ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 51

[EPA-R09-OAR-2013-0588**, FRL-]**

Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze and Interstate Visibility Transport Federal Implementation Plan

AGENCY: Environmental Protection Agency (EPA)

ACTION: Proposed rule.

SUMMARY: This proposed Federal Implementation Plan (FIP) addresses the requirements of the Regional Haze Rule (RHR) and interstate visibility transport for the disapproved portions of Arizona's Regional Haze (RH) State Implementation Plan (SIP) as described in our final rule published on July 30, 2013. Our final rule on Arizona's RH SIP partially approved and partially disapproved the State's plan to implement the regional haze program for the first planning period. Today's proposed rule addresses the RHR's requirements for Best Available Retrofit Technology (BART), Reasonable Progress Goals (RPGs) and Long-term Strategy (LTS) as well as the interstate visibility transport requirements for pollutants that affect visibility in Arizona's 12 Class I areas as well as areas in nearby states. The BART sources addressed in this proposed FIP are Tucson Electric Power (TEP) Sundt Generating Station Unit 4, Lhoist Nelson Lime Plant Kilns 1 and 2, ASARCO Incorporated Hayden Smelter, and Freeport-McMoran Inc. (FMMI) Miami Smelter. The sources with proposed controls for reasonable progress are the Phoenix Cement Clarkdale Plant and the CalPortland Cement Rillito Plant.

DATES: Written comments must be submitted to the designated contact at the address below on or before [**Insert date 45 days from date of publication**].

ADDRESSES: See the General Information section for further instructions on where and how to learn more about this proposal, attend a public hearing, or submit comments.

FOR FURTHER INFORMATION CONTACT: Thomas Webb, U.S. EPA, Region 9, Planning Office, Air Division, Air-2, 75 Hawthorne Street, San Francisco, CA 94105. Thomas Webb may be reached at telephone number (415) 947-4139 and via electronic mail at r9azreghaze@epa.gov.

SUPPLEMENTARY INFORMATION:

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I. General Information

A. Definitions

1) The words or initials *Act* or *CAA* mean or refer to the Clean Air Act, unless the context indicates otherwise.

2) The initials *ADEQ* mean or refer to the Arizona Department of Environmental Quality.

3) The words *Arizona* and *State* mean the State of Arizona.

4) The initials *BACT* mean or refer to Best Available Control Technology.

5) The initials *BART* mean or refer to Best Available Retrofit Technology.

6) The initials *BOD* mean or refer to boiler operating day.

7) The term *Class I area* refers to a mandatory Class I Federal area.

8) The initials *CEMS* refers to continuous emission monitoring system or systems.

9) The initials *dv* mean or refer to deciview, a measure of visual range.

10) The words *EPA*, *we*, *us* or *our* mean or refer to the United States Environmental Protection Agency.

11) The initials *FGD* mean or refer to flue gas desulfurization.

12) The initials *FIP* mean or refer to Federal Implementation Plan.

13) The initials *FLM* mean or refer to Federal Land Managers.

14) The initials *IMPROVE* mean or refer to Interagency Monitoring of Protected Visual Environments monitoring network.

15) The initials *IPM* mean or refer to Integrated Planning Model.

16) The initials lb/MMBtu mean or refer to pounds per one million British thermal units.

17) The initials *LDSCR* and *HDSCR* mean or refer to low and high dust Selective Catalytic Reduction, respectively.

18) The initials *LNB* mean or refer to low NO_x burners.

19) The initials *LTS* mean or refer to Long-term Strategy.

20) The initials *MACT* mean or refer to Maximum Achievable Control Technology.

21) The initials *MW* mean or refer to megawatts.

22) The initials *NAAQS* mean or refer to National Ambient Air Quality Standards.

23) The initials *NEI* mean or refer to National Emissions Inventory.

24) The initials *NESCAUM* mean or refer to Northeast States for Coordinated Air Use Management.

25) The initials *NM* mean or refer to National Monument.

26) The initials NO_x mean or refer to nitrogen oxides.

27) The initials *NP* mean or refer to National Park.

28) The initials *NPS* mean or refer to the National Park Service.

29) The initials *NSCR* mean or refer to non-selective catalytic reduction.

30) The initials *NSPS* mean or refer to new source performance standards.

31) The initials *PM* mean or refer to particulate matter.

32) The initials $PM_{2.5}$ mean or refer to fine particulate matter with an aerodynamic diameter of less than 2.5 micrometers.

33) The initials PM_{10} mean or refer to particulate matter with an aerodynamic diameter of less than 10 micrometers.

34) The initials *PSAT* mean or refer to Particulate Source Apportionment Technology.

35) The initials *PSD* mean or refer to Prevention of Significant Deterioration.

36) The initials *PTE* mean or refer to potential to emit.

37) The initials *RH* mean or refer to regional haze.

38) The initials *RHR* mean or refer to the Regional Haze Rule, originally promulgated in 1999 and codified at 40 CFR 51.301-309.

39) The initials *RMC* mean or refer to Regional Modeling Center.

40) The initials *RP* mean or refer to Reasonable Progress.

41) The initials *RPG* or *RPGs* mean or refer to Reasonable Progress Goal(s).

42) The initials *SCR* mean or refer to Selective Catalytic Reduction.

43) The initials *SIP* mean or refer to State Implementation Plan.

44) The initials *SNCR* mean or refer to Selective Non-catalytic Reduction.

