.5}$, monitored background concentrations of $PM_{2.5}$ are likely to be more homogeneous across the modeling domain in most cases compared to most other pollutants, although this will also depend on the potential for local sources of primary $PM_{2.5}$ to be contributing to the monitored concentrations.

Depending on the nature of local $PM_{2.5}$ levels within the modeling domain, it may be

[30] Please note in the case of an existing source seeking a permit for a modification, there is potential overlap across secondary contributions from monitored background and from precursor emission from the existing source. In such cases, recommendations for excluding monitored values when the source in question is impacting the monitor in Section 8.2.2.b of Appendix W may need to be modified to avoid overcompensating in cases where the monitored concentrations are also intended to account for the existing project source's contributions to secondary $PM_{2.5}$.

appropriate to account for seasonal variations in monitored background $PM_{2.5}$ levels which may not be correlated with seasonal patterns of the modeled primary $PM_{2.5}$ levels. For example, maximum modeled primary $PM_{2.5}$ impacts associated with fugitive or other low-level emission sources are likely to occur during winter months due to longer periods of stable atmospheric conditions, whereas maximum ambient levels of secondary $PM_{2.5}$ in the eastern United States typically occur during spring and summer months due to high levels of sulfates. The use of temporally-varying monitored background concentrations in a cumulative impact analysis is discussed in more detail in Section IV.3.

IV.3 Comparison to the NAAQS

Combining the modeled and monitored concentrations of $PM_{2.5}$ for comparison to the $PM_{2.5}$ NAAQS entails considerations that differ from those for other criteria pollutants due to the issues identified above. The discussion below addresses comparisons to the NAAQS in the context of dispersion modeling of direct $PM_{2.5}$ emissions only (for Case 2), and also provides guidance regarding NAAQS comparisons for applications involving qualitative, hybrid qualitative/quantitative, or full quantitative photochemical grid modeling assessments of secondary $PM_{2.5}$ impacts (for Cases 3 and 4).

Given the importance of secondary contributions for $PM_{2.5}$ and the potentially high background levels relative to the $PM_{2.5}$ NAAQS, greater emphasis is generally placed on the monitored background contribution relative to the modeled inventory for $PM_{2.5}$ than for other pollutants. This is true for both NAAQS and increments assessments. Also, given the probabilistic form of the $PM_{2.5}$ NAAQS, careful consideration should be given to how the monitored and modeled concentrations are combined to estimate the cumulative impact levels.

The representative monitored $PM_{2.5}$ design value, rather than the overall maximum monitored background concentration, should generally be used as the monitored component of the cumulative analysis. The $PM_{2.5}$ design value for the annual averaging period is based on the 3-year average of the annual average $PM_{2.5}$ concentrations. The $PM_{2.5}$ design value for the 24-hour averaging period is based on the 3-year average of the annual 98^{th} percentile 24-hour average $PM_{2.5}$ concentrations. Details regarding the determination of the annual 98^{th} percentile monitored 24-hour value based on the number of days sampled during the year are provided in the data interpretation procedures for the $PM_{2.5}$ NAAQS, Appendix N to 40 CFR Part 50.

It should be noted here that although the monitored design values for the $PM_{2.5}$ standards are defined in terms of 3-year averages, this definition does not preempt or alter the Appendix W requirement for use of 5 years of representative NWS meteorological data or at least 1 year of site-specific data for air quality modeling purposes. [31] The 5-year average based on use of representative NWS meteorological data, or an average across one or more (up to 5) complete years of available site-specific data, serves as an unbiased estimate of the 3-year average for purposes of modeling demonstrations of compliance with the NAAQS. Modeling of "rolling 3-year averages," using years 1 through 3, years 2 through 4, and years 3 through 5 as recommended in the EPA's "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze", is not required.[32]

The EPA's March 23, 2010, clarification memo recommended as a First Tier that the modeled annual (or 24-hour) concentrations of primary $PM_{2.5}$ to be added to the monitored

[31] See 40 CFR Part 51, Appendix W, Section 8.3.1.2.b.

[32] The "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze" can be found on the SCRAM website at: http://www.epa.gov/ttn/scram/guidance/guide/final-03-pm-rh-guidance.pdf

annual (or 24-hour) design value for comparison to the NAAQS should be based on the highest average of the modeled annual (or 24-hour) averages across 5 years for representative NWS meteorological data or the highest modeled annual (or 24-hour) average for one year (or multi-year average of 2 up to 5 complete years) of site-specific meteorological data using the same procedures recommended for the initial source impact analysis. The memo cited several issues, especially the importance of the contribution from secondary formation of $PM_{2.5}$ from precursor emissions and the fact that such contributions are not explicitly accounted for by the dispersion model, as the basis for viewing modeling of $PM_{2.5}$ as screening-level analyses, analogous to the screening nature of the guidance in Section 5.2.4 of Appendix W regarding dispersion modeling for NO_2 impacts, given the importance of chemistry in the conversion of NO emissions to ambient NO_2.

Recognizing that the primary focus and motivation for this guidance is to provide recommendations on appropriate tools and methodologies to account for the potential contribution from a new or modifying source's precursor emissions on ambient $PM_{2.5}$ levels, it is appropriate to reassess the EPA's March 23, 2010, guidance under this broadened paradigm. Since each of the four cases outlined above, based on comparisons of the project's direct $PM_{2.5}$ and precursor emissions with the respective SERs, involves some assessment of the source's potential secondary $PM_{2.5}$ impacts, we recommend as a new First Tier that the modeled design value be added to the monitored design value from a representative monitor. This represents no fundamental change with respect to the modeled annual concentration. However, the modeled 24-hour concentration to be added to the monitored design value would now be based on the multi-year average of the 98^{th} percentile of modeled annual 24-hour concentrations rather than the multi-year average of the highest (100^{th} percentile) of modeled annual 24-hour

concentrations.

For Case 2, where only the project's direct $PM_{2.5}$ emissions are equal to or greater than the SER, the modeled design value should be based on AERMOD (or other acceptable preferred or alternative model) estimates of primary $PM_{2.5}$ impacts combined with the monitored design value. The monitor should be representative in that it accounts for the contribution of secondary $PM_{2.5}$ formation associated with existing sources within the modeling domain, in addition to the background levels of primary $PM_{2.5}$ associated with background sources that are not included in the modeled inventory. For Case 3, where both the project's direct $PM_{2.5}$ emissions and precursor emissions are equal to or greater than the respective SERs, the cumulative impact for comparison to the NAAQS should be based on the sum of the modeled design value for primary $PM_{2.5}$ impacts (from dispersion model estimates based on the project's and other nearby source's direct $PM_{2.5}$ emissions), the modeled design value for secondary $PM_{2.5}$ impacts (from a qualitative, hybrid, or quantitative assessment accounting for the project's precursor $PM_{2.5}$ emissions), and the monitored design value (same representativeness caveats as with Case 2). For Case 4, where only the project's precursor emissions are equal to or greater than the respective SERs, the cumulative impact for comparison to the NAAQS should be based on the sum of the modeled design value for secondary $PM_{2.5}$ impacts (from a qualitative, hybrid, or quantitative assessment as with Case 3) and the monitored design value (same representativeness caveats as with Cases 2 and 3). The resulting cumulative $PM_{2.5}$ concentrations would then be compared to the annual $PM_{2.5}$ NAAQS of 12 $\mu g/m^3$ and 24-hour $PM_{2\,5}$ NAAQS of 35 $\mu g/m^3$.

The recommendations provided above constitute a First Tier modeling analysis for $PM_{2.5}$ NAAQS compliance demonstrations that should be acceptable without further justification. For applications where impacts from primary $PM_{2.5}$ emissions are not temporally correlated with

background $PM_{2.5}$ levels, combining the modeled and monitored contributions as described above may be overly conservative in some situations. For example, there are areas of the country where background $PM_{2.5}$ levels are substantially higher on average during the summer months as compared to the winter months; however, the projected modeled impacts from the new or modified source may be substantially greater in the winter rather than in the summer. In such cases, a Second Tier modeling analysis that would involve combining the monitored and modeled $PM_{2.5}$ concentrations on a seasonal (or quarterly) basis may be considered. The use of a seasonally-varying monitored background component is likely to be a more important factor for the 24-hour NAAQS analysis than for the annual NAAQS. Careful evaluation of when model projections of $PM_{2.5}$ impacts and background $PM_{2.5}$ levels peak throughout the year is strongly advised before embarking on a Second Tier modeling analysis. This is because the First Tier approach may adequately capture the temporal correlation and would otherwise make a Second Tier modeling analysis unnecessary. As a part of this evaluation process, consultation with the appropriate permitting authority is advised.

The AERMOD model provides several options for specifying the monitored background concentration for inclusion in the cumulative impact assessment. The options that are most relevant to $PM_{2.5}$ analyses include an option to specify a single annual background concentration that is applied to each hour of the year (appropriate for the First Tier annual and 24-hour analyses described above), and an option to specify four seasonal background values that are combined with modeled concentrations on a seasonal basis (appropriate for a Second Tier 24-hour analysis). The AERMOD model also allows the user to track the contribution from background concentrations to the cumulative modeled design value.

For the Second Tier 24-hour modeling analyses, it is recommended that the distribution

of monitored data equal to and less than the annual 98th percentile be appropriately divided into seasons (or quarters) for each of the three years that are used to develop the monitored design value. This results in data for each year (for three years) which contains one season (quarter) with the 98th percentile value and three seasons (quarters) with the maximum values which are less than or equal to the 98th percentile value. The maximum concentration from each of the seasonal (or quarterly) subsets should then be averaged across these three years of monitoring data. The resulting average of seasonal (or quarterly) maximums should then be included as the four seasonal background values within the AERMOD model. Therefore, the monitored concentrations greater than the 98th percentile in each of the three years would not be included in the seasonal (or quarterly) subsets. These excluded monitored concentrations are the same values that are excluded when determining the monitored design value. An example of the calculations for a Second Tier 24-hour modeling analysis is provided in Appendix E.

For a monitor with a daily (1-in-1 day monitor) sampling frequency and 100% data completeness, this would mean that the top seen monitored concentrations for each year would be excluded from the seasonal (or quarterly) subdivided datasets. Similarly, for a monitor with every third day (1-in-3 day monitor) sampling frequency and 100% data completeness, the top two monitored concentrations for each year would be excluded from the seasonal (or quarterly) subdivided datasets. The monitored concentrations excluded from the subdivided datasets could primarily come from one or two seasons (or quarters) each year or could be evenly distributed across all four seasons (or quarters) each year. Additionally, the monitored concentrations not included in the subdivided datasets could shift seasonally (or quarterly) from one year to the next. Given the reasoning for considering a Second Tier 24-hour analysis (lack of temporal correlation between modeled and monitored concentrations), it is likely that the monitored data

greater than the 98th percentile would be concentrated in one or two season as opposed to evenly distributed throughout the year. As mentioned earlier, one should reference Appendix N of 40 CFR Part 50 to determine the appropriate 98th percentile rank of the monitored data based on the monitor sampling frequency and valid number of days sampled during each year.

Since several recent permit applications have come to our attention proposing to combine monitored background and modeled concentrations on an hour-by-hour basis, using hourly monitored background data collected concurrently with the meteorological data period being processed by the model, we feel compelled to include a discussion of the potential merits and concerns regarding such an approach in the context of $PM_{2.5}$ NAAQS compliance demonstrations. On the surface, the hourly pairing or "paired sums" approach could be perceived as being a more “refined” method than what is recommended in the First or Second Tier methods and, therefore, more appropriate for assessing the impacts from primary $PM_{2.5}$ emissions. However, the implicit assumption underlying this approach is that the background monitored levels for each hour are spatially uniform and that the monitored values are fully representative of background levels at each receptor for each hour. Such an assumption clearly ignores the many factors that contribute to the temporal and spatial variability of ambient $PM_{2.5}$ concentrations across a typical modeling domain on an hourly basis.

The complexities of the $PM_{2.5}$ ambient monitoring network also present special challenges with a "paired sum" approach that are not present with the other NAAQS pollutants. The Federal Reference Method (FRM) $PM_{2.5}$ monitoring network is based on 24-hour samples that are taken on average every third day at the 1-in-3 day monitors. The frequency of daily or 1-in-1 day $PM_{2.5}$ monitors is steadily increasing but is relatively limited to the largest cities and metropolitan regions of the U.S. Various methods to "data fill" the 1-in-3 day monitoring

database to create a pseudo-daily dataset have been explored in a few situations , but none of these data filling methods have been demonstrated to create a representative daily $PM_{2.5}$ dataset that the EPA would consider acceptable for inclusion in a $PM_{2.5}$ NAAQS compliance demonstration. The use of continuous $PM_{2.5}$ monitors, which are more limited in number compared to the FRM monitors and may require careful quality assurance of individual hourly measurements, may be an option but should be discussed in advance with the appropriate permitting authority.

Considering the spatial and temporal variability throughout a typical modeling domain on an hourly basis and the complexities and limitations of hourly observations from the current $PM_{2.5}$ ambient monitoring network, we do not recommend a "paired sums" approach on an hour-by-hour basis. Furthermore, the pairing of daily monitored background and 24-hour average modeled concentrations is not recommended except in rare cases of relatively isolated sources where the available 1-in-1 day FRM/FEM monitor can be shown to be representative of the ambient concentration levels in the areas of maximum impact from the proposed new source. In most cases, the seasonal (or quarterly) pairing of monitored and modeled concentrations previously described in the Second Tier method should sufficiently address situations to which the impacts from primary $PM_{2.5}$ emissions are not temporally correlated with background $PM_{2.5}$ levels. Any monitor-model pairing approach aside from the First or Second Tier methods should be justified on a case-by-case basis in consultation with the appropriate permitting authority and the appropriate EPA Regional Office.

IV.4 Determining Whether Proposed Source Causes or Contributes to Modeled Violations

If the cumulative impact assessment following these recommendations results in modeled violations of the $PM_{2.5}$ NAAQS, then the permit applicant will need to determine whether the project's emissions cause or contribute to the modeled violations. The EPA has previously supported showing the proposed source does not cause or contribute by showing that the source does not make a "significant contribution" to the modeled violation based on a comparison of the modeled impacts from the project emissions associated with the modeled violation, paired in time and space, to the SIL for the relevant pollutant and averaging period contained in 40 CFR 51.165(b) of the EPA's regulations. The EPA has interpreted this regulation to support the conclusion that a source with an impact below the relevant value in section 51.165(b)(2) does not significantly contribute to either an existing violation of the NAAQS in a nonattainment area or violations predicted in an attainment area based on a cumulative analysis.[33]

The January 22, 2013, court decision did not vacate the $PM_{2.5}$ SIL value in section 51.165(b) of the EPA's regulations. However, the court recognized that the language in section 51.165(b)(2) operates in a manner different from sections 51.166(k)(2) and 52.21(k)(2), which were vacated by the court. The court observed that section 51.165(b)(2) "simply states that a source may be deemed to violate the NAAQS if its exceeds the SILs in certain situations." (705 F.3d at 465-66). For this reason, the court did not see the need to resolve the Petitioner's challenge to the EPA's methodology for determining the $PM_{2.5}$ values in section 51.165(b)(2) of the regulations, which are the same as the Class II area values in the vacated sections 51.166(k)(2) and 52.21(k)(2). The court decision did not directly address the use of the values in

[33] See 75 Fed. Reg. at 64,890; 61 Fed. Reg. 38,250, 38,293 (July 23, 1996); *In re Prairie State Generating Co.*, 13 E.A.D. 1, 103-09 (EAB 2006). EPA has sometimes described this step as a "culpability analysis."

section 51.165(b)(2) to determine whether a source causes or significantly contributes to a modeled violation. However, in light of other elements of the court decision, the EPA advises permitting authorities to consult with the EPA before using the SIL value for $PM_{2.5}$ in section 51.165(b)(2) as the basis for concluding that a source with an impact below this value does not cause or contribute to a modeled violation.

A demonstration that a proposed source does not make a significant contribution should be based on a comparison of the modeled concentrations at the receptor location showing the violation to a SIL, across 5 years for representative NWS meteorological data and the modeled concentration for 1 year, or multiyear average of 2 up to 5 complete years, of site-specific meteorological data. For a violation of the annual $PM_{2.5}$ NAAQS, the average of the predicted annual concentrations at the affected receptor(s) should be compared to a SIL, while the average of the predicted annual 98^{th} percentile 24-hour average concentrations at the affected receptor(s) should be used for the 24-hour $PM_{2.5}$ NAAQS.

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V. PSD Increments for $PM_{2.5}$

As cited in Section II of this guidance, section 165(a)(3) of the CAA requires that proposed new and modified major stationary sources seeking a PSD permit must demonstrate that their proposed emissions increases will not cause or contribute to a violation of any NAAQS or PSD increment. Based on the flow diagram presented in Figure II-2 in Section II, this section describes the EPA's recommendations for completing the required analysis of the PSD increments for $PM_{2.5}$.

V.1 Overview of PSD Increments

The term "increment" generally refers to what the CAA calls the "maximum allowable increase" of an air pollutant that is allowed to occur above the applicable baseline air quality concentration for that pollutant. Thus, by establishing the maximum allowable increase for a particular pollutant and averaging period, any cumulative increase in the ambient concentration of that pollutant that is greater than the amount allowed is considered "significant deterioration."

In order to apply the increment concept as part of a PSD permit review, it is necessary to identify the affected geographic area in which the increment will be tracked and the emissions changes that affect increment. The relevant geographic area for determining the amount of increment consumed is known as the "baseline area." [34] The baseline area may be comprised of one or more attainment or unclassifiable areas for a particular pollutant that are in a particular state. In accordance with the definition of "baseline area," the area is an "intrastate area" and does not include any area in another state. At a minimum, the baseline area is the attainment or unclassifiable area in which a PSD source will locate. Within any baseline area, three key dates

[34] "Baseline area" is defined in the PSD regulations at 40 CFR 51.166(b)(15) and 52.21(b)(15).

will apply in order to track increment: (1) trigger date; (2) minor source baseline date; and (3) major source baseline date. The trigger date is a fixed date, which is the earliest date after which proposed sources must track increment in the baseline area. In turn, the minor source baseline date is the date on which the first PSD application in a baseline area is submitted to the PSD permitting authority after the trigger date. Depending upon the number of separate attainment areas that exist for a particular pollutant in the state, there may be a number of minor source baseline dates that apply to different baseline areas established in that state. Beginning with the PSD source whose complete application has established the minor source baseline date in a particular area, any increase or decrease in actual emissions from any major or minor source henceforth will consume or expand the available PSD increments for that baseline area. Finally, the major source baseline date is a fixed date, which precedes the trigger date, after which construction related emissions solely from major stationary sources affect increment, as further explained below.

$PM_{2.5}$ emissions changes occurring before the minor source baseline date generally do not impact increment in an area, but are considered to contribute to the baseline air quality level also known as the baseline concentration, as described in more detail below. However, it is important to note that the CAA provides an exception for certain emissions changes that occur specifically at major stationary sources regardless of when those emissions changes actually occur. This date, as explained above, is the "major source baseline date." Specifically, for projects at major stationary sources on which construction commenced at a date prior to the major source baseline date, the emissions increases from such projects should be considered to contribute to the baseline air quality level even though the emissions change may not actually occur until after the minor source baseline date. Alternately, for projects at major stationary sources on which

construction commenced after the major source baseline date, the project emissions will be considered to affect increment, even if the project actually begins operation before the minor source baseline date.