45) The initials SO_2 mean or refer to sulfur dioxide.

46) The initials *SOFA* mean or refer to Separated Overfire Air.

47) The initials *SRP* mean or refer to Salt River Project Agricultural Improvement and Power District.

48) The initials *tpy* mean tons per year.

49) The initials *TSD* mean or refer to Technical Support Document.

50) The initials *TSF* mean or refer to tons of stone feed.

51) The initials *ULNB* mean or refer to ultra-low NO_x burners.

52) The initials *URP* mean or refer to Uniform Rate of Progress.

53) The initials *VOC* mean or refer to volatile organic compounds.

54) The initials *WRAP* mean or refer to the Western Regional Air Partnership.

B. Docket

This proposed action relies on documents, information and data that are listed in the index on http://www.regulations.gov under docket number EPA-R09-OAR-2013-0588. Previous proposed and final actions regarding Arizona's RH SIP are under docket number EPA-R09-OAR-2012-0904 and EPA-R09-OAR-2012-0021. Although listed in the index, some information is not publicly available (e.g., Confidential Business Information (CBI)). Certain other material, such as copyrighted material, is publicly available only in hard copy form. Publicly available docket materials are available either electronically at http://www.regulations.gov or in hard copy at the Planning Office of the Air Division, AIR-2, EPA Region 9, 75 Hawthorne Street, San Francisco, CA 94105. EPA requests that you contact the individual listed in the FOR FURTHER INFORMATION CONTACT section to view the hard copy of the docket. You may view the hard copy of the docket Monday through Friday, 9-5:00 PST, excluding Federal holidays.

C. Instructions for Submitting Comments to EPA

Written comments must be submitted on or before [**Insert date 45 days from date of publication**]. Submit your comments, identified by Docket ID No. EPA-R09-OAR-2013-0588, by one of the following methods:

- Federal Rulemaking portal: http://www.regulations.gov. Follow the on-line instructions for submitting comments.
- E-mail: r9azreghaze@epa.gov
- Fax: 415-947-3579 (Attention: Thomas Webb)
- Mail, Hand Delivery or Courier: Thomas Webb, EPA Region 9, Air Division (AIR-2), 75 Hawthorne Street, San Francisco, California 94105. Hand and courier deliveries are only accepted Monday through Friday, 8:30 a.m. to 4:30 p.m., excluding Federal holidays. Special arrangements should be made for deliveries of boxed information.

EPA's policy is to include all comments received in the public docket without change. We may make comments available online at http://www.regulations.gov, including any personal information provided, unless the comment includes information claimed to be CBI or other information for which disclosure is restricted by statute. Do not submit information that you consider to be CBI or that is otherwise protected through http://www.regulations.gov or e-mail. The http://www.regulations.gov web site is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA, without going through http://www.regulations.gov, we will include your e-mail address as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD-ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should not include special characters or any form of encryption, and be free of any defects or viruses.

D. Submitting Confidential Business Information

Do not submit CBI to EPA through http://www.regulations.gov or e-mail. Clearly mark the part or all of the information that you claim as CBI. For CBI information in a disk or CD ROM that you mail to EPA, mark the outside of the disk or CD ROM as CBI and identify electronically within the disk or CD ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, you must submit a copy of the comment that does not contain the information claimed as CBI for inclusion in the public docket. We will not disclose information so marked except in accordance with procedures set forth in 40 CFR part 2.

E. Tips for Preparing Comments

When submitting comments, remember to:

- Identify the rulemaking by docket number and other identifying information (e.g., subject heading, Federal Register date and page number).
- Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.
- Describe any assumptions and provide any technical information and/or data that you used.
- If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.
- Provide specific examples to illustrate your concerns, and suggest alternatives.
- Explain your views as clearly as possible, avoiding profanity or personal threats.
- Make sure to submit your comments by the identified comment period deadline.

To provide opportunities for questions and discussion, EPA will hold an open house prior to the public hearing. During the open house, EPA staff will be available informally to answer questions on our proposed rule. Any comments made to EPA staff during the open house must still be provided formally in writing or orally during a public hearing to be considered in the record. The open house and public hearing schedule is as follows.

F. Public Hearings

EPA will hold two public hearings at the dates, times and locations stated below to accept oral and written comments into the record. To request interpretation services or to request reasonable accommodation for a disability, please contact the person in the FOR FURTHER INFORMATION CONTACT section by February 14, 2014.

Public Hearing in Phoenix:

Date: February 25, 2014.

Open House: 4:00—5:00 p.m.

Public Hearing: 6:00—8:00 p.m.

Location: Phoenix Convention Center, Rooms 150-153, 33 South 3rd Street, Phoenix, Arizona 85004.

Public Hearing in Tucson:

Date: February 26, 2014.

Open House: 4:00—5:00 p.m.

Public Hearing: 6:00—8:00 p.m.

Location: Tucson High Magnet School, Auditorium, 400 North 2nd Avenue, Tucson, Arizona 85705.

The public hearing will provide the public with an opportunity to present views or information concerning the proposed RH FIP for Arizona. EPA may ask clarifying questions during the oral presentations, but will not respond to the presentations at that time. We will consider written statements and supporting information submitted during the comment period with the same weight as any oral comments and supporting information presented at the public hearing. Please consult section I.C, I.D and I.E of this preamble for guidance on how to submit written comments to EPA. We will include verbatim transcripts of the hearing in the docket for this action. The EPA Region 9 web site for the rulemaking, which includes the proposal and information about the public hearing, is at http://www.epa.gov/region9/air/actions.

II. Proposed Actions Background and Overview

A. Background

The Clean Air Act (CAA) establishes as a national goal the prevention of any future, and the remedying of any existing man-made impairment of visibility in 156 national parks and wilderness areas designated as Class I areas. Arizona has a wealth of such areas. The sources addressed in this FIP affect many Class I areas in the State of Arizona and adjacent states. This FIP will ensure that progress is made toward natural visibility conditions at these national treasures, as Congress intended when it directed EPA to improve visibility in national parks and wilderness areas. Please refer to our previous rulemaking on the Arizona RH SIP for additional background regarding the CAA, regional haze and EPA's RHR.[1]

B. Regional Haze

We propose to promulgate a FIP as described in this notice and summarized in this section to address those portions of Arizona's RH SIP that we disapproved on July 30, 2013.[2] We disapproved in part Arizona's BART control analyses and determinations for four sources, Reasonable Progress Goal (RPG) analyses and determinations, and Long-term Strategy (LTS) for making reasonable progress. The proposed FIP includes emission limits, compliance schedules and requirements for equipment maintenance, monitoring, testing, recordkeeping and

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[1] 77 FR 75704, 75707-75702 (December 21, 2012).
[2] 78 FR 46142.

reporting for all affected sources and units. The regulatory language for the proposed FIP requirements is under Part 52 at the end of this notice.

1. Proposed BART Determinations

EPA conducted BART analyses and determinations for four sources: Sundt Generating Station Unit 4, Nelson Lime Plant Kilns 1 and 2, Hayden Smelter and Miami Smelter. The results of our BART evaluations are summarized here for each source and are shown in Table 1. We are seeking comments on our proposals.

Sundt: We propose that Sundt Unit 4 is BART-eligible and subject to BART for sulfur dioxide (SO_2), nitrogen oxides (NO_x) and particulate matter with aerodynamic diameter less than 10 micrometers (PM_{10}). For NO_x, we propose an emission limit of 0.36 lb/MMBtu as BART based upon an annual capacity factor of 0.49, which is consistent with the use of Selective Non-Catalytic Reduction (SNCR) as a control technology. For SO_2, we propose an emission limit of 0.23 lb/MMBtu as BART on a 30-day boiler operating day (BOD) rolling basis, which is consistent with dry sorbent injection (DSI) as a control technology. For PM_{10}, we propose a filterable PM_{10} emission limit of 0.030 lb/MMBtu as BART based on the use of the existing fabric filter baghouse. We also are proposing a switch to natural gas as a better-than-BART alternative to the other proposed controls for all three pollutants.

Nelson Lime Plant: We propose that Nelson Lime Kilns 1 and 2 are subject to BART for NO_x, SO_2 and PM_{10}. For NO_x, we propose a BART emission limit at Kiln 1 of 3.80 lb/ton lime and at Kiln 2 of 2.61 lb/ton lime on a 30-day rolling basis as verified by continuous emission monitoring systems (CEMS). This emission limit is consistent with the use of low-NO_x burners (LNB) and SNCR as control technologies. We propose that BART for SO_2 is an emission limit of 9.32 lb/ton for Kiln 1 and 9.73 lb/ton for Kiln 2 on a 30-day rolling basis, which is consistent with the use of a lower sulfur fuel blend. For PM_{10}, we propose a BART emission limit of 0.12

lb/tons of stone feed (TSF) to control PM_{10} at Kilns 1 and 2 based on the use of the existing fabric filter baghouses. This level of control is commensurate with the MACT standard that applies to this source.

Hayden Smelter: We propose that the Hayden Smelter is subject to BART for NO_x, and propose BART emission limits for NO_x and SO_2. EPA previously approved the State's determination that the Hayden Smelter is subject to BART for SO_2. For NO_x, we propose to find that controlling emissions from the converters and anode furnaces is cost-effective, but would not result in sufficient visibility improvement to warrant the cost. Therefore, we are proposing an annual emission limit of 40 tpy NO_x emissions from the BART-eligible units, which is consistent with current emissions from these units. For SO_2 from the converters, we propose a BART control efficiency of 99.8 percent on a 30-day rolling basis on all SO_2 captured by primary and secondary control systems, which can be achieved with a new double contact acid plant. For SO_2 from the anode furnaces, we propose to find that controlling the 37 tons per year (tpy) of SO_2 emissions from these furnaces, while cost-effective, is not warranted as BART given the potential for only minimal visibility improvement. We propose as an emission limitation for the anode furnace a work practice standard requiring that the furnaces only be charged with blister copper or higher purity copper. We previously approved Arizona's determination that BART for PM_{10} at the Hayden Smelter is no additional controls. In order to ensure the enforceability of this determination, we are proposing to incorporate emission limitations and associated compliance requirements from the National Emission Standard for Hazardous Air Pollutants (NESHAP) for Primary Copper Smelting at 40 CFR Part 63, Subpart QQQ, as part of the LTS.