V.2 $PM_{2.5}$ Increments Considerations

In its 2010 $PM_{2.5}$ Increments, SILs, and SMC Rule, the EPA established $PM_{2.5}$ increments at the levels shown in Table V-1, as follows:

Table V-1. $PM_{2.5}$ Increments

	Class I	Class II	Class III
Increments, $\mu g/m^3$			
Annual arithmetic mean	1	4	8
24-hour maximum	2	9	18

Source: Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers (PM2.5) - Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC) final rule (75 FR 64864)

The $PM_{2.5}$ increments analysis includes many of the same technical considerations in assessing source impacts as discussed earlier in this guidance for $PM_{2.5}$ NAAQS compliance demonstrations, specifically the assessment cases described in Section II-4 and detailed in Table III-1. However, there are some important differences. The main difference is that the increments compliance demonstration is based on calculating the change in ambient $PM_{2.5}$ concentrations over the applicable baseline concentration, which includes proposed emissions increases from the new or modified source, increment-consuming emissions from other sources that affect increment consumption in the baseline area, and increment-expanding decreases in emissions from the same sources. Another key difference is that the cumulative impact analysis for increments is based on the actual emission changes occurring after a prescribed minor source baseline date (with the stated exception related to major sources commencing construction after

the major source baseline date), whereas NAAQS analyses are generally based on the cumulative impact associated with the maximum allowable emissions from the new or modifying source and other nearby sources. Finally, it is important to note that the $PM_{2.5}$ NAAQS and increments for the 24-hour averaging period are defined in different forms and therefore must be analyzed differently.[35] The 24-hour $PM_{2.5}$ NAAQS is defined based on the 3-year average of the annual 98^{th} percentile of the 24-hour average concentrations, while the 24-hour $PM_{2.5}$ increments are based on the second highest maximum 24-hour concentration.

The 2010 "$PM_{2.5}$ Increments, SILs, and SMC Rule" established October 20, 2011, as the "trigger date" and October 20, 2010, as the "major source baseline date" for $PM_{2.5}$ increments. The EPA developed the increment system for $PM_{2.5}$ generally following the same concepts that were previously applied for the increments for PM_{10}, SO_2, and NO_2. In each case, the framework reflects the statutory concepts set forth in the definition of "baseline concentration" contained in the CAA at section 169(4), which reads as follows:

> The term "baseline concentration" means, with respect to a pollutant, the ambient concentration levels which exist at the time of the first application for a permit in an area subject to this part, based on air quality data available in the Environmental Protection Agency or a State air pollution control agency and on such monitoring data as the permit applicant is required to submit. Such ambient concentration levels shall take into account all projected emissions in, or which may affect, such area from any major emitting facility on which construction commenced prior to January 6, 1975, but which has not begun operation by the date of the baseline air quality concentration determination (i.e., the minor source baseline date). Emissions of sulfur oxides and particulate matter from

[35] The annual NAAQS and increments for $PM_{2.5}$ are both measured as annual arithmetic mean values.

> any major emitting facility on which construction commenced after January 6, 1975, shall not be included in the baseline and shall be counted against the maximum allowable increases in pollutant concentrations established under this part.

Thus, from this definition, it can be seen that it is conceptually possible to measure "significant deterioration" in at least two separate ways. That is, either as (1) a direct modeled projection of the change in air quality after the applicable baseline date caused by all increment-consuming or expanding emissions compared to the maximum allowable increase of the air pollutant concentration (increment) in the baseline area, or (2) a determination of whether the ambient air quality concentration in a baseline area will exceed an allowable ambient air quality ceiling, determined by adding the maximum allowable pollutant concentration increase (increment) to the baseline air quality concentration (baseline concentration) for the baseline area.

Historically, because of various limitations associated with the use of ambient air quality monitoring data for measuring increment consumption,[36] the EPA elected to determine significant deterioration exclusively on the basis of the first approach, which models only the increment-related emissions increases or decreases to determine the resulting ambient air quality change and compares this value with maximum allowable pollutant concentration increases (increments) for a particular pollutant. However, the present technical challenges associated with the ability to estimate the impacts of secondarily formed $PM_{2.5}$ in the atmosphere resulting from emissions of $PM_{2.5}$ precursors make it necessary to consider alternative methods of assessing increments where the increments are affected by both direct $PM_{2.5}$ emissions and $PM_{2.5}$ precursor

[36] The EPA described certain limitations associated with the use of ambient air quality monitoring data for measuring increment consumption in the preamble to its proposed PSD regulations in 1979. For example, the CAA provided that certain emissions changes should not be considered to be increment consuming. These limitations generally continue to apply to the extent that certain emissions changes detected by an ambient monitor are not considered to consume increment. See 44 Fed. Reg. 51924 at 51944 (September 5, 1979).

emissions that form secondary $PM_{2.5}$. Accordingly, the remainder of this section provides recommendations for accomplishing the $PM_{2.5}$ increments analysis.

V.3 Screening Analysis for Increments

The comparison of background air quality concentrations and the NAAQS, as recommended in Section II of this document as an initial step for the NAAQS compliance demonstration, would not by itself provide adequate justification for foregoing a cumulative modeling analysis for the $PM_{2.5}$ increments. Such an approach would be inappropriate because it would not ensure that there is sufficient "headroom" within the allowable increment to absorb a source contribution equal to the SIL. However, a permitting authority may still be able to justify reaching a determination that a new or modified source will not cause or contribute to a violation of the increments without performing cumulative modeling for increments.

The EPA recommends that a justification for not performing cumulative modeling for $PM_{2.5}$ increments compliance should be based on (1) a comparison of the predicted impacts of the new or modified source and the allowable increment values, (2) information on the extent to which, if any, increment has already been consumed since either the major source baseline date (for major source construction prior to the minor source baseline date) or minor source baseline date by nearby sources that have been permitted prior to the source under analysis, and (3) information on increment consumption or expansion by more distant sources.

Since the trigger date has only recently been established (i.e., October 20, 2011), for the next several years a new or modified source being evaluated for increments compliance will often be the first source with increment-consuming emissions in the area. As indicated in Figure II-2, under this situation, a permitting authority may have sufficient reason to conclude that the

impacts of the new or modified source (based on the approach for conducting source impact analysis described below) may be compared directly to the allowable increments, without the need for a cumulative modeling analysis. Such an approach would be appropriate when the new or modified source represents the first PSD application in the area after the trigger date, which establishes the minor source baseline date and baseline area, and no relevant major source construction has already occurred since the major source baseline date.

V.4 $PM_{2.5}$ Increments Analysis

The guidance provided under Sections III and IV regarding NAAQS compliance demonstrations should generally be applicable for $PM_{2.5}$ increments analyses, with the primary distinction that actual emission increases (or decreases) from only increment-affecting sources may be used instead of maximum allowable emissions in the cumulative impact analysis.

V.4.1 Source Impact Analysis

The EPA's recommendations on conducting the source impact analysis for $PM_{2.5}$ increments rely upon the same four assessment cases for NAAQS, as described in Section II.4. As shown in Table V-2, a modeled compliance demonstration is not required for Case 1 since neither direct $PM_{2.5}$ emissions nor $PM_{2.5}$ precursor (NO_x and/or SO_2) emissions are equal to or greater than the respective SERs. Case 1 is the only assessment case that does not require a modeled compliance demonstration for $PM_{2.5}$, whereas each of the remaining three assessment cases would necessitate a source impact analysis that should be conducted following the detailed recommendations provided in Section III for NAAQS analysis.

Table V-2. EPA Recommended Approaches for Assessing Primary and Secondary $PM_{2.5}$ Impacts by Assessment Case

Assessment Case	Description of Assessment Case	Primary Impacts Approach	Secondary Impacts Approach
Case 1: No Air Quality Analysis	Direct PM2.5 emissions < 10 tpy SER NOx and SO2 emissions < 40 tpy SER	N/A	N/A
Case 2: Primary Air Quality Impacts Only	Direct PM2.5 emissions ≥ 10 tpy SER NOx and SO2 emissions < 40 tpy SER	**Appendix W preferred or approved alternative dispersion model**	N/A
Case 3: Primary and Secondary Air Quality Impacts	Direct PM2.5 emissions ≥ 10 tpy SER NOx and/or SO2 emissions ≥ 40 tpy SER	**Appendix W preferred or approved alternative dispersion model**	• **Qualitative** • **Hybrid qualitative / quantitative** • **Full quantitative photochemical grid modeling**
Case 4: Secondary Air Quality Impacts Only	Direct PM2.5 emissions < 10 tpy SER NOx and/or SO2 emissions ≥ 40 tpy SER	N/A	• **Qualitative** • **Hybrid qualitative / quantitative** • **Full quantitative photochemical grid modeling**

V.4.2 Cumulative Impact Analysis

Where the screening analysis described above is insufficient to show that a source will not cause or contribute to a violation of the PSD increments, a cumulative impact assessment would be necessary to make the demonstration. A cumulative assessment accounts for the combined impact of the new or modifying source's emissions and those emissions changes from sources that affect the increments. The cumulative impacts are then compared to the PSD increments to determine whether the new or modifying source emissions will cause or contribute to a violation of the PSD increments. This section provides details on conducting an appropriate cumulative impact assessment for $PM_{2.5}$.

V.4.2.1 Assessing Primary $PM_{2.5}$ Impacts from Other Sources

To assess direct $PM_{2.5}$ emissions from increment-consuming or increment-expanding sources, the $PM_{2.5}$ increments analysis would follow the traditional approach involving modeling of only $PM_{2.5}$ emissions changes that affect the increment, and should be based on application of

AERMOD (or other appropriate preferred or approved alternative model), using actual emission changes associated with any increment-consuming or increment-expanding sources. The AERMOD model allows for inclusion of these emissions (represented as negative emissions for the sources expanding increment) in the same model run that includes the allowable increase in emissions from the project source, and will therefore output the net cumulative concentrations (although the "maximum" cumulative impacts will be output as zero if the cumulative impacts computed in the model are less than zero).

V.4.2.2 Assessing Secondary $PM_{2.5}$ Impacts from Other Sources

To assess changes in $PM_{2.5}$ precursor emissions from increment-consuming or increment-expanding sources, the assessment of potential impacts of secondary $PM_{2.5}$ due to those emissions changes may be: a) qualitative in nature; b) based on a hybrid of qualitative and quantitative assessments utilizing existing technical work; or c) a full source-specific quantitative photochemical modeling exercise.

Several promulgated rules have resulted in reductions in precursor emissions affecting ambient $PM_{2.5}$ concentrations across most areas in recent years.[37] This is particularly true in the Eastern U.S. As a result, in many cases, the potential for increment consumption due to secondary $PM_{2.5}$ impacts from existing sources may easily be addressed through a qualitative assessment, supported by data that generally confirms a downward trend in precursor emissions occurring after the applicable $PM_{2.5}$ minor source baseline date (or the major source baseline date). In such cases, the $PM_{2.5}$ increments modeling analysis may be simplified to focus solely on potential increment consumption associated with direct $PM_{2.5}$ emissions. For areas where $PM_{2.5}$

[37] Such rules would include the Clean Air Interstate Rule (CAIR), Mercury and Air Toxics Standards Rule (MATS), NOx SIP Call and multiple federal mobile source rules.

precursor emissions increases from other sources are known to contribute to $PM_{2.5}$ concentration increases within the baseline area and thus consume $PM_{2.5}$ increment, the photochemical grid modeling methods discussed in Section III may be appropriate for estimating the portion of $PM_{2.5}$ increment consumed due to secondary $PM_{2.5}$ impacts associated with those increases in precursor emissions.

V.4.2.3 Consideration of $PM_{2.5}$ Ambient Air Quality Monitoring Data

In light of the current technical complications associated with the ability to model precursor emissions to estimate secondarily formed $PM_{2.5}$ in the atmosphere, the EPA believes it may be possible under certain circumstances to use ambient air quality monitoring data for $PM_{2.5}$ as part of the cumulative impact analysis. This involves using ambient monitoring data as the primary means of assessing increment consumption or expansion for $PM_{2.5}$ by measuring ambient air quality on the minor source baseline date (baseline concentration) and thereafter to determine changes in air quality resulting from direct $PM_{2.5}$ emissions and $PM_{2.5}$ precursors. This document does not provide detailed recommendations for conducting the $PM_{2.5}$ increments analysis in this manner, but simply acknowledges that it may be possible in certain circumstances to use this approach for PSD permitting. There would continue to be a need to model projected impacts as part of the $PM_{2.5}$ increments analysis to include consideration of increment consumed by emissions that have not yet occurred. One should also consider the extent to which the available monitoring data adequately reflect the air quality changes caused by direct $PM_{2.5}$ and precursor emissions from sources impacting the baseline area.

Where the PSD permit applicant believes that this approach is potentially useful for conducting the $PM_{2.5}$ increments analysis for a particular PSD permit review, early coordination

with the permitting authority is strongly encouraged to establish the appropriate baseline concentration(s) within the applicable baseline area and how subsequent ambient monitoring data in the area, when compared to the baseline air quality data, can be used to assess cumulative increment consumption. The EPA will work with air agencies to support this approach on a case specific basis. Based on these experiences, it is our intention to provide additional guidance setting forth more specific recommendations on this particular approach at a future date.

V.5 Determining Significant Contribution to an Increment Violation

As previously explained, the EPA does not anticipate the need to complete a cumulative increments analysis in most situations due to the recent setting of the trigger date for $PM_{2.5}$. Therefore, most $PM_{2.5}$ increments analyses will need to consider the emissions increases resulting only from the proposed new source or modification that establishes the minor source baseline date for an area. Consequently, we believe that permitting authorities will encounter few, if any, situations over the next several years in which there is a predicted increment violation.

Nevertheless, there may be situations where a cumulative increments analysis is necessary and that analysis projects a modeled increment violation. This guidance recommends that such violations be addressed in a manner similar to the NAAQS analysis described in Section IV of this document; that is, when a PSD applicant elects to use a SIL to show to the permitting authority that the source's emissions do not make a significant contribution to a modeled violation, the EPA advises permitting authorities to consult with the EPA before allowing the use of a SIL value, including those $PM_{2.5}$ values contained in section 51.165(b)(2), as the basis for concluding that a source with an impact below this value does not cause or

contribute to a modeled violation of the $PM_{2.5}$ increment.

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Appendix A: Draft Conceptual Description of $PM_{2.5}$ Concentrations in the U.S.

This appendix provides a brief summary of the current $PM_{2.5}$ monitoring networks and characterizes PM air quality in terms of its chemical composition, concentration levels, and spatial and temporal patterns across the nation based largely on ambient data and analyses contained in the EPA's The Particle Pollution Report,[38] Particulate Matter Staff Paper,[39] and new ambient data summaries based on 2008-2010 $PM_{2.5}$ mass and speciation data. It also discusses regional and local source contributions to urban $PM_{2.5}$ concentrations. Such information may be useful for permit applicants in preparing conceptual descriptions, as discussed in Section III.2.1 of this guidance.

1. $PM_{2.5}$ Monitoring Networks

1.1. $PM_{2.5}$, PM_{10} and $PM_{10-2.5}$ Mass Networks

The 1997 promulgation of a fine particulate NAAQS (EPA, 1997) led to deployment of over 1500 $PM_{2.5}$ sites (about 1000 currently) used to determine whether an area complies with the standard. These sites use a Federal Reference Method (FRM) or Federal Equivalent Method (FEM), daily sampling over 24-hours, or every third or sixth day. Nearly 300 additional measurements not meeting FRM or FEM specifications are provided by the chemical speciation sites (Figure A-1). Approximately 600 stations provide indirect measurements of continuous (hourly resolution) $PM_{2.5}$ mass using a variety of techniques.

1.2. Interagency Monitoring of Protected Visual Environments (IMPROVE) Program

The IMPROVE network, with over 100 sites, has provided nearly a two-decade record of major components of $PM_{2.5}$ (sulfate, nitrate, organic and elemental carbon fractions, and trace metals) in pristine areas of the United States (Figure A-1). IMPROVE is led by the National Park Service; various federal and state agencies support its operations. The primary focus of the network is to track visibility and trends in visibility.

1.3. $PM_{2.5}$ Chemical Speciation Monitoring

In addition to the IMPROVE network, over 300 EPA speciation sites were added from 2000 - 2002 in urban areas of the United States to assist $PM_{2.5}$ assessment efforts. No FRM exists for particulate speciation, which is not directly required to determine attainment, and there are slight differences between monitors and methods used in the Speciation Trends Network (STN). However, the network's coverage (Figure A-1) across urban and rural areas has proved essential for a wide range of research and analysis. The speciation networks typically collect a 24-hour sample every three, and sometimes six, days.

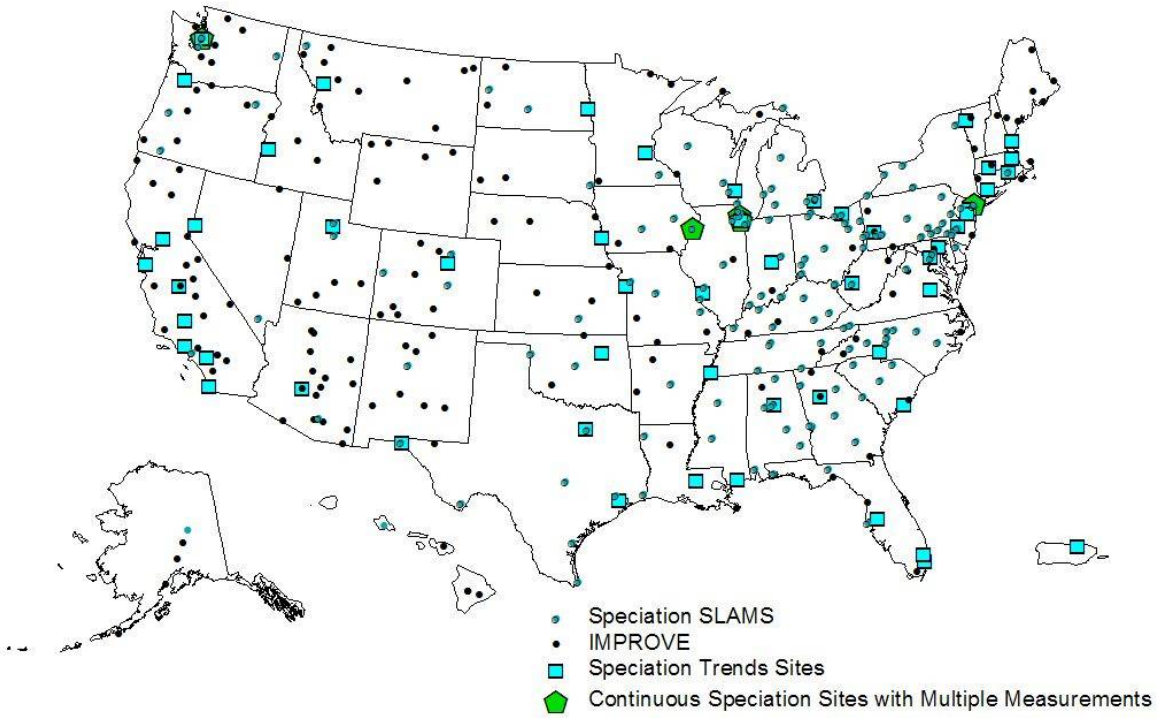
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[38] The Particle Pollution Report: Current Understanding of Air Quality and Emissions through 2003. http://www.epa.gov/airtrends/aqtrnd04/pmreport03/pmcover_2405.pdf#page=1.

[39] Particulate Matter Staff Paper: Review completed in 2012. http://www.epa.gov/ttn/naaqs/standards/pm/s_pm_cr_sp.html.