Miami Smelter: EPA proposes that the Miami Smelter is subject to BART for NO_x, and proposes BART emission limits for NO_x and SO_2. EPA previously approved the State's determination that the Miami Smelter is subject to BART for SO_2. For NO_x, we propose to find that controlling the small amount of emissions from the converters and electric furnace is cost-effective, but would not result in sufficient visibility improvement to warrant the cost. Therefore, we are proposing an annual emission limit of 40 tpy NO_x emissions from the BART-eligible units, which is consistent with current emissions. For SO_2 from the converters, we propose a BART control efficiency of 99.7 percent on a 30-day rolling basis on all SO_2 emissions captured by the primary and secondary control systems as verified by CEMS. This control efficiency could be met through improvements to the primary capture system, construction of a secondary capture system, and application of the MACT QQQ standards to the capture systems. For SO_2 emissions from the electric furnace, we propose as BART the work practice standard to prohibit active aeration. We previously approved Arizona's determination that BART for PM_{10} at the Miami Smelter is the NESHAP for Primary Copper Smelting. We now propose to find that the federally enforceable provisions of the NESHAP, which apply to the Miami Smelter and are incorporated into its Title V Permit, are sufficient to ensure the enforceability of this determination.

TABLE 1–PROPOSED EMISSION LIMITS ON BART SOURCES

Source	Units	Pollutants	Limit	Measure	Corresponding Control Technology
Sundt Generating Station	Unit 4	NO_x	0.36	lb/MMBtu	Selective Non-Catalytic Reduction
		SO_2	0.23		Dry Sorbent Injection
		PM_{10}	0.030		Fabric filter baghouse (existing)
	Unit 4 (Alternative)	NO_x	0.25	lb/MMBtu	Switch to natural gas
		SO_2	0.00064		
		PM_{10}	0.010		
Chemical Lime Nelson	Kiln 1	NO_x	3.80	lb/ton feed	Selective Non-Catalytic Reduction
		SO_2	9.32		Lower sulfur fuel
		PM_{10}	0.12		Fabric filter baghouse (existing)
	Kiln 2	NO_x	2.61		Selective Non-Catalytic Reduction
		SO_2	9.73		Lower sulfur fuel
		PM_{10}	0.12		Fabric filter baghouse (existing)
Hayden Smelter	Converters 1, 3-5	NO_x	40	tpy	None
		SO_2	99.8	Control efficiency	New double contact acid plant

	Anode Furnaces 1, 2	SO_2	None	None	Work practice standard
Miami Smelter	Converters 2-5	NO_x	40	tpy	None
		SO_2	99.7	Control efficiency	Improve primary and new secondary capture systems
	Electric Furnace	SO_2	None	None	Work practice standard

2. Proposed RP Determinations

Point Sources of NO_x: EPA conducted an extensive RP analysis of NO_x point sources that resulted in proposed determinations for nine sources and proposed controls on two sources as shown in Table 2. We are proposing an emissions limit of 2.12 lb/ton on Kiln 4 of the Phoenix Cement Clarkdale Plant based on a 30-day rolling average, which is consistent with SNCR as a control technology. We are proposing an emissions limit of 2.67 lb/ton on Kiln 4 of the CalPortland Cement Rillito Plant based on a 30-day rolling average, which also is consistent with SNCR control technology. We are also taking comment on the possibility of requiring a rolling 12-month cap on NO_x emissions in lieu of a lb/ton emission limit. For Phoenix Cement, this cap would be 947 tpy and apply to Kiln 4. For CalPortland, this cap would be 2,082 tpy and apply to Kilns 1-4.

TABLE 2–PROPOSED EMISSION LIMITS ON RP SOURCES

Source	Units	Pollutants	Limit	Measure	Corresponding Control Technology
Phoenix Cement	Kiln 4	NO_x	2.12	lb/ton	Selective Non-Catalytic Reduction
CalPortland Cement	Kiln 4	NO_x	2.67	lb/ton	Selective Non-Catalytic Reduction

Area Sources of NO_x and SO_2: We propose to find that it is reasonable not to require additional controls on these sources at this time. Primarily, these area source categories are distillate fuel oil combustion in industrial and commercial boilers and in internal combustion engines, and residential natural gas combustion. The State's area sources, which currently contribute a relatively small percentage of the visibility impairment at impacted Class I areas, would benefit from better emission inventories and an improved RP analysis in the next planning period.

Reasonable Progress Goals: EPA is proposing RPGs consistent with a combination of control measures that include those in the approved Arizona RH SIP as well as the approved and proposed Arizona RH FIP. While not quantifying a new set of RPGs based on these control measures, we propose that it is reasonable to assume improved levels of visibility at Arizona's 12 Class I areas by 2018 since the measures in the FIP are significantly beyond what was in the State's plan.

Demonstration of Reasonable Progress: EPA proposes to find that it is not reasonable to provide for rates of progress at the 12 Class I areas consistent with the uniform rate of progress (URP) in this planning period.[3] Given the variety and location of sources contributing to visibility impairment in Arizona, EPA considers it unlikely that Arizona's Class I areas will meet the URP in 2018. We propose to find that the RP analyses underlying our actions on the Arizona SIP[4] and in this proposal are sufficient to demonstrate that it is not reasonable to provide for rates of progress in this planning period that would attain natural conditions by 2064.[5] This is consistent with our proposed and final rules on the Arizona RH SIP in which we approved Arizona's determinations that it is not reasonable to require additional controls to address organic carbon, elemental carbon, coarse mass and fine soil during this planning period.[6] We

[3] 40 CFR 51.308(d)(1)(ii).
[4] See proposed actions at 77 FR 75727-75730, 78 FR 29297-292300 and final action at 78 FR 46172.
[5] 40 CFR 51.308(d)(1)(ii).
[6] See 77 FR 75728 for a discussion on sources of organic carbon and elemental carbon (fires), and 78 FR 29297-29299 for a discussion of coarse mass and fine soil.