Daily 24-hour speciation collection is limited to occasional efforts in the SEARCH (see below) network. Similarly, only a handful of sites provide near continuous speciation data, usually limited to some combination of sulfate, carbon (organic and elemental splits) and nitrate. This enables insight to diurnal patterns for diagnosing various cause-effect phenomena related to emissions characterization, source attribution analysis and model evaluation.

Figure A-1. Locations of chemical speciation sites delineated by program type



1.4. South Eastern Aerosol Research and Characterization (SEARCH) Study

This study experiment is an industry-funded network of 8 sites that originally emerged from the Southern Oxidants Study (SOS) in the 1990s and has operated for over a decade in response to the 1997 revisions to the national ambient air quality standards for ground-level ozone and particulate matter. SEARCH is part of a public-private collaboration that provides an array of standard criteria pollutant measurements but also includes daily 24-hour PM speciation at selected times and locations, gaseous ammonia, reactive nitrogen (NO_y), and true nitrogen dioxide (i.e., a measurement of NO_2 concentration unaffected by other nitrogen oxides, which contaminate FRM NO_2 measurements). These measurements had not been available in major government-funded routine networks and in order to identify sources of ozone precursors and fine particulate matter and to attribute health effects to specific components, the SEARCH project sponsors believe that it is necessary to measure pollutant composition as well as mass.

1.5. PM Supersites Program

This program provided highly resolved aerosol measurements at eight U.S. cities for several time periods from 1999 through 2004, with some sites collecting data after 2004.[40] A number of instrument configurations were deployed, ranging from additional locations for standard speciation monitors, to systems capturing near-continuous size-dependent speciation profiles.

2. Composition of $PM_{2.5}$

Particulate matter (PM) is a highly complex mixture of solid particles and liquid droplets distributed among numerous atmospheric gases which interact with solid and liquid phases. Particles range in size from those smaller than 1 nanometer (10^{-9} meter) to over 100 microns (1 micron is 10^{-6} meter) in diameter (for reference, a typical strand of human hair is 70 microns and particles less than about 20 microns generally are not detectable by the human eye). Particles are classified as $PM_{2.5}$ and $PM_{10-2.5}$, corresponding to their size (diameter) range in microns and referring to total particle mass under 2.5 and between 2.5 and 10 microns, respectively.

Particles span many sizes and shapes and consist of hundreds of different chemicals. Particles are emitted directly from sources and also are formed through atmospheric chemical reactions and often are referred to as primary and secondary particles, respectively. Particle pollution also varies by time of year and location and is affected by several aspects of weather such as temperature, clouds, humidity, and wind. Further complicating particles is the shifting between solid/liquid and gaseous phases influenced by concentration and meteorology, especially temperature.

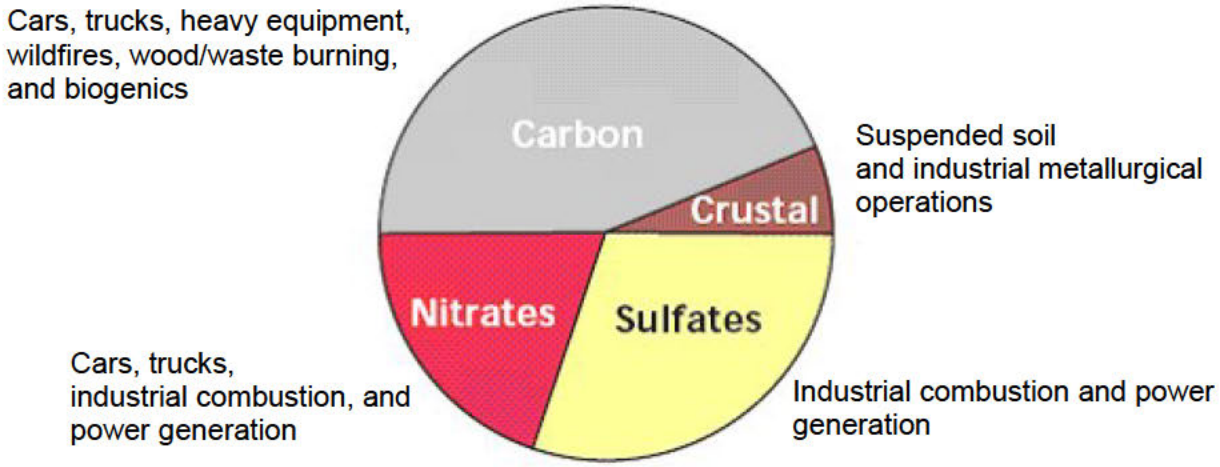
Particles are made up of different chemical components. The major components, or species, are carbon, sulfate and nitrate compounds, and crustal materials such as soil and ash (Figure A-2). The different components that make up particle pollution come from specific sources and are often formed in the atmosphere. Particulate matter includes both “primary” PM, which is directly emitted into the air, and “secondary” PM, which forms indirectly from fuel combustion and other sources. Primary PM consists of carbon (soot)—emitted from cars, trucks, heavy equipment, forest fires, and burning waste—and crustal material from unpaved roads, stone crushing, construction sites, and metallurgical operations. Secondary PM forms in the atmosphere from gases. Some of these reactions require sunlight and/or water vapor. Secondary PM includes:

- Sulfates formed from sulfur dioxide emissions from power plants and industrial facilities;
- Nitrates formed from nitrogen oxide emissions from cars, trucks, industrial facilities, and power plants; and

[40] Solomon, P.A., P.K. Hopke, J. Froines, and R. Scheffe, 2008: Key Scientific and Policy and Health-Relevant Findings from the U.S. EPA’s Particulate Matter Supersites Program and Related Studies: An Integration and Synthesis of Results, J. Air & Waste Manage. Assoc., 58, S-1 – S-92.

- Carbon formed from reactive organic gas emissions from cars, trucks, industrial facilities, forest fires, and biogenic sources such as trees.

Figure A-2. National Average of Source Contribution to Fine Particle Levels



Source: The Particulate Matter Report, EPA-454-R-04-002, Fall 2004. Carbon reflects both organic carbon and elemental carbon. Organic carbon accounts for automobiles, biogenics, gas-powered off-road, and wildfires. Elemental carbon is mainly from diesel powered sources.

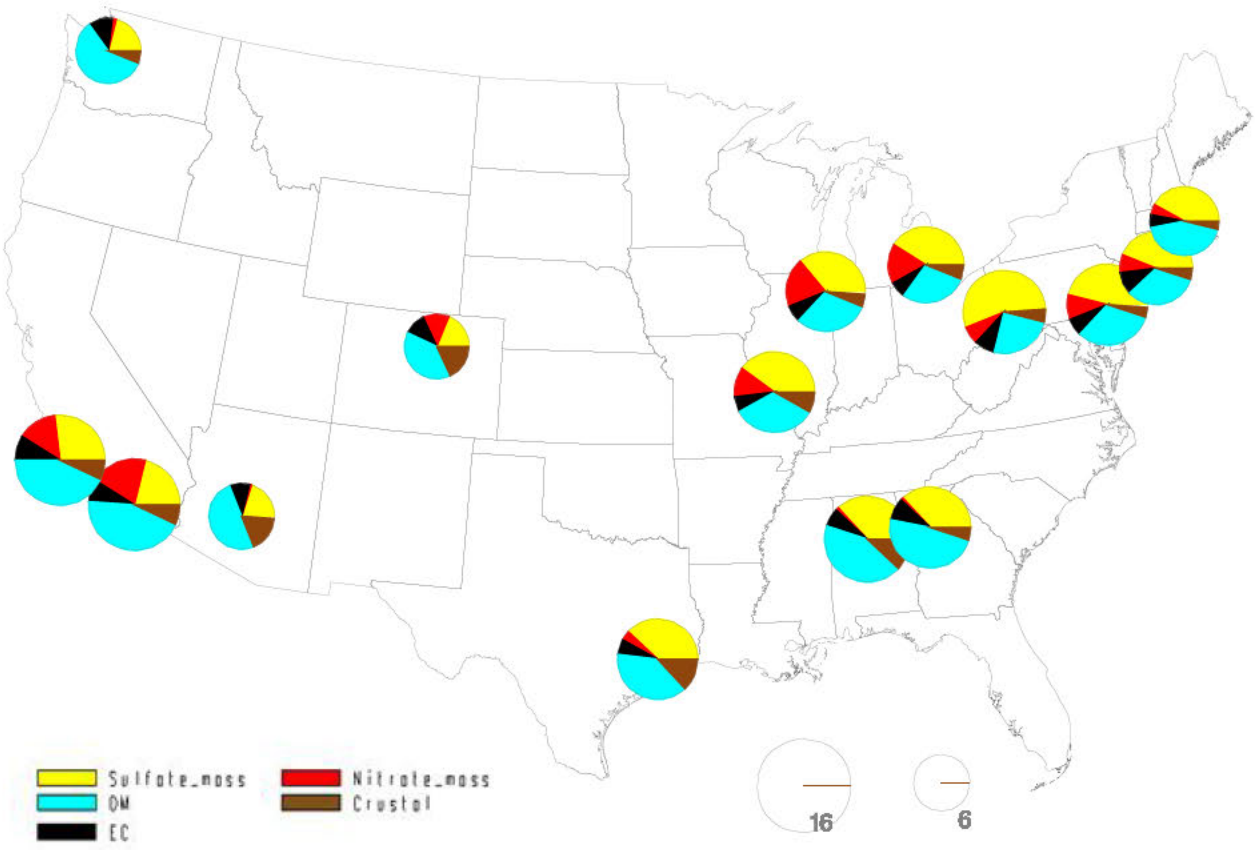
In addition, ammonia from sources such as fertilizer and animal feed operations contributes to the formation of sulfates and nitrates that exist in the atmosphere as ammonium sulfate and ammonium nitrate. Note that fine particles can be transported long distances by wind and weather and can be found in the air thousands of miles from where they were formed.

The chemical makeup of particles varies across the United States (as shown in Figure A-3).[41] For example, fine particles in the eastern half of the United States contain more sulfates than those in the West, while fine particles in southern California contain more nitrates than other areas of the country. Organic carbon is a substantial component of fine particle mass everywhere. This figure represents the composition of $PM_{2.5}$ as measured by the $PM_{2.5}$ FRM.[42]

[41] The 15 cities are the same ones included in the Integrated Science Assessment for Particulate Matter (2009) which includes a similar map based on 2005-2007 $PM_{2.5}$ data.

[42] Frank, N. H., Retained Nitrate, Hydrated Sulfates, and Carbonaceous Mass in Federal Reference Method Fine Particulate Matter for Six Eastern U.S. Cities, 'J. Air & Waste Manage. Assoc.' 2006, '56', 500-511.

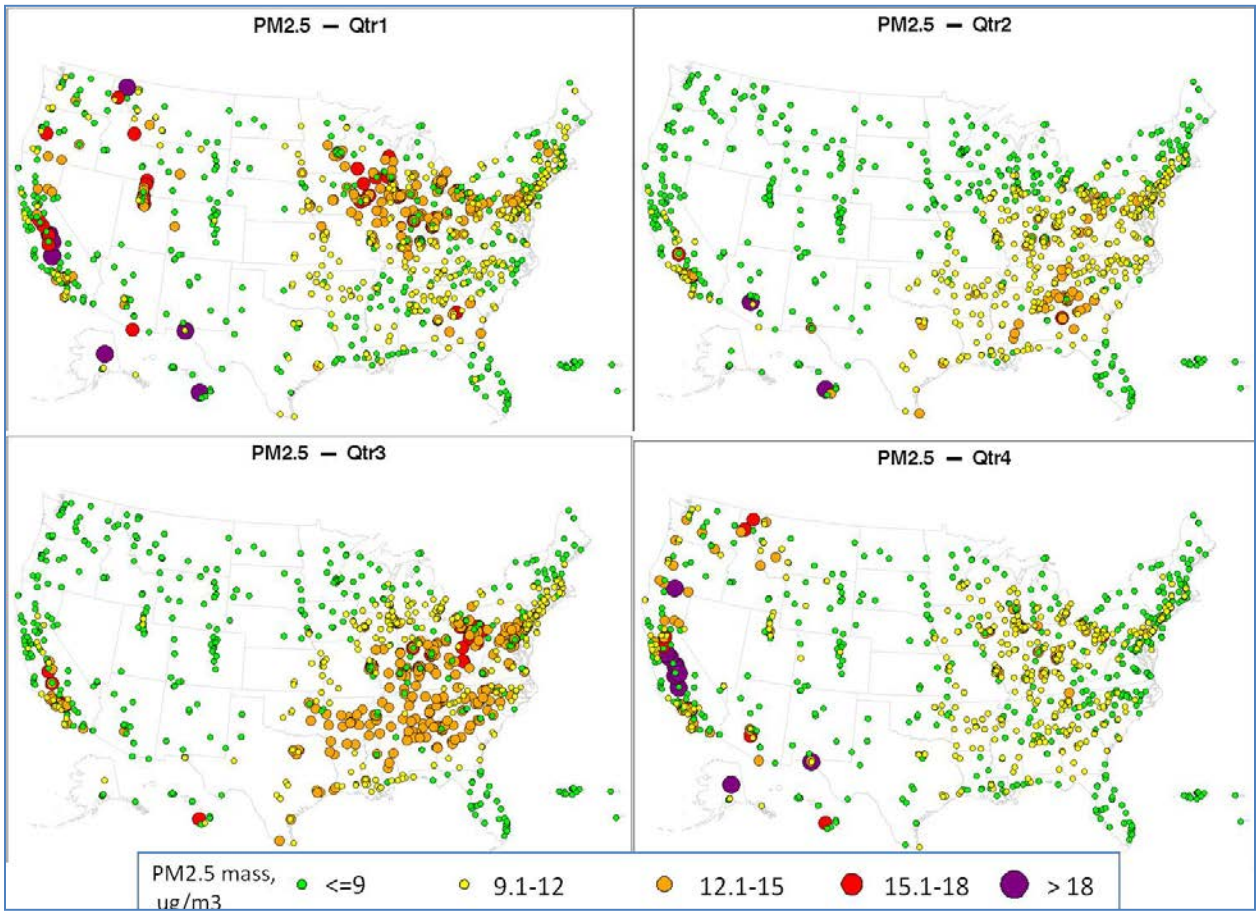
Figure A-3. Annual Average $PM_{2.5}$ Composition in 15 Urban Areas: 2008-2010



3. Seasonal and Daily Patterns of $PM_{2.5}$

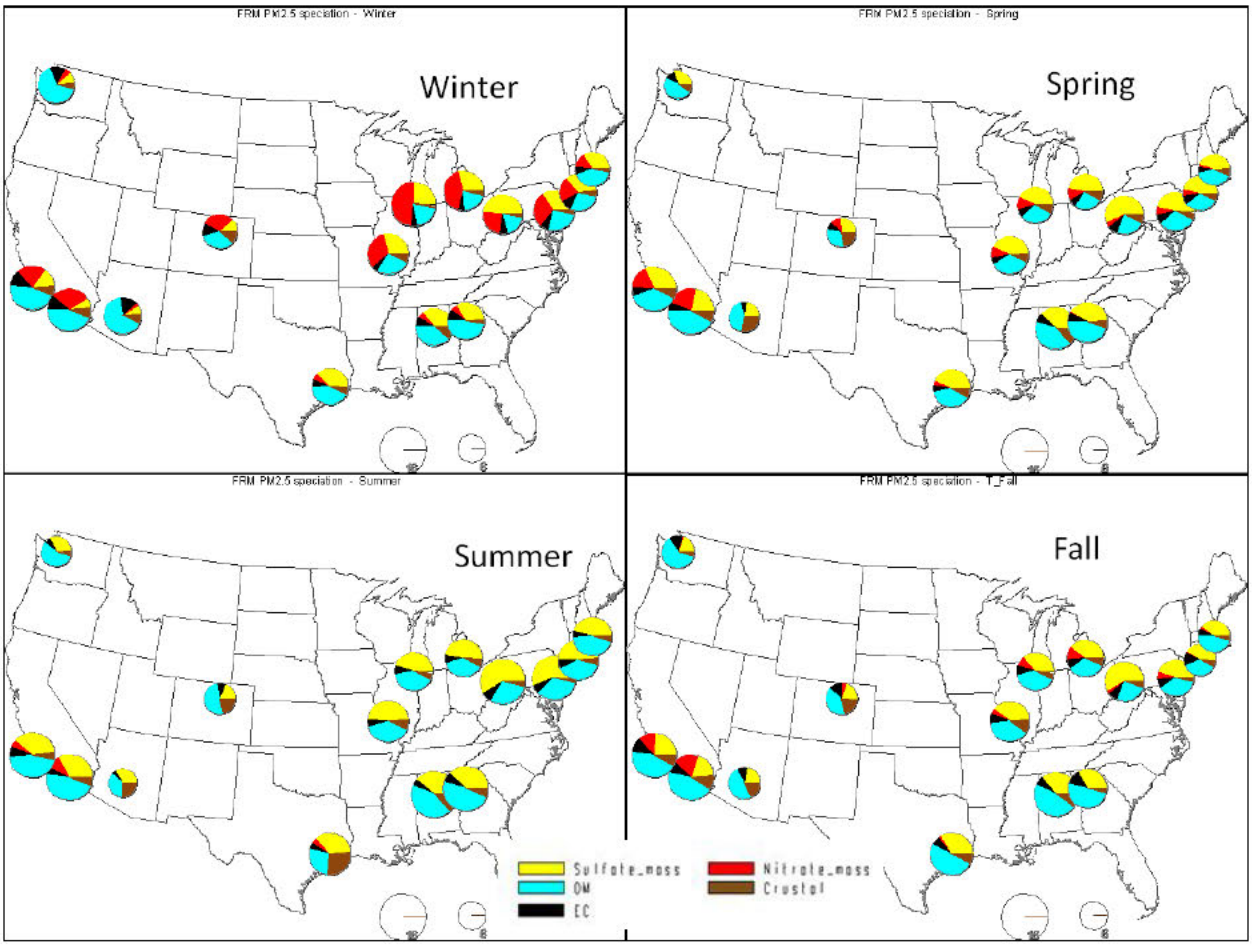
Fine particles often have a seasonal pattern. Both daily values and quarterly average of $PM_{2.5}$ also reveal patterns based on the time of year. Unlike daily ozone levels, which are usually elevated in the summer, daily $PM_{2.5}$ values at some locations can be high at any time of the year. As shown in Figure A-4, $PM_{2.5}$ values in the eastern half of the United States are typically higher in the third calendar quarter (July-September) when sulfates are more readily formed from sulfur dioxide (SO_2) emissions from power plants in that region and when secondary organic aerosol is more readily formed in the atmosphere. Fine particle concentrations tend to be higher in the first calendar quarter (January through March) in the Midwest in part because fine particle nitrates are more readily formed in cooler weather. $PM_{2.5}$ values are high during the first (January through March) and fourth calendar quarter (October through December) in many areas of the West, in part because of fine particle nitrates and also due to carbonaceous particles which are directly emitted from wood stove and fireplace use. Average concentration from all locations reporting $PM_{2.5}$ with valid design values is shown.

Figure A-4. Quarterly Averages of $PM_{2.5}$ Concentration: 2008-2010



The composition of $PM_{2.5}$ also varies by season and helps explain why mass varies by season. Figure A-5 shows the average composition by season (spring, summer, fall and winter) for $PM_{2.5}$ data collected during 2008-10. In the eastern United States, sulfate are high in the spring (March-May) and summer (July-September). Nitrates are most evident in the midwest and western cities where its percentage is moderately high in the spring and fall (October-and highest during the winter.) Organic mass (OM) is high throughout the year.