also approved the State's decision not to require additional controls (i.e., controls beyond what the State or we determine to be BART) on point sources of SO_2.[7]

3. Long-term Strategy Proposal

EPA proposes to find that provisions in today's proposal in combination with provisions in the approved Arizona SIP and FIP[8] fulfill the requirements of 40 CFR 51.308(d)(3)(ii), (v)(C) and (v)(F). These requirements are to include in the LTS measures needed to achieve emission reductions for out-of-state Class I areas, emissions limitations and schedules for compliance to achieve the reasonable progress goals, and enforceability of emissions limitations and control measures.[9] In today's notice we propose to promulgate emission limits, compliance schedules and other requirements for four BART sources and two RP sources to complete the actions taken in our previous final rule to address these requirements.

C. Interstate Transport of Pollutants that Affect Visibility

We propose that a combination of SIP and FIP measures will satisfy the FIP obligation for the visibility requirement of CAA section 110(a)(2)(D)(i)(II) for the 1997 8-hour ozone, 1997 $PM_{2.5}$, and 2006 $PM_{2.5}$ NAAQS. CAA section 110(a)(2)(D)(i)(II) requires that all SIPs contain adequate provisions to prohibit emissions that will interfere with other states' required measures to protect visibility. We refer to this requirement herein as the interstate transport visibility requirement. ADEQ submitted SIP revisions to address this requirement in 2007 for the 1997 8-hour ozone NAAQS[10] and 1997 $PM_{2.5}$ NAAQS[11] (2007 Transport SIP)[12] and in 2009 for the

[7] 78 FR 46172.
[8] 77 FR 75512-72580, December 5, 2012.
[9] See 78 FR 46173 (codified at 40 CFR 52.145(e)(ii)).
[10] 62 FR 38856, July 18, 1997.
[11] 62 FR 38652, July 18, 1997.
[12] "Revision to the Arizona State Implementation Plan Under Clean Air Act Section 110(a)(2)(D)(i) – Regional Transport," submitted by ADEQ on May 24, 2007.

2006 $PM_{2.5}$ NAAQS[13] (2009 Transport SIP).[14] Each of these SIP revisions indicated that it is appropriate to assess Arizona's interference with other states' measures to protect visibility in conjunction with the State's RH SIP.[15] In our final rule published on July 30, 2013, EPA disapproved these SIP submittals with respect to the interstate transport visibility requirement, triggering the obligation for EPA to promulgate a FIP to address this requirement.[16] Accordingly, today's notice describes our proposed FIP for the interstate transport visibility requirement for the 1997 8-hour ozone, 1997 $PM_{2.5}$, and 2006 $PM_{2.5}$ NAAQS.

III. Review of State and EPA Actions on Regional Haze

A. EPA's Schedule to Act on Arizona's RH SIP

EPA received a notice of intent to sue in January 2011 stating that we had not met the statutory deadline for promulgating RH FIPs and/or approving RH SIPs for dozens of states, including Arizona. This notice was followed by a lawsuit filed by several advocacy groups (Plaintiffs) in August 2011.[17] In order to resolve this lawsuit and avoid litigation, EPA entered into a Consent Decree with the Plaintiffs, which sets deadlines for action for all of the states covered by the lawsuit, including Arizona. This decree was entered and later amended by the United States District Court for the District of Columbia over the opposition of Arizona.[18] Under

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[13] 71 FR 61144, October 17, 2006.

[14] "Arizona State Implementation Plan Revision under Clean Air Act Section 110(a)(1) and (2); 2006 $PM_{2.5}$ NAAQS, 1997 $PM_{2.5}$ NAAQS, and 1997 8-hour Ozone NAAQS," submitted by ADEQ on October 14, 2009, which addressed the requirements of section 110(a)(2)(D)(i) with respect to the 2006 $PM_{2.5}$ NAAQS in Section 2.4 and Appendix B of the submittal.

[15] This concept is also presented in EPA's 2006 guidance memo on interstate transport, which recommended that states make a submission indicating that it was premature, at that time, to determine whether there would be any interference with other states' required measures to protect visibility until the submission and approval of regional haze SIPs. See "Guidance for State Implementation Plan (SIP) Submissions to Meet Current Outstanding Obligations Under Section 110(a)(2)(D)(i) for the [1997] 8-Hour Ozone and PM2.5 National Ambient Air Quality Standards," August 15, 2006.

[16] 78 FR 46142, July 30, 2013.

[17] National Parks Conservation Association v. Jackson (D.D.C. Case 1:11-cv-01548).

[18] National Parks Conservation Association v. Jackson (D.D.C. Case 1:11-cv-01548), Memorandum Order and Opinion (May 25, 2012), Minute Order (July 2, 2012), Minute Order (November 13, 2012) and Minute Order (February 15, 2013).

the terms of the Consent Decree, as amended, EPA is currently subject to three sets of deadlines for taking action on Arizona's RH SIP as listed in Table 3.[19]

TABLE 3—CONSENT DECREE DEADLINES FOR EPA TO ACT ON ARIZONA'S RH SIP

EPA Actions		Proposed Rule	Final Rule
Phase 1	BART determinations for Apache, Cholla and Coronado	July 2, 2012[1]	November 15, 2012[2]
Phase 2	All remaining elements of the Arizona RH SIP	December 8, 2012[3]	July 15, 2013[4]
Phase 3	FIP for disapproved elements of the Arizona RH SIP	January 27, 2014	June 27, 2014

[1] Published in the FEDERAL REGISTER on July 20, 2012, 77 FR 42834.
[2] Published in the FEDERAL REGISTER on December 5, 2012, 77 FR 72512.
[3] Published in the FEDERAL REGISTER on December 21, 2012, 77 FR 75704.
[4] Published in the FEDERAL REGISTER on July 30, 2013, 78 FR 46142.