Figure A-5. Seasonal Speciation Profiles of $PM_{2.5}$ for Select Urban Areas: 2008-2010



The composition of the highest daily $PM_{2.5}$ values may be different than that for the annual average. Table A-1 provides 2008-10 data on daily $PM_{2.5}$ values and their composition on high mass days for various sites within large metropolitan areas (in the east: Birmingham, AL; Atlanta, GA; New York City, NY; Cleveland, OH; Chicago, IL; and St. Louis, MO; in the west: Salt Lake City, UT; and Fresno, CA). Mass is proportioned into five components: sulfates, nitrates, OM, elemental carbon (EC) and crustal material. For each site, the table shows the 2008-2010 annual average speciation profile, the breakdown for the top 10 percent of days per year and corresponding FRM mass. The table shows some notable differences in the percentage contribution of each of the species to total mass when looking at the high end of the distribution versus the annual average. Except for the southeast (where there is little nitrate in $PM_{2.5}$), nitrates are slightly higher in the top 10 percent of the $PM_{2.5}$ days. For the 2008-2010 measurements, the percent of sulfates is currently similar or slightly less on the top 10 percent of the days as compared to the annual averages. The portion of OM appears to be similar on the high days compared to the annual averages.

Table A-1. $PM_{2.5}$ Composition on High $PM_{2.5}$ Mass Days in Select Urban Areas: 2008-2010

Urban Area	Metric	Composition Percents (%)					PM2.5 Mass (ug/m3)	Ann. Avg	Top 10 %
		Sulfate	Nitrate	OM	EC	Crustal			
Atlanta	Ann Mean	35	1	46	9	5	12.2		
	Top 10%	35	1	49	8	5	22.3		
Birmingham	Ann Mean	37	1	42	7	9	14.1		
	Top 10%	34	1	47	8	9	27.4		
New York City	Ann Mean	44	9	26	12	5	11.3		
	Top 10%	41	13	30	10	4	24.2		
Cleveland	Ann Mean	40	13	27	7	9	13.4		
	Top 10%	42	15	26	7	7	28.5		
Chicago	Ann Mean	34	18	33	6	4	11.7		
	Top 10%	36	29	25	5	3	25.2		
St Louis	Ann Mean	40	13	29	7	7	12.3		
	Top 10%	37	20	30	6	4	24.2		
Salt Lake City	Ann Mean	13	27	36	7	12	10.2		
	Top 10%	8	55	25	5	6	35.3		
Fresno	Ann Mean	14	21	50	5	6	15.4		
	Top 10%	8	43	43	4	1	45.6		
San Diego	Ann Mean	26	4	54	7	5	12.4		
	Top 10%	16	14	58	7	2	23.2		
Tacoma	Ann Mean	17	2	62	9	4	9.4		
	Top 10%	8	3	74	10	3	25.1		



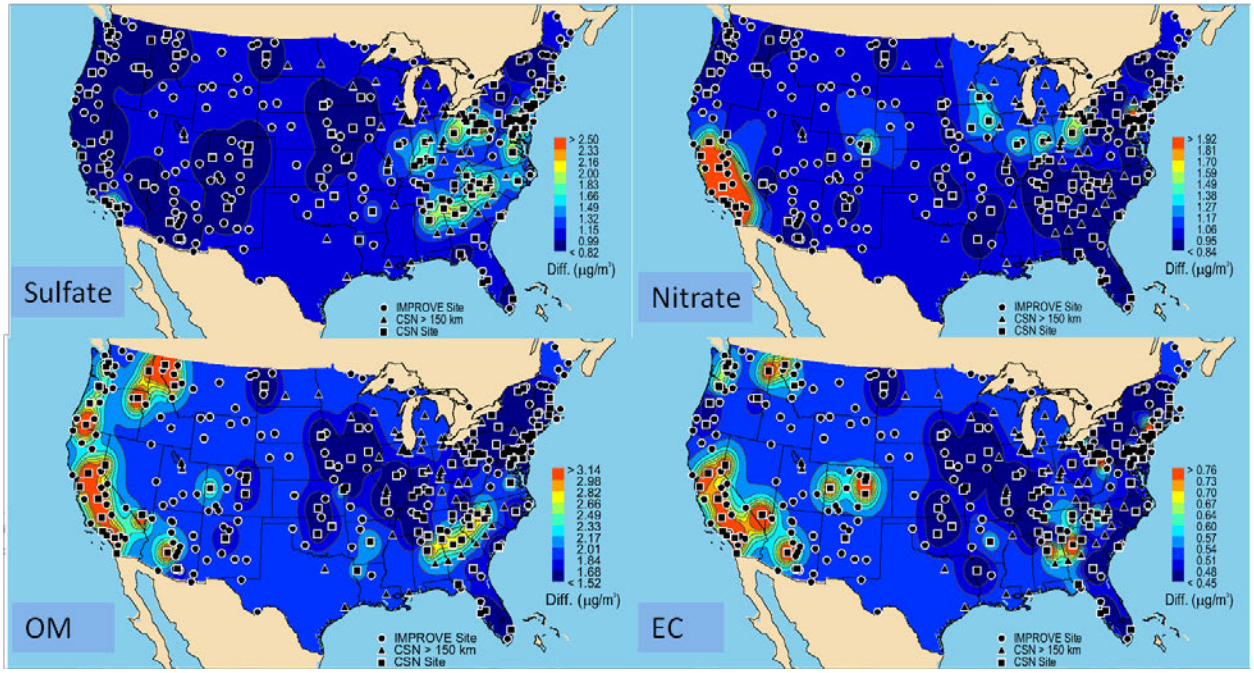
Note: The percentages do not add to 100% due to a small amount of passively collected fine particle mass included in the measurement of $PM_{2.5}$ by the FRM

4. Regional and Local Sources of $PM_{2.5}$

Both local and regional sources contribute to particle pollution. Figure A-6 shows how much of the $PM_{2.5}$ mass can be attributed to local versus regional sources for 13 selected urban areas. In each of these urban areas, monitoring sites were paired with nearby rural sites. When the average rural concentration is subtracted from the measured urban concentration, the estimated local and regional contributions become apparent. Urban and nearby rural $PM_{2.5}$ concentrations suggest substantial regional contributions to fine particles in the East. The measured $PM_{2.5}$ concentration is not necessarily the maximum for each urban area. Regional

concentrations are derived from the rural IMPROVE monitoring network.[43]

Figure A-6. "Urban excess" of locally generated $PM_{2.5}$ mass for four chemical components: sulfate, nitrate, organic mass (OM) and elemental carbon (EC)



Note: derived as the interpolated difference between urban CSN concentrations (squares) compared with nearby IMPROVE site concentrations within 150 km (circles). Annual mean concentrations from 2005-2008 are used. CSN sites not used in the analyses are shown as triangles.[44]

As shown in Figure A-6, we observe a large urban excess across the United State for most $PM_{2.5}$ species but especially for elemental carbon (EC) and organic mass (OM). Large excess for OM is observed in California, throughout the Northwest, and in the Southeast. The prevalence of urban excess in EC is seen more widely. Large urban excess of nitrates is seen in California. These results indicate that local sources of these pollutants are indeed contributing to the $PM_{2.5}$ air quality problem in these areas. As expected for a predominately regional pollutant, only a modest urban excess is observed for sulfates.

In the East, regional pollution contributes more than half of total $PM_{2.5}$ concentrations. Rural background $PM_{2.5}$ concentrations are high in the East and are somewhat uniform over large geographic areas. These regional concentrations come from emission sources such as power plants, natural sources, and urban pollution and can be transported hundreds of miles. The local and regional contributions for the major chemical components that make up urban $PM_{2.5}$: sulfates, carbon, and nitrates.

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[43] Information regarding the IMPROVE monitoring network can be found at the following website: http://vista.cira.colostate.edu/improve

[44] Hand et. al., Spatial and Seasonal Patterns and Temporal Variability of Haze and its Constituents in the United States: Report V, 2011 (http://vista.cira.colostate.edu/improve/Publications/Reports/2011/2011.htm)

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Appendix B: General Guidance on Use of Dispersion Models for Estimating Primary $PM_{2.5}$ Concentrations

This appendix provides general guidance on the application of dispersion models for estimating ambient concentrations of $PM_{2.5}$ associated with direct emissions of primary $PM_{2.5}$. This guidance is based on and is consistent with the EPA's *Guideline on Air Quality Models*, published as Appendix W of 40 CFR Part 51, and focuses primarily on the application of AERMOD, the EPA's preferred dispersion model for most situations. Appendix W is the primary source of information on the regulatory application of air quality models for State Implementation Plan (SIP) revisions for existing sources and for New Source Review (NSR) and Prevention of Significant Deterioration (PSD) programs. There will be applications of dispersion models unique to specific areas, (*i.e.*, there may be areas of the country where it is necessary to model unique specific sources or types of sources). In such cases, there should be consultation with the state or appropriate permitting authority with the appropriate EPA Regional Office modeling contact to discuss how best to model a particular source.

Recently issued EPA guidance of relevance for consideration in modeling for $PM_{2.5}$ includes:

- "Model Clearinghouse Review of Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS" February 26, 2010 (U.S. EPA, 2010a);
- "Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS" March 23, 2010 (U.S. EPA, 2010b); and
- "Transportation Conformity Guidance for Quantitative Hot-spot Analyses in $PM_{2.5}$ and PM_{10} Nonattainment and Maintenance Areas" November 2013 (U.S.EPA, 2013a).

The guidance listed above, in addition to other relevant support documents can be found on the SCRAM website at: http://www.epa.gov/ttn/scram/.

The following sections will refer to the relevant sections of Appendix W and other existing guidance with summaries as necessary. Please refer to those original guidance documents for full discussion and consult with the appropriate EPA Regional Office modeling contact if questions arise about interpretation on modeling techniques and procedures.[45]

1. Model selection

Preferred air quality models for use in regulatory applications are addressed in Appendix A of the EPA's *Guideline on Air Quality Models*. If a model is to be used for a particular application, the user should follow the guidance on the preferred model for that application. These models may be used without an area specific formal demonstration of applicability as long as they are used as indicated in each model summary of Appendix A. Further recommendations for the application of these models to specific source problems are found in Appendix W. In

[45] A list of EPA Regional Office modeling contacts is available on the SCRAM website at: http://www.epa.gov/ttn/scram/guidance_cont_regions htm.

2005, the EPA promulgated the American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) as the Agency's preferred near-field dispersion model for a wide range of regulatory applications in all types of terrain based on extensive developmental and performance evaluation. For PSD/NSR modeling under the $PM_{2.5}$ NAAQS, AERMOD should be used to model primary $PM_{2.5}$ emissions unless use of an alternative model can be justified (Section 3.2, Appendix W), such as the Buoyant Line and Point Source Dispersion Model (BLP).

The AERMOD modeling system includes the following components:

- AERMOD: the dispersion model (U.S. EPA, 2004a; U.S. EPA, 2014a);
- AERMAP: the terrain processor for AERMOD (U.S. EPA, 2004b, U.S. EPA, 2011a); and
- AERMET: the meteorological data processor for AERMOD (U.S. EPA, 2004c; U.S. EPA, 2014b).

Other components that may be used, depending on the application, are:

- BPIPPRIME: the building input processor (U.S. EPA, 2004d);
- AERSURFACE: the surface characteristics processor for AERMET (U.S. EPA, 2008);
- AERSCREEN: a screening version of AERMOD (U.S. EPA, 2011b; U.S. EPA, 2011c); and
- AERMINUTE: a pre-processor to calculate hourly average winds from ASOS 2-minute observations (U.S. EPA, 2011d).

Before running AERMOD, the user should become familiar with the user's guides associated with the modeling components listed above and the AERMOD Implementation Guide (AIG) (U.S. EPA, 2009). The AIG lists several recommendations for applications of AERMOD that would be applicable for SIP and PSD permit modeling.

1.2. Receptor grid

The model receptor grid is unique to the particular situation and depends on the size of the modeling domain, the number of modeled sources, and complexity of the terrain. Receptors should be placed in areas that are considered ambient air (i.e., where the public generally has access) and placed out to a distance such that areas of violation can be detected from the model output to help determine the size of nonattainment areas. Receptor placement should be of sufficient density to provide resolution needed to detect significant gradients in the concentrations with receptors placed closer together near the source to detect local gradients and placed farther apart away from the source. In addition, the user may want to place receptors at key locations such as around facility fence lines (which define the ambient air boundary for a particular source) or monitor locations (for comparison to monitored concentrations for model evaluation purposes). The receptor network should cover the modeling domain. States may already have existing receptor placement strategies in place for regulatory dispersion modeling under NSR/PSD permit programs.

If modeling indicates elevated levels of $PM_{2.5}$ (near the standard) near the edge of the receptor grid, consideration should be given to expanding the grid or conducting an additional modeling run centered on the area of concern. As noted above, terrain complexity should also be considered when setting up the receptor grid. If complex terrain is included in the model calculations, AERMOD requires that receptor elevations be included in the model inputs. In those cases, the AERMAP terrain processor (U.S. EPA, 2004b; U.S EPA, 2011a) should be used to generate the receptor elevations and hill heights. The latest version of AERMAP (version 09040 or later) can process either Digitized Elevation Model (DEM) or National Elevation Data (NED) data files. The AIG recommends the use of NED data since it is more up to date than DEM data, which is no longer updated (Section 4.3 of the AIG).

2. Source inputs

This section provides guidance on source characterization to develop appropriate inputs for dispersion modeling with the AERMOD modeling system. Section 2.1 provides guidance on use of emission, Section 2.2 covers guidance on Good Engineering Practice (GEP) stack heights, Section 2.3 provides details on source configuration and source types, Section 2.4 provides details on urban/rural determination of the sources, and Section 2.5 provides general guidance on source grouping, which may be important for design value calculations.

2.1. Emissions

Consistent with Appendix W, dispersion modeling for the purposes of PSD permitting should be based on the use of continuous operation at maximum allowable emissions or federally enforceable permit limits (see Table 8-2 of Appendix W) for the project source for all applicable averaging periods. Also consistent with past and current guidance, in the absence of maximum allowable emissions or federally enforceable permit limits, potential to emit emissions (i.e., design capacity) should be used. Maximum allowable emissions and continuous operation should also be assumed for nearby sources included in the modeled inventory for the 24-hr $PM_{2.5}$ NAAQS, while maximum allowable emissions and the actual operating factor averaged over the most recent 2 years should be used for modeled nearby sources for the annual $PM_{2.5}$ NAAQS.

2.2. Good Engineering Practice (GEP) stack height

Consistent with previous modeling guidance and Section 6.2.2 of Appendix W, for stacks with heights that are within the limits of Good Engineering Practice (GEP), actual heights should be used in modeling. Under the EPA's regulations at 40 CFR 51.100, GEP height, H_g, is determined to be the greater of:

- 65 m, measured from the ground-level elevation at the base of the stack;
- for stacks in existence on January 12, 1979, and for which the owner or operator had obtained all applicable permits or approvals required under 40 CFR Parts 51 and 52

$$H_g=2.5H$$

provided the owner or operator produces evidence that this equation was actually relied

on in designing the stack or establishing an emission limitation to ensure protection against downwash;

- for all other stacks,

$$H_g = H + 1.5L,$$

where H is the height of the nearby structure(s) measured from the ground-level elevation at the base of the stack and L is the lesser dimension of height or projected width of nearby structure(s); or

- the height demonstrated by a fluid model or a field study approved by the EPA or the state/local permitting agency which ensures that the emissions from a stack do not result in excessive concentrations of any air pollutant as a result of atmospheric downwash, wakes, eddy effects created by the source itself, nearby structures or nearby terrain features.

For more details about GEP, see the Guideline for Determination of Good Engineering Practice Stack Height Technical Support Document (U.S. EPA, 1985).

If stack heights exceed GEP, then GEP heights should be used with the individual stack's other parameters (temperature, diameter, exit velocity). For stacks modeled with actual heights below GEP that may be subject to building downwash influences, building downwash should be considered as this can impact concentrations near the source (Section 6.2.2b, Appendix W). If building downwash is being considered, the BPIPPRIME program (U.S. EPA, 2004d) should be used to input building parameters for AERMOD. More information about buildings and stacks is provided in Section 6.5.

2.3. Source configurations and source types

An accurate characterization of the modeled facilities is critical for refined dispersion modeling, including accurate stack parameters and physical plant layout. Accurate stack parameters should be determined for the emissions being modeled. Since modeling would be done with maximum allowable or potential emissions levels at each stack, the stack's parameters such as exit temperature, diameter, and exit velocity should reflect those emissions levels. Accurate locations (i.e.. latitude and longitude or Universal Transverse Mercator (UTM) coordinates and datum)[46] of the modeled emission sources are also important, as this can affect the impact of an emission source on receptors, determination of stack base elevation, and relative location to any nearby building structures. Not only are accurate stack locations needed, but accurate information for any nearby buildings is important. This information would include location and orientation relative to stacks and building size parameters (height, and corner coordinates of tiers) as these parameters are input into BPIPPRIME to calculate building parameters for AERMOD. If stack locations and or building information are not accurate,

[46] Latitudes and longitudes to four decimal places position a stack within 30 feet of its actual location and five decimal places position a stack within three feet of its actual location. Users should use the greatest precision available.

downwash will not be accurately accounted for in AERMOD.

Emission source type characterization within the modeling environment is also important. As stated in the AERMOD User's Guide (U.S. EPA, 2004a; U.S. EPA, 2012a), emissions sources can be characterized as several different source types: POINT sources, capped stacks (POINTCAP), horizontal stacks (POINTHOR), VOLUME sources, OPENPIT sources, LINE sources, rectangular AREA sources, circular area sources (AREACIRC), and irregularly shaped area sources (AREAPOLY). Note that POINTCAP and POINTHOR are not part of the regulatory default option in AERMOD because the user must invoke the BETA option in the model options keyword MODELOPT while not including the "DFAULT" modeling option for these options to work properly. While most sources can be characterized as POINT sources, some sources, such as fugitive releases or nonpoint sources (emissions from ports/ships, airports, or smaller point sources with no accurate locations), may be best characterized as VOLUME or AREA type sources. Sources such as flares can be modeled in AERMOD using the parameter input methodology described in Section 2.1.2 of the AERSCREEN User's Guide (U. S. EPA, 2011b). If questions arise about proper source characterization or typing, users should consult the appropriate EPA Regional Office modeling contact.

2.4. Urban/rural determination

For any dispersion modeling exercise, the urban or rural determination of a source is important in determining the boundary layer characteristics that affect the model's prediction of downwind concentrations. Figure B-1 gives example maximum 24-hour concentration profiles for a 10 meter stack (Figure B-1a) and a 100 m stack (Figure B-1b) based on urban vs. rural designation. The urban population used for the examples is 100,000. In Figure B-1a, the urban concentration is much higher than the rural concentration for distances less than 750 m from the stack but then drops below the rural concentration beyond 750 m. For the taller stack in Figure B-1b, the urban concentration is much higher than the rural concentration even as distances increase from the source. These profiles show that the urban or rural designation of a source can be quite important.

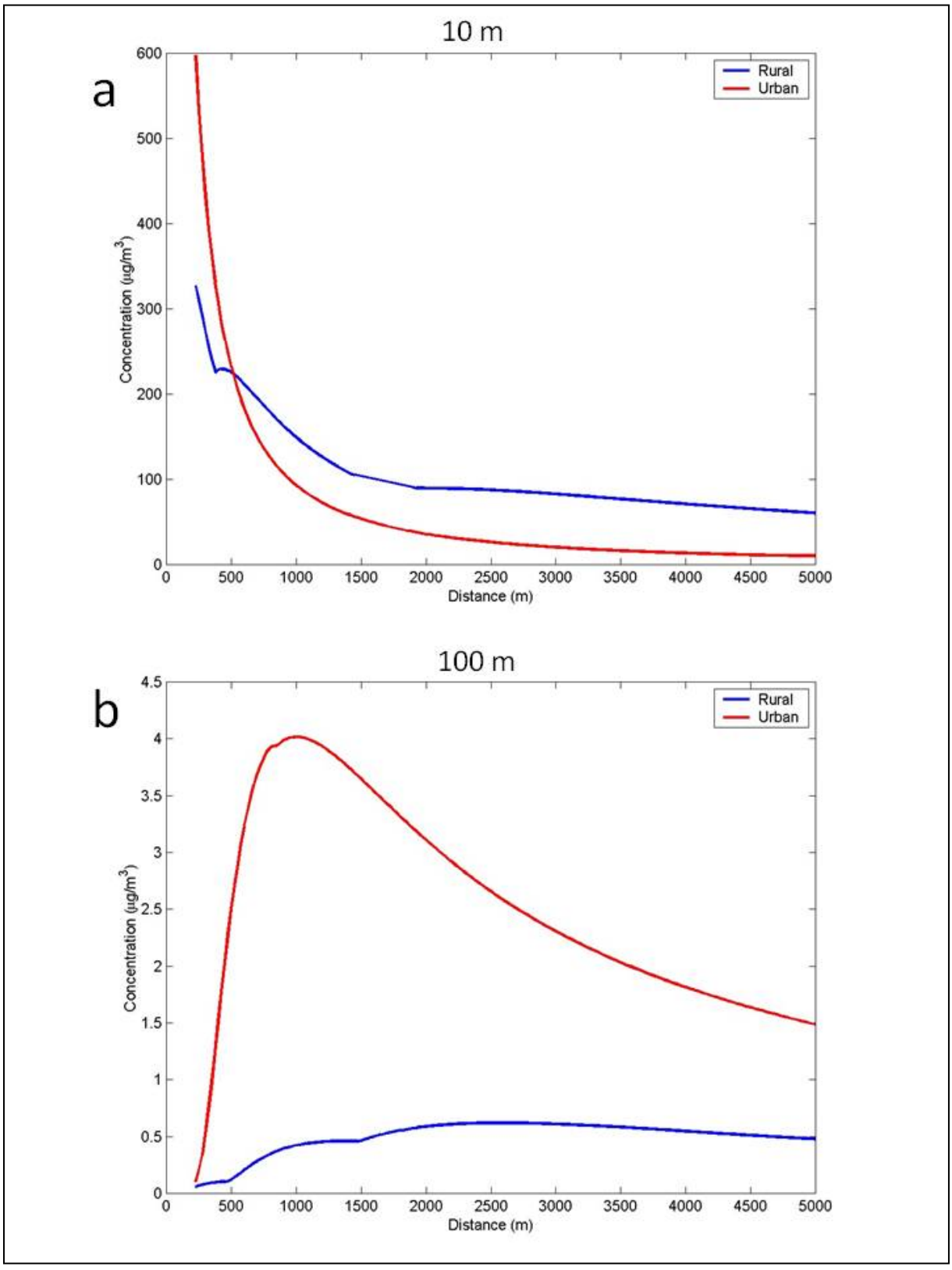
Determining whether a source is urban or rural can be done using the methodology outlined in Section 7.2.3 of Appendix W and recommendations outlined in Sections 5.1 through 5.3 in the AIG (U.S. EPA, 2009). In summary, there are two methods of urban/rural classification described in Section 7.2.3 of Appendix W.

The first method of urban determination is a land use method (Appendix W, Section 7.2.3c). In the land use method, the user analyzes the land use within a 3 km radius of the source using the meteorological land use scheme described by Auer (1978). Using this methodology, a source is considered urban if the land use types I1 (heavy industrial), I2 (light-moderate industrial), C1 (commercial), R2 (common residential), and R3 (compact residential) are 50 percent or more of the area within the 3 km radius circle. Otherwise, the source is considered a rural source. The second method uses population density and is described in Section 7.2.3d of Appendix W. As with the land use method, a circle of 3 km radius is used. If the population density within the circle is greater than 750 people/km^2, then the source is considered urban. Otherwise, the source is modeled as a rural source. Of the two methods, the land use method is

considered more definitive (Section 7.2.3e, Appendix W).

Caution should be exercised with either classification method. As stated in Section 5.1 of the AIG (U.S. EPA, 2009), when using the land use method, a source may be in an urban area but located close enough to a body of water or other non-urban land use category to result in an erroneous rural classification for the source. The AIG in Section 5.1 cautions users against using the land use scheme on a source by source basis, but advises considering the potential for urban heat island influences across the full modeling domain. When using the population density method, Section 7.2.3e of Appendix W states, "Population density should be used with caution and should not be applied to highly industrialized areas where the population density may be low and thus a rural classification would be indicated, but the area is sufficiently built-up so that the urban land use criteria would be satisfied..." With either method, Section 7.2.3(f) of Appendix W recommends modeling all sources within an urban complex as urban, even if some sources within the complex would be considered rural using either the land use or population density method.

Figure B-1. Urban (red) and rural (blue) concentration profiles for (a) 10 m buoyant stack release, and (b) 100 m buoyant stack release



Another consideration that may need attention by the user, and is discussed in Section 5.1 of the AIG, relates to tall stacks located within or adjacent to small to moderate size urban areas. In such cases, the stack height or effective plume height for very buoyant sources may extend above the urban boundary layer height. The application of the urban option in AERMOD for these types of sources may artificially limit the plume height. The use of the urban option may not be appropriate for these sources, since the actual plume is likely to be transported over the urban boundary layer. Section 5.1 of the AIG gives details on determining if a tall stack should be modeled as urban or rural based on comparing the stack or effective plume height to the urban boundary layer height. The 100 m stack illustrated in Figure B-1b, may be such an example as the urban boundary layer height for this stack would be 189 m (based on a population of 100,000) and equation 104 of the AERMOD formulation document (Cimorelli, et al., 2004). This equation is:

$$z_{iuc} = z_{iuo}\left(\frac{P}{P_o}\right)^{1/4} \quad \text{(B-1)}$$

where z_{iuo} is a reference height of 400 m corresponding to a reference population P_o of 2,000,000 people.

Given that the stack is a buoyant release, the plume may extend above the urban boundary layer and may be best characterized as a rural source, even if it were near an urban complex. Exclusion of these elevated sources from application of the urban option would need to be justified on a case-by-case basis in consultation with the appropriate permitting authority.

AERMOD requires the input of urban population when utilizing the urban option. Population can be entered to one or two significant digits (i.e., an urban population of 1,674,365 can be entered as 1,700,000). Users can enter multiple urban areas and populations using the URBANOPT keyword in the runstream file (U.S. EPA, 2004a; U.S. EPA, 2012a). If multiple urban areas are entered, AERMOD requires that each urban source be associated with a particular urban area or AERMOD model calculations will abort. Urban populations can be determined by using a method described in Section 5.2 of the AIG (U.S. EPA, 2009).

2.5. Source groups

In AERMOD, individual emission sources' concentration results can be combined into groups using the SRCGROUP keyword (Section 3.3.11 of the AERMOD User's Guide (U.S, EPA, 2004a). The user can automatically calculate a total concentration (from all sources) using the SRCGROUP ALL keyword. For the purposes of design value calculations, source group ALL should be used, especially if all sources in the modeling domain are modeled in one AERMOD run. Design values should be calculated from the total concentrations (all sources and background). Individual source contributions outputs to the total concentration may be necessary to determine the culpability to any NAAQS violations.

3. Meteorological data

This section gives guidance on the selection of meteorological data for input into AERMOD. Much of the guidance from Section 8.3 of Appendix W is applicable to SIP and PSD permit modeling and is summarized here. In Section 7.2.1, the use of a new tool, AERMINUTE (U.S. EPA, 2011d), is introduced. AERMINUTE is an AERMET pre-processor that calculates hourly averaged winds from ASOS (Automated Surface Observing System) 1-minute winds.

3.1. Surface characteristics and representativeness

The selection of meteorological data that are input into a dispersion model should be considered carefully. The selection of data should be based on spatial and climatological (temporal) representativeness (Appendix W, Section 8.3). The representativeness of the data is based on: 1) the proximity of the meteorological monitoring site to the area under consideration, 2) the complexity of terrain, 3) the exposure of the meteorological site, and 4) the period of time during which data are collected. Sources of meteorological data are: National Weather Service (NWS) stations, site-specific or onsite data, and other sources such as universities, Federal Aviation Administration (FAA), military stations, and others. Appendix W addresses spatial representativeness issues in Sections 8.3.a and 8.3.c.

Spatial representativeness of the meteorological data can be adversely affected by large distances between the source and receptors of interest and the complex topographic characteristics of the area (Appendix W, Section 8.3.a and 8.3.c). If the modeling domain is large enough such that conditions vary drastically across the domain, then the selection of a single station to represent the domain should be carefully considered. Also, care should be taken when selecting a station if the area has complex terrain. While a source and meteorological station may be in close proximity, there may be complex terrain between them such that conditions at the meteorological station may not be representative of the source. An example would be a source located on the windward side of a mountain chain with a meteorological station a few kilometers away on the leeward side of the mountain. Spatial representativeness for off-site data should also be assessed by comparing the surface characteristics (albedo, Bowen ratio, and surface roughness) of the meteorological monitoring site and the analysis area. When processing meteorological data in AERMET (U.S. EPA, 2004c; U.S. EPA, 2014b), the surface characteristics of the meteorological site should be used (Section 8.3.c of Appendix W and the AERSURFACE User's Guide (U.S. EPA 2008)). Spatial representativeness should also be addressed for each meteorological variable separately. For example, temperature data from a meteorological station several kilometers from the analysis area may be considered adequately representative, while it may be necessary to collect wind data near the plume height (Section 8.3.c of Appendix W).

Surface characteristics can be calculated in several ways. For details see Section 3.1.2 of the AIG (U.S. EPA, 2009). The EPA has developed a tool, AERSURFACE (U.S. EPA, 2008) to aid in the determination of surface characteristics. The current version of AERSURFACE uses the 1992 National Land Cover Data. Note that the use of AERSURFACE is not a regulatory requirement but the methodology outlined in Section 3.1.2 of the AIG should be followed unless an alternative method can be justified.

3.2. Meteorological inputs

Appendix W states in Section 8.3.1.1 that the user should acquire enough meteorological data to ensure that worst-case conditions are adequately represented in the model results. Appendix W states that 5 years of NWS meteorological data or at least 1 year of site-specific data should be used(Section 8.3.1.2, Appendix W) and should be adequately representative of the study area. If 1 or more years of site-specific data are available, those data are preferred. While the form of the $PM_{2.5}$ NAAQS contemplates obtaining 3 years of monitoring data, this does not preempt the use of 5 years of NWS data or at least 1 year of site-specific data in the modeling. The 5-year average based on the use of NWS data, or an average across 1 or more years of available site specific data, serves as an unbiased estimate of the 3-year average for purposes of modeling demonstrations of compliance with the NAAQS.

3.2.1. NWS data

NWS data are available from the National Climatic Data Center (NCDC) in many formats, with the most common one in recent years being the Integrated Surface Hourly data (ISH). Most available formats can be processed by AERMET. As stated in Section 3.1, when using data from an NWS station alone or in conjunction with site-specific data, the data should be spatially and temporally representative of conditions at the modeled sources. Key points regarding the use of NWS data can be found in the EPA's March 8, 2013 clarification memo "Use of ASOS meteorological data in AERMOD dispersion modeling" (U.S. EPA, 2013b). The key points are:

- The EPA has previously analyzed the effects of ASOS implementation on dispersion modeling and found that generally AERMOD was less sensitive than ISCST3 to the implementation of ASOS.
- The implementation of the ASOS system over the conventional observation system should not preclude the consideration of NWS stations in dispersion modeling.
- The EPA has implemented an adjustment factor (0.5 knots) in AERMET to adjust for wind speed truncation in ASOS winds
  The EPA has developed the AERMINUTE processor (U.S. EPA, 2011d) to process 2-minute ASOS winds and calculate an hourly average for input into AERMET. The use of hourly averaged winds better reflect actual conditions over the hour as opposed to a single 2-minute observation.

While the EPA's March 8, 2013, memo states that ASOS should not preclude the use of NWS data in dispersion modeling, and Section 8.3.1.2 of Appendix W recommends the most recent five years of NWS data, Section 8.3.1.2 also recognizes cases where professional judgment indicates that ASOS data are inadequate and pre-ASOS, or observer based data may be considered for use. The appropriate permitting authority and EPA Regional Office modeling contact should be consulted when questions arise about the representativeness or applicability of NWS data.

3.2.2. Site-specific data

The use of site-specific meteorological data is the best way to achieve spatial representativeness. AERMET can process a variety of formats and variables for site-specific data. The use of site-specific data for regulatory applications is discussed in detail in Section 8.3.3 of Appendix W. Due to the range of data that can be collected onsite and the range of formats of data input to AERMET, the user should consult Appendix W, the AERMET User's Guide (U.S. EPA, 2004c; U. S. EPA, 2014b), and Meteorological Monitoring Guidance for Regulatory Modeling Applications (U.S. EPA, 2000). Also, when processing site-specific data for an urban application, Section 3.3 of the AERMOD Implementation Guide offers recommendations for data processing. In summary, the guide recommends that site-specific turbulence measurements should not be used when applying AERMOD's urban option in order to avoid double counting the effects of enhanced turbulence due to the urban heat island.

3.2.3. Upper air data

AERMET requires full upper air soundings to calculate the convective mixing height. For AERMOD applications in the U.S., the early morning sounding, usually the 1200 UTC (Universal Time Coordinate) sounding, is typically used for this purpose. Upper air soundings can be obtained from the Radiosonde Data of North America CD for the period 1946-1997. Upper air soundings for 1994 through the present are also available for free download from the Radiosonde Database Access website. Users should choose all levels or mandatory and significant pressure levels[47] when selecting upper air data. Selecting mandatory levels only would not be adequate for input into AERMET as the use of just mandatory levels would not provide an adequate characterization of the potential temperature profile.

4. Running AERMOD and implications for design value calculations

Recent enhancements to AERMOD include options to aid in the calculation of design values for comparison with the $PM_{2.5}$ NAAQS and to aid in determining whether emissions from the project source contributed significantly to any modeled violations. These enhancements include:

- The MAXDCONT option, which shows the contribution of each user-specified source group to the high ranked values for a specified target source group paired in time and space. The user can specify a range of ranks to analyze or specify an upper bound rank, i.e. 8^{th} highest, corresponding to the 98^{th} percentile for the 24-hour $PM_{2.5}$ NAAQS, and a lower threshold concentration value, such as the NAAQS for the target source group. The model will process each rank within the range specified, but will stop after the first rank (in descending order of concentration) that is below the threshold value if specified by the user. A warning message will be generated if the threshold is not reached within the range of ranks analyzed (based on the range of ranks specified on the RECTABLE keyword). This option may be needed to aid in determining which sources should be considered for controls.

[47] By international convention, mandatory levels are in millibars: 1,000, 850, 700, 500, 400, 300, 200, 150, 100, 50, 30, 20, 10, 7 5, 3, 2, and 1. Significant levels may vary depending on the meteorological conditions at the upper-air station.

For more details about the enhancements, see the AERMOD User's guide Addendum (U. S. EPA, 2014a).

Ideally, all explicitly modeled sources, receptors, and background should be modeled in one AERMOD run for all modeled years. In this case, one of the above output options can be used in AERMOD to calculate design values for comparison to the NAAQS and determine the area's attainment status and/or inform attainment/nonattainment boundaries. The use of these options in AERMOD allows AERMOD to internally calculate concentration metrics that can be used to calculate design values and, therefore, lessen the need for large output files, i.e. hourly POSTFILES.

However, there may be situations where a single AERMOD run with all explicitly modeled sources is not possible. These situations often arise due to runtime or storage space considerations during the AERMOD modeling. Sometimes separate AERMOD runs are done for each facility or group of facilities, or by year, or the receptor network is divided into separate sub-networks. In some types of these situations, the MAXDCONT output option may not be an option for design value calculations, especially if all sources are not included in a single run. If the user wishes to utilize one of the three output options, then care should be taken in developing the model inputs to ensure accurate design value calculations.

Situations that would effectively preclude the use of the MAXDCONT option to calculate meaningful AERMOD design value calculations include the following examples:

- Separate AERMOD runs for each source or groups of sources.
    - SIP modeling includes 10 facilities for 5 years of NWS data and each facility is modeled for 5 years in a separate AERMOD run, resulting in ten separate AERMOD runs.
- Separate AERMOD runs for each source and each modeled year.
    - 10 facilities are modeled for 5 years of NWS data. Each facility is modeled separately for each year, resulting in fifty individual AERMOD runs.

In the two situations listed above, the MAXDCONT option would not be useful as the different AERMOD runs do not include a total concentration with contributions from all facilities. In these situations, the use of 24-hour POSTFILES, which can be quite large, and external post-processing would be needed to calculate design values.

Situations in which the MAXDCONT options may be used but may necessitate some external post-processing afterwards to calculate a design value include:

- The receptor network is divided into sections and an AERMOD run, with all sources and years, is made for each sub-network.
    - A receptor network of 1,000 receptors is divided into four 250 receptor sub-networks. 10 facilities are modeled with 5 years of NWS data in one AERMOD run for each receptor network, resulting in four AERMOD runs. After the

AERMOD runs are complete, the MAXDCONT results for each network can be re-combined into the larger network.

- All sources and receptors are modeled in an AERMOD run for each year.
- Ten facilities are modeled with 5 years of NWS data. All facilities are modeled with all receptors for each year individually, resulting in five AERMOD runs. MAXDCONT output can be used and post-processed to generate the necessary design value concentrations. The receptor network is divided and each year is modeled separately for each sub-network with all sources.
- Ten facilities are modeled with 5 years of NWS data for 1,000 receptors. The receptor network is divided into four 250 receptor networks. For each sub-network, all ten facilities are modeled for each year separately, resulting in twenty AERMOD runs. MAXDCONT output can be used and post-processed to generate the necessary design value concentrations.

5. References

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Appendix C: Example of a Qualitative Assessment of the Potential for Secondary $PM_{2.5}$ Formation

In late 2011, the EPA Region 10 Office developed a qualitative assessment of the potential for secondary fine particulate matter ($PM_{2.5}$) formation to cause or contribute to a violation of the $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS) through a response to public comments document regarding a Clean Air Act permit issued for Shell's *Discoverer* drill ship and support fleet to explore for oil and gas in the Chukchi Sea off Alaska. While the environment in and around the Chukchi Sea and North Slope of Alaska is unique when compared to the rest of the United States, the various components contained within this qualitative assessment provide a template that could be followed, with appropriate modifications, in the development of other case-specific qualitative assessments. An excerpt from this response to public comments document is provided below for reference.