B. History of State Submittals and EPA Actions

Because four of Arizona's 12 mandatory Class I Federal areas are on the Colorado Plateau, the State had the option of submitting a RH SIP under CAA section 309 of the RHR. A SIP that is approved by EPA as meeting all of the requirements of section 309 is "deemed to comply with the requirements for reasonable progress with respect to the 16 Class I areas [on the Colorado Plateau] for the period from approval of the plan through 2018."[20] When these regulations were first promulgated, 309 SIPs were due no later than December 31, 2003. Accordingly, ADEQ submitted to EPA on December 23, 2003, a 309 SIP for Arizona's four Class I Areas on the Colorado Plateau. ADEQ submitted a revision to its 309 SIP, consisting of rules on emissions trading and smoke management, and a correction to the State's regional haze statutes, on December 31, 2004. EPA approved the smoke management rules submitted as part of the revisions in 2004,[21] but did not propose or take final action on any other portion of the 309 SIP.

[19] *Id.*
[20] 40 CFR 51.309(a).
[21] 71 FR 28270 and 72 FR 25973.

In response to a court decision,[22] EPA revised 40 CFR 51.309 on October 13, 2006, making a number of substantive changes and requiring states to submit revised 309 SIPs by December 17, 2007.[23] Subsequently, ADEQ sent a letter to EPA dated December 24, 2008, acknowledging that it had not submitted a SIP revision to address the requirements of 40 CFR 51.309(d)(4) related to stationary sources and 40 CFR 51.309(g), which governs reasonable progress requirements for Arizona's eight mandatory Class I areas outside of the Colorado Plateau.[24]

EPA made a finding on January 15, 2009, that 37 states, including Arizona, had failed to make all or part of the required SIP submissions to address regional haze.[25] Specifically, EPA found that Arizona failed to submit the plan elements required by 40 CFR 51.309(d)(4) and (g). EPA sent a letter to ADEQ on January 14, 2009, notifying the State of this failure to submit a complete SIP. ADEQ decided to submit a SIP under CAA section 308, instead of under section 309. EPA proposed on February 5, 2013,[26] to disapprove Arizona's 309 SIP except for the smoke management rules that we had previously approved. Our final rule partially disapproving Arizona's 309 SIP was published on August 8, 2013.[27]

ADEQ adopted and transmitted its 2011 RH SIP under section 308 of the RHR to EPA Region 9 in a letter dated February 28, 2011. The SIP was determined complete by operation of law on August 28, 2011.[28] The SIP was properly noticed by the State and available for public comment for 30 days prior to one public hearing held in Phoenix, Arizona, on December 2, 2010. Arizona included in its SIP responses to written comments from EPA Region 9, the National Park Service, the U.S. Forest Service, and other stakeholders including regulated industries and

[22] Center for Energy and Economic Development v. EPA, 398 F.3d 653 (D.C. Circuit 2005).
[23] 71 FR 60612.
[24] Letter from Stephen A. Owens, ADEQ, to Wayne Nastri, EPA, dated December 24, 2008.
[25] 74 FR 2392.
[26] 78 FR 8083.
[27] 78 FR 48326.
[28] CAA section 110(k)(1)(B).

environmental organizations. The 2011 RH SIP is available to review in the docket for this proposed rule.[29]

As shown in Table 3, the first phase of EPA's action on the 2011 RH SIP addressed three BART sources. The final rule for the first phase (a partial approval and partial disapproval of the State's plan and a partial FIP) was signed by the Administrator on November 15, 2012, and published in the **Federal Register** on December 5, 2012. The emission limits on the three sources will improve visibility by reducing NO_x emissions by about 22,700 tons per year. In the second phase of our action, we proposed on December 21, 2012, to approve in part and disapprove in part the remainder of the 2011 RH SIP. ADEQ submitted an Arizona RH SIP Supplement on May 3, 2013, to correct certain deficiencies identified in that proposal. We then proposed on May 20, 2013, to approve in part and disapprove in part the Supplement. Our final rule approving in part and disapproving in part Arizona's RH SIP was published on July 30, 2013.

C. EPA's Authority to Promulgate a FIP

Under CAA section 110(c), EPA is required to promulgate a FIP within 2 years of the effective date of a finding that a state has failed to make a required SIP submission. The FIP requirement is terminated if a state submits a regional haze SIP, and EPA approves that SIP before promulgating a FIP. See 74 FR 2392. Specifically, CAA section 110(c) provides:

> (1) The Administrator shall promulgate a Federal implementation plan at any time within 2 years after the Administrator--

[29] "Arizona State Implementation Plan, Regional Haze under Section 308 of the Federal Regional Haze Rule," February 28, 2011.

> (A) finds that a State has failed to make a required submission or finds that the plan or plan revision submitted by the State does not satisfy the minimum criteria established under [CAA section 110(k)(1)(A)], or
>
> (B) disapproves a State implementation plan submission in whole or in part, unless the State corrects the deficiency, and the Administrator approves the plan or plan revision, before the Administrator promulgates such Federal implementation plan.

Section 302(y) defines the term "Federal implementation plan" in pertinent part, as:

> [A] plan (or portion thereof) promulgated by the Administrator to fill all or a portion of a gap or otherwise correct all or a portion of an inadequacy in a State implementation plan, and which includes enforceable emission limitations or other control measures, means or techniques (including economic incentives, such as marketable permits or auctions or emissions allowances). . .

Thus, because we determined that Arizona failed to timely submit a Regional Haze SIP, we are required to promulgate a Regional Haze FIP for Arizona, unless we first approve a SIP that corrects the non-submittal deficiencies identified in our finding of January 15, 2009. For the reasons explained below, we approved in part and disapproved in part the Arizona Regional Haze SIP on July 30, 2013. Therefore, we are proposing a FIP to address those portions of the SIP that we disapproved.

IV. EPA's BART Process

A. BART Factors

The purpose of the BART analysis is to identify and evaluate the best system of continuous emission reduction based on the BART Guidelines[30] as summarized below. Steps 1 through 3 address the availability, feasibility and effectiveness of retrofit control options. In our analysis of control technology options, we expressly include the emission baseline calculation that is a key factor in determining control effectiveness. Step 4 is the five-factor BART analysis that results in selecting the emission limit that represents BART in Step 5. Following the process steps is a short description of each BART factor.

Step 1 – Identify all available retrofit control technologies.

Step 2 – Eliminate technically infeasible options.

Step 3 – Evaluate control effectiveness of remaining control technologies.

Step 4 – Evaluate impacts and document the results.

- Factor 1: Cost of compliance.
- Factor 2: Energy and non-air quality environmental impacts of compliance.
- Factor 3: Pollution control equipment in use at the source.
- Factor 4: Remaining useful life of the facility.
- Factor 5: Visibility impacts.

Step 5 – Select BART.

Factor 1: Costs of Compliance: The evaluation of costs is an important part of a five-factor analysis because it influences the cost-effectiveness that is compared to the visibility benefits. Estimating the cost of compliance primarily depends on the cost estimates and control effectiveness of each technically feasible BART control option. For each of the four BART facilities evaluated in this section, we state the source of the cost-related information and how it was used in our analysis. While EPA relies primarily on the cost methods in our Control Cost

[30] See July 6, 2005 BART Guidelines, 40 CFR 51, Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations.

Manual, we also rely on verified cost estimates from the companies and cost methods used for specific industries. In some cases, certain capital costs and annual operating costs were developed by our contractor based on actual costs associated with specific types of sources. Where possible, we have conducted new cost analyses considering more recent information from ADEQ or from the four BART facilities. Please refer to the TSD for the detailed cost analyses.

Factor 2: Energy and Non-air Quality Environmental Impacts: In assessing the potential energy impacts of BART control options, we consider direct and indirect effects on energy availability and costs. An example of a direct energy impact is the cost of energy consumption from the control equipment. Examples of non-air quality impacts include safety issues associated with handling and transportation of anhydrous ammonia or the ability to sell fly ash rather than dispose of it.

Factor 3: Pollution Equipment in Use at the Source: The presence of existing pollution control technology at each source is reflected in our BART analysis in two ways. First, we always consider simple retention of existing equipment as a BART candidate. We also consider existing equipment in determining available control technologies that can be used with or replace such equipment. Second, where appropriate, we consider existing equipment in developing baseline emission rates for use in cost calculations and visibility modeling. Pollutant-specific discussions of these issues are included in the following sections.

Factor 4: Remaining Useful Life of the Source: We consider each source's "remaining useful life" as one element of the overall cost analysis as allowed by the BART Guidelines.[31] In cases where we are not aware of any enforceable shut-down date for a particular source or unit, we use a 20-year amortization period as the remaining useful life per the EPA Cost Control Manual.

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[31] 40 CFR Part 51, Appendix Y, section IV.D.4.k.

Factor 5: Anticipated Degree of Visibility Improvement: EPA relied on the CALPUFF modeling system (version 5.8) for visibility modeling, which consists of the CALPUFF dispersion model, the CALMET meteorological data processor, and the CALPOST post-processing program. The initial modeling was performed by our contractor, the University of North Carolina (UNC) at Chapel Hill. In some cases, companies submitted BART analyses including visibility modeling that we used to evaluate visibility benefits. An explanation of the visibility analysis and tables follows this section, a description of the modeling is included in the five-factor discussion for each source, and more details are available in the TSD.

B. Visibility Analysis

EPA estimated the degree of visibility improvement expected to result from various BART control options based on the difference between baseline visibility impacts prior to controls and visibility impacts with controls in operation. Baseline emissions were based on the highest 24-hour emissions from monitored emissions data when available, otherwise from estimates of production rates and emission factors. Control case emissions were derived from the baseline by applying the percent reduction in emission factor expected from the control. Impacts at all Class I areas within 300 km of each facility were assessed. EPA used the CALPUFF model version 5.8[32] to determine the baseline and post-control visibility impacts, following the modeling approach recommended in the BART Guidelines. Our contractor at UNC developed a modeling protocol and carried out most of the modeling and the post-processing of model output into tables of visibility impacts. EPA supplemented this for certain sources with modeling of

[32] EPA relied on version 5.8 of CALPUFF because it is the EPA-approved version promulgated in the Guideline on Air Quality Models (40 CFR 51, Appendix W, section 6.2.1.e; 68 FR 18440, April 15, 2003). EPA updated the specific version to be used for regulatory purposes on June 29, 2007, including minor revisions as of that date; the approved CALPUFF modeling system includes CALPUFF version 5.8, level 070623, and CALMET version 5.8 level 070623. At this time, any other version of the CALPUFF modeling system would be considered an "alternative model", subject to the provisions of Guideline on Air Quality Models section 3.2.2(b), requiring a full theoretical and performance evaluation.

additional control scenarios, corrections to some scenarios and post-processing work, and some sensitivity simulations. Also, EPA performed the modeling for the two smelters. Details of the modeling are in the TSD.