As shown in the EPA Region 10 example, the qualitative assessment of the potential for secondary $PM_{2.5}$ formation by the Shell's *Discoverer* drill ship and support fleet was developed in a narrative manner integrating numerous factors specific to the North Slope region of Alaska that provided sufficient evidence that the $PM_{2.5}$ NAAQS would not be violated in this particular case. The qualitative assessment examined the regional background $PM_{2.5}$ monitoring data and aspects of secondary $PM_{2.5}$ formation from existing sources; the relative ratio of the combined modeled primary $PM_{2.5}$ impacts and background $PM_{2\ 5}$ concentrations to the level of the NAAQS; the spatial and temporal correlation of the primary and secondary $PM_{2.5}$ impacts; meteorological characteristics of the region during periods of precursor pollutant emissions; the level of conservatism associated with the modeling of the primary $PM_{2.5}$ component and other elements of conservatism built into the overall NAAQS compliance demonstration; aspects of the precursor pollutant emissions in the context of limitations of other chemical species necessary for the photochemical reactions to form secondary $PM_{2.5}$; and an additional level of NAAQS protection through a post-construction monitoring requirement. While each of the components of the EPA Region 10 example may or may not be necessary, this example should provide a useful template for other qualitative assessments under this guidance, recognizing that additional components may be essential in other qualitative assessments of the potential for secondary $PM_{2.5}$ formation.

Additional information regarding this EPA Region 10 Office permit action can be found through the following web link: http://yosemite.epa.gov/R10/airpage.nsf/Permits/chukchiap/.

Region 10 example:

> In support of the 2011 Revised Draft Permits, Region 10 provided a detailed explanation for why it believes that modeling secondary $PM_{2.5}$ emissions is not needed in order to determine that emissions of $PM_{2.5}$ precursors from the *Discoverer* and Associated Fleet would not, together with emissions of primary $PM_{2.5}$, cause or contribute to a violation of the 24-hour $PM_{2.5}$ NAAQS. The factors Region 10 relied on to reach this conclusion include:

1) The background $PM_{2.5}$ monitoring data considered in the air quality analysis is quality assured, quality controlled data from monitors operating for more than one year that Region 10 believes will have accounted for much of the secondary formation from existing regional emission sources that will occur in the Chukchi Sea and Beaufort Sea regions. Monitoring data show low levels of daily $PM_{2.5}$, generally in the range of 2 $\mu g/m^3$, with the higher $PM_{2.5}$ values generally occurring on days where windblown dust or fires are believed to be contributing factors. Thus, there is no indication that secondary formation of $PM_{2.5}$ from existing sources in the North Slope is currently causing or contributing to exceedances or a violation of the $PM_{2.5}$ NAAQS in the onshore communities.

2) Modeled primary $PM_{2.5}$ impacts from the *Discoverer* and Associated Fleet that, when using a conservative "First Tier" approach to combining modeled primary $PM_{2.5}$ impacts with monitored background $PM_{2.5}$ concentrations, are less than 67 percent of the $PM_{2.5}$ NAAQS. Thus, although not expected, considerable formation of secondary $PM_{2.5}$ emissions could occur before the NAAQS would be threatened.

3) Secondary $PM_{2.5}$ impacts associated with *Discoverer* and Associated Fleet precursor emissions are expected to be low near the emission release points where modeled concentrations associated with primary $PM_{2.5}$ emissions are highest, because there has not been enough time for the secondary chemical reactions to occur. Conversely, secondary $PM_{2.5}$ impacts are more likely to be higher farther from the *Discoverer* and the Associated Fleet where impacts from primary $PM_{2.5}$ emissions from the *Discoverer* and the Associated Fleet are expected to be lower. This makes it unlikely that maximum primary $PM_{2.5}$ impacts and maximum secondary $PM_{2.5}$ impacts from the *Discoverer* and the Associated Fleet will occur at the same time (paired in time) or location (paired in space). See March 23, 2010 $PM_{2.5}$ Guidance Memo at 9.

4) The relatively small amount of NO_X emissions (a $PM_{2.5}$ precursor) that will be authorized under these permits in comparison to existing NO_X emissions in the North Slope area in general, together with the generally low levels of $PM_{2.5}$ recorded at monitoring stations in the area, make it unlikely that NO_X emissions from the *Discoverer* and the Associated Fleet would cause or contribute to a violation of the $PM_{2.5}$ NAAQS.

5) The background concentrations of certain chemical species that participate in photochemical reactions to form secondary $PM_{2.5}$, including ammonia and volatile organic compounds, are expected to be negligible in the offshore air masses where the *Discoverer* will be permitted to operate. The emissions authorized under the permits of approximately 43 tons per year of VOC and 0.52 tons per year of ammonia [citation omitted] would also not be expected to result in the conversion of significant quantities of NO_X emissions to secondary particles in the areas impacted by primary $PM_{2.5}$ emissions.

6) There are several other conservative assumptions incorporated in the modeling of primary $PM_{2.5}$ emissions. These include the conservatism inherent in using a "First Tier" approach to combining modeled primary $PM_{2.5}$ impacts with monitored background $PM_{2.5}$ concentrations; assuming that the *Discoverer* will be operating in a single drilling location for 3 years, when it is more likely that the *Discoverer* will operate in a different location each year (if not more frequently); orienting the Associated Fleet with hourly modeled wind direction and using emission release characteristics based on actual meteorological conditions; and the fact that the background monitored data used to represent offshore conditions was collected onshore, where it is influenced by local sources, and is, therefore likely to be a conservative estimate of background $PM_{2.5}$ levels in the area of maximum impact near the *Discoverer*.

7) With respect to the Chukchi Sea impacts, the predominant easterly wind directions in the Chukchi Sea along with the distance between the project location and the existing sources in the North Slope oil and gas fields are such that emissions from the *Discoverer* and Associated Fleet are not likely to significantly contribute to the maximum ambient concentrations resulting from the existing source emissions.

8) Region 10 required post-construction monitoring in the previous permits because the conservative screening modeling resulted in predicted levels that were just below the 24-hour $PM_{2.5}$ NAAQS. With the additional emission reductions in direct $PM_{2.5}$ emissions and the use of a refined model, predicted $PM_{2.5}$ concentrations are now well below the NAAQS. However, Region 10 has decided to retain the post-construction monitoring requirement in order to obtain better information on the quantity of secondary particles in the North Slope communities.

Based on these factors, and consistent with current guidance, Region 10 believes that an adequate assessment has been made to demonstrate that the $PM_{2.5}$ NAAQS will be protected, accounting for primary $PM_{2.5}$ impacts and potential contributions due to $PM_{2.5}$ precursors from the *Discoverer* and the Associated Fleet, and that it is not necessary to use a photochemical model to further evaluate secondary $PM_{2.5}$ formation in these permitting actions.

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Appendix D: Example of a Hybrid Qualitative/Quantitative Assessment of the Potential for Secondary $PM_{2.5}$ Formation

In late 2013/early 2014, a permit applicant, Sasol, engaged and closely coordinated with the EPA Region 6 Office and the Louisiana Department of Environmental Quality (LDEQ) in the development of a hybrid qualitative/quantitative assessment of the potential for secondary fine particulate matter ($PM_{2.5}$) formation to cause or contribute to a violation of the $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS) for their proposed major facility expansions in Southern Louisiana. Sasol's expansion and new plant are a very large investment (up to $18 Billion), and Sasol and LDEQ worked closely with Region 6 to ensure that the ambient impacts analysis was robust and defendable. In this particular hybrid assessment, Sasol took an approach of using the formerly presumptive interpollutant trading ratios for NO_x and SO_2 to $PM_{2.5}$ offsets and conservatively applied them in an illustrative example to demonstrate how relatively inconsequential the impacts of secondary $PM_{2.5}$ formation would be in the area of significant impact surrounding their facility. In Sasol's case, the projected emissions increases of the direct $PM_{2.5}$ emissions and both $PM_{2.5}$ precursors of NO_x and SO_2 were above their respective Significant Emissions Rates (SERs). Sasol also performed an analysis of $PM_{2.5}$ speciated monitoring data to further support the amount of impacts of nitrates on high $PM_{2\,5}$ values in the area is relatively small and corroborate the ratio based analysis. Thus, this situation is an example of a Case 3 assessment as presented in Table III-1 of this guidance.

It is important to note that the EPA revised the provisions of the interpollutant trading policy for $PM_{2.5}$ on July 21, 2011, as described in Section III.2.2 of this guidance, to remove the general presumptiveness of the interpollutant trading ratios without further technical justification. Sasol is located in Southwestern Louisiana near the coast but chose to use the western state value of 100 for NOx as a more conservative assessment. Sasol did not seek to directly apply the formerly presumptive interpollutant trading ratios in an absolute sense. Rather, the intention was to present the analysis in a manner to determine if further technical justification would be required or if the application of the formerly presumptive interpollutant trading ratios where adequate in a hybrid qualitative/quantitative sense.

Using the formerly presumptive interpollutant trading ratios resulted in total projected secondary $PM_{2.5}$ formation of 0.18 $\mu g/m^3$ for the 24-hour $PM_{2.5}$NAAQS and of 0.04 $\mu g/m^3$ for the annual $PM_{2.5}$ NAAQS. When considered along with the primary $PM_{2.5}$ impacts and representative background data, the secondary $PM_{2.5}$ impacts with respect to the 24-hour NAAQS would have to be on the order of 32 times higher and to the annual NAAQS would have to be at least 15 times greater before a potential projected violation might occur. This also assumes that the maximum secondary $PM_{2.5}$ impacts from the NO_x and SO_2 precursor emissions would occur at the same place and time as the maximum primary $PM_{2.5}$ impacts. Based upon Sasol's $PM_{2.5}$ primary modeling projecting maximum concentrations very close to the facility and decreasing 60% within three kilometers of the facility, it is very unlikely that the primary and secondary maximums would ever occur at the same receptors. So, it would take a considerable and unreasonably conservative change to the interpollutant trading ratios used in this example before the NAAQS could be threatened based on the total proposed emissions increases from this facility.

At the same time Sasol also conducted an analysis of speciated data at a nearby monitor to further corroborate the ratio analysis. There is a $PM_{2.5}$ monitor within ½ mile of the Sasol's property line, but it does not have speciated data collection. Sasol utilized a representative $PM_{2.5}$ monitor approximately 25 miles away that did have long-term speciated data. Sasol evaluated the $PM_{2.5}$ speciated data from the nearby monitor to support that nitrate is not a large contributer to high $PM_{2.5}$ values on an annual basis or even on the higher daily values in the colder months when nitrates would be expected to yield more secondary $PM_{2.5}$.

Given the close coordination with the respective permitting authorities, it was determined that a more thorough technical demonstration with respect to interpollutant ratios specific to this source and area was not warranted and that the illustrative use of the formerly presumptive interpollutant trading ratios was sufficient to demonstrate that secondary $PM_{2.5}$ formation would not cause or contribute to a violation of the NAAQS. The permit applicant's corroborative analysis of the $PM_{2.5}$ speciated data further supported that the main increase of emissions (NO_x) would not be expected to yield significant levels of secondary $PM_{2.5}$ and the applicable ambient standards will not be exceeded by this project.

Region 6 example:

> **Justification on Secondary $PM_{2.5}$ Approach**
> At a December 13, 2013, meeting and on a January 17, 2014, conference call EPA Region 6 requested an analysis to examine the fraction of sulfate and nitrate in the $PM_{2.5}$ measurements in the study area and additional justification on the modeling approach for secondary $PM_{2.5}$. This document presents the results of the requested analysis.
>
> Secondary $PM_{2.5}$ is formed primarily from reaction of sulfur dioxide (SO_2) emissions to form particulate sulfate and from nitrogen oxides (NO_x) reacting to form particulate nitrate. The approach used to estimate the secondary particulate is described in Section [Secondary Particulate Estimate *(listed below)*].
>
> With regard to NO_x. and SO_2, the Sasol project emissions are dominated by NO_x with annual emissions of 1,595 tons per year compared to SO_2 emissions of only 121 tons per year. EPA requested additional information on the secondary $PM_{2.5}$ formation from nitrate in the colder months.
>
> The $PM_{2.5}$ background monitor is the Westlake monitor located very near the project site. However, this monitor did not record speciated $PM_{2.5}$ data, so it is not possible to compute the sulfate and nitrate fractions at this location. Monitors with speciated $PM_{2.5}$ data include the Port Arthur Memorial School (AIRS: 48-245-0021) in Port Arthur, Texas, the Capitol Baton Rouge (AIRS: 22-033-0009), and the Shreveport (AIRS: 22-015-0008) monitors. The Port Arthur monitor was chosen as being the most representative because it is the closest monitor to the Sasol site and is in a less urban area than the Capitol Baton Rouge monitor and is not as far inland as the Shreveport monitor. The Port Arthur area is also located along the gulf coast and most closely represents the combination of a metropolitan size and industrial presence when compared to the Calcasieu Parish area where Sasol is located.

The Port Arthur monitor, located in Port Arthur, Texas, is approximately 25 miles west of the project. Given the regional nature of $PM_{2.5}$ concentrations, this monitor should be representative of the study area. The most recently available five years of data for this site was for 2006-2010 and was obtained from the USEPA. The data shows that nitrate makes up 2.6 percent of the average of the 24-hour concentrations of $PM_{2.5}$ and 2.3 percent of the 5-year average concentration. On the day with the highest 24-hour average $PM_{2.5}$ measurement, nitrate was 2.2 percent of the $PM_{2.5}$ concentration.

In general, the generation of $PM_{2.5}$ occurs more from nitrate during colder winter months than during the summer. Examination of the worst 10% of $PM_{2.5}$ days during the colder months (November through February) at the Port Arthur monitor for 2006-2010 reveals that the average nitrate contribution is 2.9 percent, only slightly higher than the 5-year average concentration. Thus, even on days with high $PM_{2.5}$ concentrations in the colder months, particulate nitrate is still a relatively small portion of the total $PM_{2.5}$ concentrations.

Based on this relatively low fraction of particulate nitrate in the observed $PM_{2.5}$, and the magnitude of existing NO_x emissions in the area, it is clear that secondary formation of particulate nitrate is not significant in the project area.

Particulate sulfate makes up 29.6 percent of the 5-year average of the 24-hour concentrations and 29.0 percent of the 5-year average concentrations. On the day with the highest 24-hour average $PM_{2.5}$ observation, sulfate was 10.6 percent of the $PM_{2.5}$ concentration.

Table 1 presents the total $PM_{2.5}$ ambient air impact estimated using the formerly approved interpollutant trading ratios. The nitrate equivalent ratio (1.026) is [6.5] times greater than the sulfate equivalent ratio ([1.004]). While sulfate does make up a significant portion of the total $PM_{2.5}$ mass, the projected increase in SO_2 emissions (121 tpy) from the Sasol GTL and LCCP projects are a very small fraction of the total SO_2 emissions in the large industrial area impacting Port Arthur (i.e. Beaumont/Port Arthur, Lake Charles, Houston/Galveston).

An implicit conservatism to the ratio approach that was used by Sasol is that the primary and secondary impacts occur at the same location at the same time. The 24-hour average modeled $PM_{2.5}$ concentration is presented in Figure 1. Examination of this figure reveals that the highest impact occurs very near the Sasol project border. Within a few kilometers of the project site, the concentrations fall significantly from the peak of modeled concentration of 9 $\mu g/m^3$ to less than 3 $\mu g/m^3$. Formation of secondary sulfate and nitrate particulate is a fairly slow process with conversion rates taking many hours to days. Thus, the peak secondary impacts are expected to occur well downwind of the peak primary impacts.

Given this information, the study team is comfortable that the ambient ratio analysis

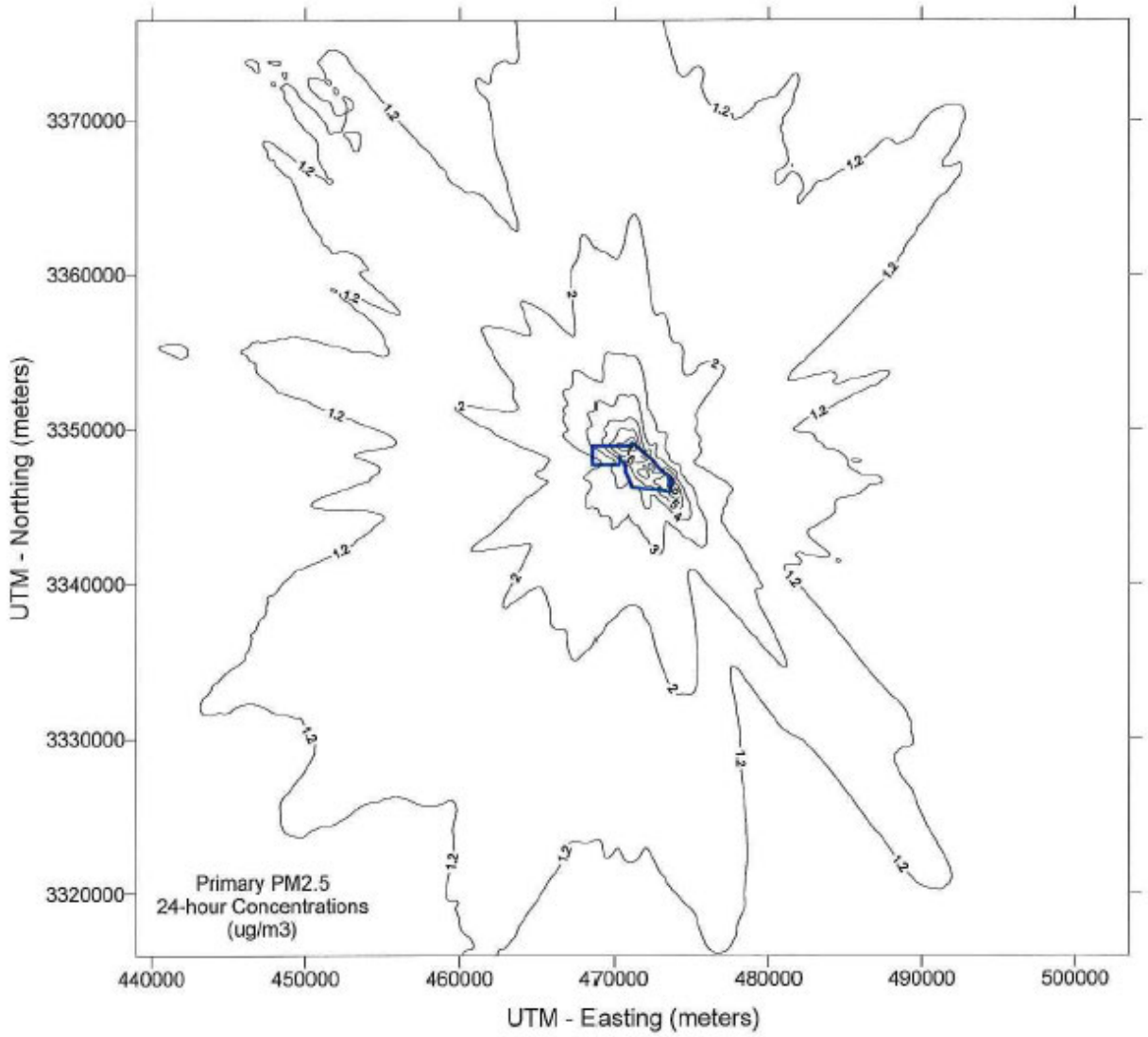
presented in the ozone and secondary $PM_{2.5}$ modeling report is an appropriate approach to estimating the secondary $PM_{2.5}$ impacts for the project.

Table 1: Total $PM_{2.5}$ (Primary + Secondary) Ambient Air Impacts with Comparison with NAAQS and PSD Increment Limits

	Modeled Primary $PM_{2.5}$ ($\mu g/m^3$)	Sulfate Equivalent Ratio	Nitrate Equivalent Ratio	Primary and Secondary $PM_{2.5}$ ($\mu g/m^3$)	PM2.5 Standard ($\mu g/m^3$)
NAAQS 24-hour	6	1.004	1.026	6.2 + 23 = 29.2	35
NAAQS Annual	1.6	1.004	1.026	1.6 + 9.8 = 11.4	12
PSD Increment 24-hour	7.6	1.004	1.026	7.8	9
PSD Increment Annual	1.5	1.004	1.026	1.5	4

Monitored background concentrations for $PM_{2.5}$ 24-hour is 23 $\mu g/m^3$ and for PM2.5 annual is 9.8 $\mu g/m^3$.

Figure 1: Sasol Primary 24-hour Maximum PM2.5 Concentration Isopleth ($\mu g/m^3$). Peak value is 8.6 $\mu g/m^3$.



[Secondary Particulate Estimate]

Recent EPA guidance (EPA March 2013) has suggested the need to examine secondary particulate formation. Directly emitted sulfur or nitrogen compounds are likely to react with available water and other pollutants in secondary reactions to form particulate ammonium sulfate –$(NH_4)_2SO_4$ or ammonium nitrate –NH_4NO_3. These latter compounds are formed primarily downwind of the specific sources of concern, given reaction times, ambient temperature and other environmental factors. The sulfur compounds emitted by the two projects are in the form of SO_2. The nitrogen compounds emitted by the two projects are in the form of NO_x. The Sasol projects (GTL and LCCP combined) would have 1,595 tpy of NO_x, 121 tpy SO_2, and 612 tpy of direct $PM_{2.5}$ emissions.

The NACAA/EPA recommendation to account for secondary $PM_{2.5}$ formation is to divide the projected emissions by a region average offset ratio. The national ratio for SO_2 is 40 and for NO_x is 100 for western states and 200 for eastern states. To be conservative, the western value was used in the analysis since it estimates a higher secondary ratio. The total $PM_{2.5}$ emissions are calculated by multiplying the primary $PM_{2.5}$ modeled concentration by the ratio obtained from the secondary equivalent $PM_{2.5}$ calculation.

For the Sasol combined project emissions the formulas are:

Total Equivalent $PM_{2.5}$ = Primary $PM_{2.5}$ + (SO_2/40) + (NO_x/100) = 612 + (121/400) + (1,595/100) = 631.0 ton/year

Total $PM_{2.5}$ Impact ($\mu g/m^3$) = Primary $PM_{2.5}$ Impact ($\mu g/m^3$) * (Total Equivalent Primary $PM_{2.5}$ (tpy) / Primary $PM_{2.5}$ (tpy))

Total Equivalent $PM_{2.5}$ / Primary $PM_{2.5}$ = 631.0 tpy / 612 tpy = 1.03

Hence the modeled impacts for $PM_{2.5}$ could be increased by a factor of 1.03 [(1.004 for SO_2 and 1.026 for NO_x)] to account for the secondary formation for those sources emitting significant amounts of secondary $PM_{2.5}$ precursor emissions.

Appendix E: Example of the background monitoring data calculations for a Second Tier 24-hour modeling analysis

This appendix provides an illustrative example of the calculations and data sorting recommendations for the background monitoring data to be used in a Second Tier 24-hour $PM_{2.5}$ modeling analysis. In this example, it was determined through discussion and coordination with the appropriate permitting authority that the impacts from the project source's primary $PM_{2.5}$ emissions were most prominent during the cool season and were not temporally correlated with background $PM_{2.5}$ levels that were typical highest during the warm season. So, combining the modeled and monitored contributions through a First Tier 24-hour $PM_{2.5}$ modeling analysis was determined to be potentially overly conservative. Extending the compliance demonstration to a Second Tier analysis allows for a more refined and appropriate assessment of the cumulative impacts on the primary $PM_{2.5}$ emissions in this particular situation.

The example provided is from an idealized Federal Reference Method (FRM) $PM_{2.5}$ monitoring site that operates on a daily (1-in-1 day) frequency with 100% data completeness. In this case, the annual 98^{th} percentile concentration is the 8^{th} highest concentration of the year. In most cases, the FRM monitoring site will likely operate on a 1-and-3 day frequency and will also likely have missing data due to monitor maintenance or collected data not meeting all of the quality assurance criteria. Please reference Appendix N to 40 CFR Part 50 to determine the appropriate 98^{th} percentile rank of the monitored data based on the monitor sampling frequency and valid number of days sampled during each year.

The appropriate seasonal (or quarterly) background concentrations to be included as inputs to the AERMOD model per a Second Tier 24-hour $PM_{2.5}$ modeling analysis are as follows:

- Step 1 – Start with the most recent 3-years of representative background $PM_{2.5}$ ambient monitoring data that are being used to develop the monitored background $PM_{2.5}$ design value. In this example, the 3-years of 2008 to 2010 are being used to determine the monitored design value.

- Step 2 – For each year, determine the appropriate rank for the daily 98^{th} percentile $PM_{2.5}$ concentration. Again, this idealized example is from a 1-in-1 day monitor with 100% data completeness. So, the 8^{th} highest concentration of each year is the 98^{th} percentile $PM_{2.5}$ concentration. The 98^{th} percentile $PM_{2.5}$ concentration for 2008 is highlighted in Table E-1. The full concentration data from 2009 and 2010 are not shown across the steps in this Appendix for simplicity but would be similar to that of 2008.

- Step 3 – Remove from further consideration in this analysis the $PM_{2.5}$ concentrations from each year that are greater than the 98^{th} percentile $PM_{2.5}$ concentration. In the case presented for a 1-in-1 day monitor, the top 7 concentrations are removed. If the monitor were a 1-in-3 day monitor, only the top 2 concentrations would be removed. The resultant dataset after the top 7 concentrations have been removed from further consideration in this analysis for 2008 is presented in Table E-2.

- Step 4 – For each year, divide the resultant annual dataset of the monitored data equal to or less than the 98th percentile $PM_{2.5}$ concentration into each season (or quarter). For 2008, the seasonal subsets are presented in Table E-3.

- Step 5 – Determine the maximum $PM_{2.5}$ concentration from each of the seasonal (or quarterly) subsets created in Step 4 for each year. The maximum $PM_{2.5}$ concentration from each season for 2008 is highlighted in Table E-3.

- Step 6 – Average the seasonal (or quarterly) maximums from Step 5 across the three years of monitoring data to create the four seasonal background PM2.5 concentrations to be included as inputs to the AERMOD model. These averages for the 2008 to 2010 dataset used in this example are presented in Table E-4. As noted above, the full concentration data from 2009 and 2010 are not shown across the steps in this Appendix for simplicity, but the seasonal maximums from 2009 and 2010 presented in Table E-4 were determined by following the previous five steps similar to that of 2008.

Table E-1. 2008 Daily $PM_{2.5}$ Concentrations

Date	Conc.	Date	Conc.	Date	Conc.	Date	Conc.	Date	Conc.	Date	Conc.	Date	Conc.	Date	Conc.
1-Jan	10.4	16-Feb	15.1	2-Apr	10.5	18-May	11.1	3-Jul	17.1	18-Aug	18.7	3-Oct	12.3	18-Nov	4.4
2-Jan	5.4	17-Feb	11.8	3-Apr	8.2	19-May	7.7	4-Jul	19.8	19-Aug	21.5	4-Oct	19.5	19-Nov	8.2
3-Jan	10.0	18-Feb	3.4	4-Apr	9.7	20-May	13.6	5-Jul	14.3	20-Aug	20.1	5-Oct	23.7	20-Nov	11.1
4-Jan	16.4	19-Feb	4.5	5-Apr	6.9	21-May	12.1	6-Jul	11.5	21-Aug	18.4	6-Oct	19.8	21-Nov	5.3
5-Jan	11.2	20-Feb	4.8	6-Apr	6.3	22-May	10.0	7-Jul	14.3	22-Aug	16.7	7-Oct	21.7	22-Nov	8.9
6-Jan	11.1	21-Feb	11.9	7-Apr	7.9	23-May	13.3	8-Jul	12.2	23-Aug	13.8	8-Oct	12.2	23-Nov	14.0
7-Jan	10.2	22-Feb	20.1	8-Apr	9.8	24-May	11.2	9-Jul	11.1	24-Aug	19.0	9-Oct	5.1	24-Nov	12.7
8-Jan	11.4	23-Feb	11.4	9-Apr	16.5	25-May	17.7	10-Jul	9.7	25-Aug	17.6	10-Oct	10.2	25-Nov	9.7
9-Jan	8.1	24-Feb	19.3	10-Apr	13.3	26-May	14.2	11-Jul	16.4	26-Aug	15.4	11-Oct	10.7	26-Nov	12.8
10-Jan	9.4	25-Feb	18.2	11-Apr	11.0	27-May	15.4	12-Jul	21.5	27-Aug	12.6	12-Oct	5.6	27-Nov	16.6
11-Jan	5.7	26-Feb	12.8	12-Apr	8.8	28-May	13.9	13-Jul	25.1	28-Aug	12.1	13-Oct	5.9	28-Nov	17.2
12-Jan	8.9	27-Feb	5.5	13-Apr	6.3	29-May	9.3	14-Jul	11.7	29-Aug	10.1	14-Oct	9.7	29-Nov	16.6
13-Jan	18.1	28-Feb	9.7	14-Apr	5.1	30-May	14.5	15-Jul	18.9	30-Aug	17.2	15-Oct	12.8	30-Nov	4.5
14-Jan	11.0	29-Feb	12.1	15-Apr	7.9	31-May	20.5	16-Jul	28.9	31-Aug	19.9	16-Oct	16.4	1-Dec	7.5
15-Jan	11.8	1-Mar	9.6	16-Apr	8.2	1-Jun	15.3	17-Jul	27.6	1-Sep	19.4	17-Oct	12.0	2-Dec	10.6
16-Jan	10.7	2-Mar	5.6	17-Apr	14.7	2-Jun	11.5	18-Jul	12.8	2-Sep	18.2	18-Oct	7.9	3-Dec	16.7
17-Jan	10.0	3-Mar	12.5	18-Apr	22.5	3-Jun	17.9	19-Jul	6.2	3-Sep	24.0	19-Oct	6.6	4-Dec	12.5
18-Jan	15.6	4-Mar	7.1	19-Apr	12.8	4-Jun	21.1	20-Jul	20.1	4-Sep	15.4	20-Oct	8.1	5-Dec	7.3
19-Jan	18.0	5-Mar	4.9	20-Apr	6.9	5-Jun	17.9	21-Jul	26.5	5-Sep	12.4	21-Oct	12.2	6-Dec	10.4
20-Jan	6.6	6-Mar	9.9	21-Apr	7.5	6-Jun	17.6	22-Jul	16.9	6-Sep	12.5	22-Oct	4.6	7-Dec	13.4
21-Jan	7.4	7-Mar	11.2	22-Apr	6.0	7-Jun	15.0	23-Jul	12.8	7-Sep	15.8	23-Oct	6.1	8-Dec	10.5
22-Jan	13.5	8-Mar	5.5	23-Apr	9.1	8-Jun	22.3	24-Jul	7.9	8-Sep	23.4	24-Oct	4.6	9-Dec	9.3
23-Jan	16.0	9-Mar	8.8	24-Apr	10.3	9-Jun	27.9	25-Jul	15.7	9-Sep	11.5	25-Oct	4.5	10-Dec	6.5
24-Jan	9.4	10-Mar	11.0	25-Apr	12.0	10-Jun	21.6	26-Jul	24.9	10-Sep	6.0	26-Oct	10.5	11-Dec	3.0
25-Jan	12.6	11-Mar	12.1	26-Apr	12.5	11-Jun	19.4	27-Jul	22.2	11-Sep	11.8	27-Oct	6.4	12-Dec	3.5
26-Jan	13.6	12-Mar	9.7	27-Apr	11.3	12-Jun	21.2	28-Jul	17.5	12-Sep	10.7	28-Oct	4.6	13-Dec	10.2
27-Jan	16.1	13-Mar	15.1	28-Apr	7.6	13-Jun	29.1	29-Jul	19.1	13-Sep	7.6	29-Oct	5.6	14-Dec	17.6
28-Jan	10.0	14-Mar	21.6	29-Apr	7.4	14-Jun	15.6	30-Jul	21.1	14-Sep	7.5	30-Oct	7.6	15-Dec	12.4
29-Jan	10.4	15-Mar	16.6	30-Apr	11.4	15-Jun	14.8	31-Jul	18.0	15-Sep	7.1	31-Oct	11.2	16-Dec	9.7
30-Jan	6.9	16-Mar	7.9	1-May	12.6	16-Jun	17.8	1-Aug	16.3	16-Sep	7.7	1-Nov	16.2	17-Dec	7.0
31-Jan	4.9	17-Mar	9.6	2-May	10.0	17-Jun	12.6	2-Aug	19.3	17-Sep	11.3	2-Nov	17.3	18-Dec	7.9
1-Feb	5.4	18-Mar	10.3	3-May	11.2	18-Jun	10.5	3-Aug	17.9	18-Sep	16.8	3-Nov	18.3	19-Dec	6.9
2-Feb	7.1	19-Mar	8.4	4-May	10.4	19-Jun	15.0	4-Aug	25.1	19-Sep	14.8	4-Nov	8.9	20-Dec	8.1
3-Feb	10.9	20-Mar	4.9	5-May	15.7	20-Jun	22.7	5-Aug	29.3	20-Sep	8.0	5-Nov	5.8	21-Dec	4.9
4-Feb	12.1	21-Mar	8.7	6-May	16.1	21-Jun	18.7	6-Aug	19.1	21-Sep	10.8	6-Nov	8.6	22-Dec	7.7
5-Feb	17.1	22-Mar	13.3	7-May	16.8	22-Jun	15.2	7-Aug	14.0	22-Sep	14.5	7-Nov	15.0	23-Dec	7.7
6-Feb	10.3	23-Mar	12.2	8-May	14.5	23-Jun	16.8	8-Aug	10.8	23-Sep	21.2	8-Nov	8.3	24-Dec	10.5
7-Feb	4.0	24-Mar	10.3	9-May	11.7	24-Jun	15.1	9-Aug	15.0	24-Sep	8.6	9-Nov	10.0	25-Dec	6.5
8-Feb	9.7	25-Mar	11.9	10-May	9.0	25-Jun	20.7	10-Aug	21.7	25-Sep	1.2	10-Nov	12.8	26-Dec	7.6
9-Feb	11.5	26-Mar	20.1	11-May	6.7	26-Jun	23.0	11-Aug	14.3	26-Sep	16.0	11-Nov	11.8	27-Dec	13.3
10-Feb	3.0	27-Mar	22.5	12-May	7.9	27-Jun	17.8	12-Aug	14.7	27-Sep	12.1	12-Nov	14.8	28-Dec	6.4
11-Feb	5.5	28-Mar	18.2	13-May	8.3	28-Jun	12.4	13-Aug	13.0	28-Sep	18.0	13-Nov	14.5	29-Dec	3.7
12-Feb	18.9	29-Mar	10.8	14-May	12.2	29-Jun	12.7	14-Aug	13.5	29-Sep	17.8	14-Nov	7.7	30-Dec	4.7
13-Feb	17.6	30-Mar	6.4	15-May	13.1	30-Jun	8.9	15-Aug	17.5	30-Sep	16.4	15-Nov	3.6	31-Dec	4.4
14-Feb	11.2	31-Mar	3.3	16-May	8.8	1-Jul	7.1	16-Aug	23.9	1-Oct	12.3	16-Nov	4.6		
15-Feb	14.4	1-Apr	7.8	17-May	8.2	2-Jul	13.8	17-Aug	18.4	2-Oct	8.2	17-Nov	7.8		

Annual 98th Percentile Concentration = 21.5 µg/m^3

Table E-2. 2008 Daily $PM_{2.5}$ Concentrations Less Than or Equal to the 98th Percentile

Date	Conc.	Date	Conc.	Date	Conc.	Date	Conc.	Date	Conc.	Date	Conc.	Date	Conc.	Date	Conc.
1-Jan	10.4	16-Feb	15.1	2-Apr	10.5	18-May	11.1	3-Jul	17.1	18-Aug	18.7	3-Oct	12.3	18-Nov	4.4
2-Jan	5.4	17-Feb	11.8	3-Apr	8.2	19-May	7.7	4-Jul	19.8	19-Aug	21.5	4-Oct	19.5	19-Nov	8.2
3-Jan	10.0	18-Feb	3.4	4-Apr	9.7	20-May	13.6	5-Jul	14.3	20-Aug	20.1	5-Oct	23.7	20-Nov	11.1
4-Jan	16.4	19-Feb	4.5	5-Apr	6.9	21-May	12.1	6-Jul	11.5	21-Aug	18.4	6-Oct	19.8	21-Nov	5.3
5-Jan	11.2	20-Feb	4.8	6-Apr	6.3	22-May	10.0	7-Jul	14.3	22-Aug	16.7	7-Oct	21.7	22-Nov	8.9
6-Jan	11.1	21-Feb	11.9	7-Apr	7.9	23-May	13.3	8-Jul	12.2	23-Aug	13.8	8-Oct	12.2	23-Nov	14.0
7-Jan	10.2	22-Feb	20.1	8-Apr	9.8	24-May	11.2	9-Jul	11.1	24-Aug	19.0	9-Oct	5.1	24-Nov	12.7
8-Jan	11.4	23-Feb	11.4	9-Apr	16.5	25-May	17.7	10-Jul	9.7	25-Aug	17.6	10-Oct	10.2	25-Nov	9.7
9-Jan	8.1	24-Feb	19.3	10-Apr	13.3	26-May	14.2	11-Jul	16.4	26-Aug	15.4	11-Oct	10.7	26-Nov	12.8
10-Jan	9.4	25-Feb	18.2	11-Apr	11.0	27-May	15.4	12-Jul	21.5	27-Aug	12.6	12-Oct	5.6	27-Nov	16.6
11-Jan	5.7	26-Feb	12.8	12-Apr	8.8	28-May	13.9	13-Jul	RC	28-Aug	12.1	13-Oct	5.9	28-Nov	17.2
12-Jan	8.9	27-Feb	5.5	13-Apr	6.3	29-May	9.3	14-Jul	11.7	29-Aug	10.1	14-Oct	9.7	29-Nov	16.6
13-Jan	18.1	28-Feb	9.7	14-Apr	5.1	30-May	14.5	15-Jul	18.9	30-Aug	17.2	15-Oct	12.8	30-Nov	4.5
14-Jan	11.0	29-Feb	12.1	15-Apr	7.9	31-May	20.5	16-Jul	RC	31-Aug	19.9	16-Oct	16.4	1-Dec	7.5
15-Jan	11.8	1-Mar	9.6	16-Apr	8.2	1-Jun	15.3	17-Jul	RC	1-Sep	19.4	17-Oct	12.0	2-Dec	10.6
16-Jan	10.7	2-Mar	5.6	17-Apr	14.7	2-Jun	11.5	18-Jul	12.8	2-Sep	18.2	18-Oct	7.9	3-Dec	16.7
17-Jan	10.0	3-Mar	12.5	18-Apr	22.5	3-Jun	17.9	19-Jul	6.2	3-Sep	24.0	19-Oct	6.6	4-Dec	12.5
18-Jan	15.6	4-Mar	7.1	19-Apr	12.8	4-Jun	21.1	20-Jul	20.1	4-Sep	15.4	20-Oct	8.1	5-Dec	7.3
19-Jan	18.0	5-Mar	4.9	20-Apr	6.9	5-Jun	17.9	21-Jul	RC	5-Sep	12.4	21-Oct	12.2	6-Dec	10.4
20-Jan	6.6	6-Mar	9.9	21-Apr	7.5	6-Jun	17.6	22-Jul	16.9	6-Sep	12.5	22-Oct	4.6	7-Dec	13.4
21-Jan	7.4	7-Mar	11.2	22-Apr	6.0	7-Jun	15.0	23-Jul	12.8	7-Sep	15.8	23-Oct	6.1	8-Dec	10.5
22-Jan	13.5	8-Mar	5.5	23-Apr	9.1	8-Jun	22.3	24-Jul	7.9	8-Sep	23.4	24-Oct	4.6	9-Dec	9.3
23-Jan	16.0	9-Mar	8.8	24-Apr	10.3	9-Jun	RC	25-Jul	15.7	9-Sep	11.5	25-Oct	4.5	10-Dec	6.5
24-Jan	9.4	10-Mar	11.0	25-Apr	12.0	10-Jun	21.6	26-Jul	24.9	10-Sep	6.0	26-Oct	10.5	11-Dec	3.0
25-Jan	12.6	11-Mar	12.1	26-Apr	12.5	11-Jun	19.4	27-Jul	22.2	11-Sep	11.8	27-Oct	6.4	12-Dec	3.5
26-Jan	13.6	12-Mar	9.7	27-Apr	11.3	12-Jun	21.2	28-Jul	17.5	12-Sep	10.7	28-Oct	4.6	13-Dec	10.2
27-Jan	16.1	13-Mar	15.1	28-Apr	7.6	13-Jun	RC	29-Jul	19.1	13-Sep	7.6	29-Oct	5.6	14-Dec	17.6
28-Jan	10.0	14-Mar	21.6	29-Apr	7.4	14-Jun	15.6	30-Jul	21.1	14-Sep	7.5	30-Oct	7.6	15-Dec	12.4
29-Jan	10.4	15-Mar	16.6	30-Apr	11.4	15-Jun	14.8	31-Jul	18.0	15-Sep	7.1	31-Oct	11.2	16-Dec	9.7
30-Jan	6.9	16-Mar	7.9	1-May	12.6	16-Jun	17.8	1-Aug	16.3	16-Sep	7.7	1-Nov	16.2	17-Dec	7.0
31-Jan	4.9	17-Mar	9.6	2-May	10.0	17-Jun	12.6	2-Aug	19.3	17-Sep	11.3	2-Nov	17.3	18-Dec	7.9
1-Feb	5.4	18-Mar	10.3	3-May	11.2	18-Jun	10.5	3-Aug	17.9	18-Sep	16.8	3-Nov	18.3	19-Dec	6.9
2-Feb	7.1	19-Mar	8.4	4-May	10.4	19-Jun	15.0	4-Aug	25.1	19-Sep	14.8	4-Nov	8.9	20-Dec	8.1
3-Feb	10.9	20-Mar	4.9	5-May	15.7	20-Jun	22.7	5-Aug	RC	20-Sep	8.0	5-Nov	5.8	21-Dec	4.9
4-Feb	12.1	21-Mar	8.7	6-May	16.1	21-Jun	18.7	6-Aug	19.1	21-Sep	10.8	6-Nov	8.6	22-Dec	7.7
5-Feb	17.1	22-Mar	13.3	7-May	16.8	22-Jun	15.2	7-Aug	14.0	22-Sep	14.5	7-Nov	15.0	23-Dec	7.7
6-Feb	10.3	23-Mar	12.2	8-May	14.5	23-Jun	16.8	8-Aug	10.8	23-Sep	21.2	8-Nov	8.3	24-Dec	10.5
7-Feb	4.0	24-Mar	10.3	9-May	11.7	24-Jun	15.1	9-Aug	15.0	24-Sep	8.6	9-Nov	10.0	25-Dec	6.5
8-Feb	9.7	25-Mar	11.9	10-May	9.0	25-Jun	20.7	10-Aug	21.7	25-Sep	1.2	10-Nov	12.8	26-Dec	7.6
9-Feb	11.5	26-Mar	20.1	11-May	6.7	26-Jun	23.0	11-Aug	14.3	26-Sep	16.0	11-Nov	11.8	27-Dec	13.3
10-Feb	3.0	27-Mar	22.5	12-May	7.9	27-Jun	17.8	12-Aug	14.7	27-Sep	12.1	12-Nov	14.8	28-Dec	6.4
11-Feb	5.5	28-Mar	18.2	13-May	8.3	28-Jun	12.4	13-Aug	13.0	28-Sep	18.0	13-Nov	14.5	29-Dec	3.7
12-Feb	18.9	29-Mar	10.8	14-May	12.2	29-Jun	12.7	14-Aug	13.5	29-Sep	17.8	14-Nov	7.7	30-Dec	4.7
13-Feb	17.6	30-Mar	6.4	15-May	13.1	30-Jun	8.9	15-Aug	17.5	30-Sep	16.4	15-Nov	3.6	31-Dec	4.4
14-Feb	11.2	31-Mar	3.3	16-May	8.8	1-Jul	7.1	16-Aug	23.9	1-Oct	12.3	16-Nov	4.6		
15-Feb	14.4	1-Apr	7.8	17-May	8.2	2-Jul	13.8	17-Aug	18.4	2-Oct	8.2	17-Nov	7.8		

Annual 98th Percentile Concentration = 21.5 µg/m³

RC = Above 98th Percentile and Removed from Consideration

Table E-3. 2008 Daily $PM_{2.5}$ Concentrations Less Than or Equal to the 98th Percentile by Quarter

Season / Quarter 1			
Date	Conc.	Date	Conc.
1-Jan	10.4	16-Feb	15.1
2-Jan	5.4	17-Feb	11.8
3-Jan	10.0	18-Feb	3.4
4-Jan	16.4	19-Feb	4.5
5-Jan	11.2	20-Feb	4.8
6-Jan	11.1	21-Feb	11.9
7-Jan	10.2	22-Feb	20.1
8-Jan	11.4	23-Feb	11.4
9-Jan	8.1	24-Feb	19.3
10-Jan	9.4	25-Feb	18.2
11-Jan	5.7	26-Feb	12.8
12-Jan	8.9	27-Feb	5.5
13-Jan	18.1	28-Feb	9.7
14-Jan	11.0	29-Feb	12.1
15-Jan	11.8	1-Mar	9.6
16-Jan	10.7	2-Mar	5.6
17-Jan	10.0	3-Mar	12.5
18-Jan	15.6	4-Mar	7.1
19-Jan	18.0	5-Mar	4.9
20-Jan	6.6	6-Mar	9.9
21-Jan	7.4	7-Mar	11.2
22-Jan	13.5	8-Mar	5.5
23-Jan	16.0	9-Mar	8.8
24-Jan	9.4	10-Mar	11.0
25-Jan	12.6	11-Mar	12.1
26-Jan	13.6	12-Mar	9.7
27-Jan	16.1	13-Mar	15.1
28-Jan	10.0	14-Mar	21.6
29-Jan	10.4	15-Mar	16.6
30-Jan	6.9	16-Mar	7.9
31-Jan	4.9	17-Mar	9.6
1-Feb	5.4	18-Mar	10.3
2-Feb	7.1	19-Mar	8.4
3-Feb	10.9	20-Mar	4.9
4-Feb	12.1	21-Mar	8.7
5-Feb	17.1	22-Mar	13.3
6-Feb	10.3	23-Mar	12.2
7-Feb	4.0	24-Mar	10.3
8-Feb	9.7	25-Mar	11.9
9-Feb	11.5	26-Mar	20.1
10-Feb	3.0	27-Mar	22.5
11-Feb	5.5	28-Mar	18.2
12-Feb	18.9	29-Mar	10.8
13-Feb	17.6	30-Mar	6.4
14-Feb	11.2	31-Mar	3.3
15-Feb	14.4		
Seasonal / Quarterly Maximum			22.5

Season / Quarter 2			
Date	Conc.	Date	Conc.
1-Apr	7.8	17-May	8.2
2-Apr	10.5	18-May	11.1
3-Apr	8.2	19-May	7.7
4-Apr	9.7	20-May	13.6
5-Apr	6.9	21-May	12.1
6-Apr	6.3	22-May	10.0
7-Apr	7.9	23-May	13.3
8-Apr	9.8	24-May	11.2
9-Apr	16.5	25-May	17.7
10-Apr	13.3	26-May	14.2
11-Apr	11.0	27-May	15.4
12-Apr	8.8	28-May	13.9
13-Apr	6.3	29-May	9.3
14-Apr	5.1	30-May	14.5
15-Apr	7.9	31-May	20.5
16-Apr	8.2	1-Jun	15.3
17-Apr	14.7	2-Jun	11.5
18-Apr	22.5	3-Jun	17.9
19-Apr	12.8	4-Jun	21.1
20-Apr	6.9	5-Jun	17.9
21-Apr	7.5	6-Jun	17.6
22-Apr	6.0	7-Jun	15.0
23-Apr	9.1	8-Jun	22.3
24-Apr	10.3	9-Jun	RC
25-Apr	12.0	10-Jun	21.6
26-Apr	12.5	11-Jun	19.4
27-Apr	11.3	12-Jun	21.2
28-Apr	7.6	13-Jun	RC
29-Apr	7.4	14-Jun	15.6
30-Apr	11.4	15-Jun	14.8
1-May	12.6	16-Jun	17.8
2-May	10.0	17-Jun	12.6
3-May	11.2	18-Jun	10.5
4-May	10.4	19-Jun	15.0
5-May	15.7	20-Jun	22.7
6-May	16.1	21-Jun	18.7
7-May	16.8	22-Jun	15.2
8-May	14.5	23-Jun	16.8
9-May	11.7	24-Jun	15.1
10-May	9.0	25-Jun	20.7
11-May	6.7	26-Jun	23.0
12-May	7.9	27-Jun	17.8
13-May	8.3	28-Jun	12.4
14-May	12.2	29-Jun	12.7
15-May	13.1	30-Jun	8.9
16-May	8.8		
Seasonal / Quarterly Maximum			23.0

Season / Quarter 3			
Date	Conc.	Date	Conc.
1-Jul	7.1	16-Aug	23.9
2-Jul	13.8	17-Aug	18.4
3-Jul	17.1	18-Aug	18.7
4-Jul	19.8	19-Aug	21.5
5-Jul	14.3	20-Aug	20.1
6-Jul	11.5	21-Aug	18.4
7-Jul	14.3	22-Aug	16.7
8-Jul	12.2	23-Aug	13.8
9-Jul	11.1	24-Aug	19.0
10-Jul	9.7	25-Aug	17.6
11-Jul	16.4	26-Aug	15.4
12-Jul	21.5	27-Aug	12.6
13-Jul	RC	28-Aug	12.1
14-Jul	11.7	29-Aug	10.1
15-Jul	18.9	30-Aug	17.2
16-Jul	RC	31-Aug	19.9
17-Jul	RC	1-Sep	19.4
18-Jul	12.8	2-Sep	18.2
19-Jul	6.2	3-Sep	24.0
20-Jul	20.1	4-Sep	15.4
21-Jul	RC	5-Sep	12.4
22-Jul	16.9	6-Sep	12.5
23-Jul	12.8	7-Sep	15.8
24-Jul	7.9	8-Sep	23.4
25-Jul	15.7	9-Sep	11.5
26-Jul	24.9	10-Sep	6.0
27-Jul	22.2	11-Sep	11.8
28-Jul	17.5	12-Sep	10.7
29-Jul	19.1	13-Sep	7.6
30-Jul	21.1	14-Sep	7.5
31-Jul	18.0	15-Sep	7.1
1-Aug	16.3	16-Sep	7.7
2-Aug	19.3	17-Sep	11.3
3-Aug	17.9	18-Sep	16.8
4-Aug	25.1	19-Sep	14.8
5-Aug	RC	20-Sep	8.0
6-Aug	19.1	21-Sep	10.8
7-Aug	14.0	22-Sep	14.5
8-Aug	10.8	23-Sep	21.2
9-Aug	15.0	24-Sep	8.6
10-Aug	21.7	25-Sep	1.2
11-Aug	14.3	26-Sep	16.0
12-Aug	14.7	27-Sep	12.1
13-Aug	13.0	28-Sep	18.0
14-Aug	13.5	29-Sep	17.8
15-Aug	17.5	30-Sep	16.4
Seasonal / Quarterly Maximum			25.1

Season / Quarter 4			
Date	Conc.	Date	Conc.
1-Oct	12.3	16-Nov	4.6
2-Oct	8.2	17-Nov	7.8
3-Oct	12.3	18-Nov	4.4
4-Oct	19.5	19-Nov	8.2
5-Oct	23.7	20-Nov	11.1
6-Oct	19.8	21-Nov	5.3
7-Oct	21.7	22-Nov	8.9
8-Oct	12.2	23-Nov	14.0
9-Oct	5.1	24-Nov	12.7
10-Oct	10.2	25-Nov	9.7
11-Oct	10.7	26-Nov	12.8
12-Oct	5.6	27-Nov	16.6
13-Oct	5.9	28-Nov	17.2
14-Oct	9.7	29-Nov	16.6
15-Oct	12.8	30-Nov	4.5
16-Oct	16.4	1-Dec	7.5
17-Oct	12.0	2-Dec	10.6
18-Oct	7.9	3-Dec	16.7
19-Oct	6.6	4-Dec	12.5
20-Oct	8.1	5-Dec	7.3
21-Oct	12.2	6-Dec	10.4
22-Oct	4.6	7-Dec	13.4
23-Oct	6.1	8-Dec	10.5
24-Oct	4.6	9-Dec	9.3
25-Oct	4.5	10-Dec	6.5
26-Oct	10.5	11-Dec	3.0
27-Oct	6.4	12-Dec	3.5
28-Oct	4.6	13-Dec	10.2
29-Oct	5.6	14-Dec	17.6
30-Oct	7.6	15-Dec	12.4
31-Oct	11.2	16-Dec	9.7
1-Nov	16.2	17-Dec	7.0
2-Nov	17.3	18-Dec	7.9
3-Nov	18.3	19-Dec	6.9
4-Nov	8.9	20-Dec	8.1
5-Nov	5.8	21-Dec	4.9
6-Nov	8.6	22-Dec	7.7
7-Nov	15.0	23-Dec	7.7
8-Nov	8.3	24-Dec	10.5
9-Nov	10.0	25-Dec	6.5
10-Nov	12.8	26-Dec	7.6
11-Nov	11.8	27-Dec	13.3
12-Nov	14.8	28-Dec	6.4
13-Nov	14.5	29-Dec	3.7
14-Nov	7.7	30-Dec	4.7
15-Nov	3.6	31-Dec	4.4
Seasonal / Quarterly Maximum			23.7

Seasonal / Quarterly Maximum Concentration
RC = Above 98th Percentile and Removed from Consideration

Table E-4. Resulting Average of Seasonal (or Quarterly) Maximums for Inclusion into AERMOD

Seasonal / Quarterly Average Highest Monitored Concentration

(From Annual Datasets Equal To and Less Than the 98th Percentile)

	Q1	Q2	Q3	Q4
2008	22.5	23.0	25.1	23.7
2009	21.1	20.7	21.2	19.8
2010	20.7	22.6	23.5	20.7
Average	**21.433**	**22.100**	**23.267**	**21.400**

(Note, the complete datasets for 2009 and 2010 are not shown in Appendix E but would follow the same steps as for 2008)

United States
Environmental Protection
Agency

Office of Air Quality Planning and Standards
Air Quality Assessment Division
Research Triangle Park, NC

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EXHIBIT 13

to Sierra Club Comments

An official website of the United States government.

Sierra Club TEP RICE Comments
Exhibit 13

Close

We've made some changes to EPA.gov. If the information you are looking for is not here, you may be able to find it on the EPA Web Archive or the January 19, 2017 Web Snapshot.

United States Environmental Protection Agency

NAAQS Table

The Clean Air Act, which was last amended in 1990, requires EPA to set National Ambient Air Quality Standards (40 CFR part 50) for pollutants considered harmful to public health and the environment. The Clean Air Act identifies two types of national ambient air quality standards. ***Primary standards*** provide public health protection, including protecting the health of "sensitive" populations such as asthmatics, children, and the elderly. ***Secondary standards*** provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings.

The EPA has set National Ambient Air Quality Standards for six principal pollutants, which are called "criteria" air pollutants. Periodically, the standards are reviewed and may be revised. The current standards are listed below. Units of measure for the standards are parts per million (ppm) by volume, parts per billion (ppb) by volume, and micrograms per cubic meter of air ($\mu g/m^3$).

Pollutant [links to historical tables of NAAQS reviews]	**Primary/ Secondary**	**Averaging Time**	**Level**	**Form**
Carbon Monoxide (CO)	primary	8 hours	9 ppm	Not to be exceeded more than once per year
		1 hour	35 ppm	
Lead (Pb)	primary and secondary	Rolling 3 month average	0.15 $\mu g/m^3$ (1)	Not to be exceeded
Nitrogen Dioxide (NO_2)	primary	1 hour	100 ppb	98th percentile of 1-hour daily maximum concentrations, averaged over 3 years
	primary and secondary	1 year	53 ppb (2)	Annual Mean

Pollutant [links to historical tables of NAAQS reviews]		Primary/ Secondary	Averaging Time	Level	Form
Ozone (O_3)		primary and secondary	8 hours	0.070 ppm (3)	Annual fourth-highest daily maximum 8-hour concentration, averaged over 3 years
Particle Pollution (PM)	$PM_{2.5}$	primary	1 year	12.0 µg/m^3	annual mean, averaged over 3 years
		secondary	1 year	15.0 µg/m^3	annual mean, averaged over 3 years
		primary and secondary	24 hours	35 µg/m^3	98th percentile, averaged over 3 years
	PM_{10}	primary and secondary	24 hours	150 µg/m^3	Not to be exceeded more than once per year on average over 3 years
Sulfur Dioxide (SO_2)		primary	1 hour	75 ppb (4)	99th percentile of 1-hour daily maximum concentrations, averaged over 3 years
		secondary	3 hours	0.5 ppm	Not to be exceeded more than once per year

(1) In areas designated nonattainment for the Pb standards prior to the promulgation of the current (2008) standards, and for which implementation plans to attain or maintain the current (2008) standards have not been submitted and approved, the previous standards (1.5 µg/m3 as a calendar

quarter average) also remain in effect.

(2) The level of the annual NO2 standard is 0.053 ppm. It is shown here in terms of ppb for the purposes of clearer comparison to the 1-hour standard level.

(3) Final rule signed October 1, 2015, and effective December 28, 2015. The previous (2008) O3 standards additionally remain in effect in some areas. Revocation of the previous (2008) O3 standards and transitioning to the current (2015) standards will be addressed in the implementation rule for the current standards.

(4) The previous SO2 standards (0.14 ppm 24-hour and 0.03 ppm annual) will additionally remain in effect in certain areas: (1) any area for which it is not yet 1 year since the effective date of designation under the current (2010) standards, and (2)any area for which an implementation plan providing for attainment of the current (2010) standard has not been submitted and approved and which is designated nonattainment under the previous SO2 standards or is not meeting the requirements of a SIP call under the previous SO2 standards (40 CFR 50.4(3)). A SIP call is an EPA action requiring a state to resubmit all or part of its State Implementation Plan to demonstrate attainment of the required NAAQS.

Menu of Control Measures for NAAQS Implementation

The Menu of Control Measures (MCM) provides state, local and tribal air agencies with the existing emission reduction measures as well as relevant information concerning the efficiency and cost effectiveness of the measures. State, local and tribal agencies will be able to use this information in developing emission reduction strategies, plans and programs to assure they attain and maintain the National Ambient Air Quality Standards (NAAQS). The MCM is a living document that can be updated with newly available or more current data as it becomes available.

- Menu of Control Measures

LAST UPDATED ON DECEMBER 20, 2016