EPA modeled all units (stacks) and pollutants simultaneously for each source. Modeling of all emissions from all units accounts for the chemical interaction between multiple plumes, and between plumes and background concentrations. This also accounts for the fact that deciview benefits from controls on individual units are not strictly additive. As recommended in the BART Guidelines, the 98th percentile daily impact in deciviews is used as the basic metric of visibility impact. EPA relied on the 98th percentile over the merged 2001-2003 period. The alternative of using the average of the three 98th percentiles from 2001, 2002 and 2003 was also calculated, and the results of using it are provided in the TSD, although they differ little from the merged approach. Both are valid indicators of the 98th percentile.[33] EPA also mainly relied on the revised IMPROVE equation for translating pollutant concentrations into deciviews (CALPOST visibility method 8), the recommended method for new visibility analyses. The old IMPROVE equation (method 6) was used by most states in their original SIP submittals and was acceptable at that time. EPA used the best 20 percent of natural background days in calculating delta deciviews. For the original SIP submittals, states were free to use this or the annual average background. Overall, we refer to the method we used as method “8b” (“b” for “best”). Model results using visibility method 6 and annual average background conditions (“a” for average) also are provided in the TSD (i.e., methods 6a, 6b, and 8a, as well as 8b).

C. Explanation of Visibility Tables

[33] For each modeled day, the CALPUFF model provides the highest impact from among the receptor locations for a given Class I area. The baseline impact in the tables is the 98th percentile among these daily values. The improvement in the tables is the difference between that baseline impact and the 98th percentile impact after applying controls. The 98th percentile is represented by the 22nd high over the 2001-2003 period modeled. The TSD includes an alternative, the average of each of the three years’ 8th highs, which yields slightly different values.

For each facility, this notice provides one or more tables of visibility impacts and visibility improvement from controls in deciviews. Each table has the same format: columns list the Class I areas within 300 km of the facility, the distance,[34] baseline modeled visibility impact from the facility for each area, and one or more columns with the modeled visibility improvement from a candidate control option. A modeling run abbreviation, such as "base" or "ctrl2", is included along with a short description of the option. For several facilities, there are two different baselines incorporating different emission assumptions. For these, there are baseline and control columns for each of the two baselines. For Sundt Unit 4, there are separate tables for SO_2 and NO_x controls, and an additional table showing the effect of reductions for both SO_2 and NO_x for the proposed BART controls and for a better-than-BART alternative. At the bottom of each table are five rows showing impacts and improvements from the facility for all the Class I areas considered together, and also two measures of visibility cost-effectiveness. The cost-effectiveness here is "dollars per deciview," where dollars is the annualized total cost of the control in millions of dollars per year, divided by either the sum of deciview improvements over all impacted Class I areas, or the largest single area deciview improvement. Cost-effectiveness in terms of dollars per ton is presented in other tables and has been considered for each source and BART option. The headings for these table rows are:

1) "Cumulative (sum)," the cumulative impact or improvement that is computed as the sum of impact or improvement over all the areas;

2) "Maximum," single largest impact or improvement that is the maximum over all the areas;

[34] The distances given are from the facility to the nearest model receptor location; distances to the actual Class I area boundary may be slightly less. Receptor locations are defined for all Class I areas by the National Park Service. See "Class I Receptors" web site, http://www2.nature.nps.gov/air/maps/Receptors/.

3) "# CIAs >= 0.5 dv," the number of Class I areas having a baseline impact from the source of at least 0.5 dv (or, for the control columns, the number of areas showing improvement of at least 0.5 dv due to the control);

4) "million $/dv (cumul. dv)," annual control cost in millions of dollars per deciview considering the improvement at all the Class I areas together; and

5) "million $/dv (max. dv)," annualized cost per deciview considering the largest single area improvement.

The Federal Land Managers have sometimes used $10 million/dv as a comparison benchmark for the $/dv computed from the maximum, and $20 million/dv as a benchmark for $/dv computed from cumulative deciviews. We have not endorsed the use of these or any other $/dv benchmarks as criteria for making BART determinations.

The TSD for this notice provides bar charts and additional visibility tables, including results for individual modeled years and their average, the old IMPROVE equation, and annual average background conditions instead of best 20 percent. There also are model results for various sensitivity analyses.

V. EPA's Proposed BART FIP

A. Sundt Generating Station Unit 4

Summary: EPA is proposing to find that Sundt Unit 4 is eligible for and subject to BART. EPA is proposing BART emissions limits on Sundt Generating Station Unit 4 for NO_x, SO_2 and PM_{10} based on the corresponding control technologies listed in Table 4 and described in the following BART analyses. For NO_x, we propose an emission limit of 0.36 lb/MMBtu consistent with the use of SNCR. For SO_2, we propose an emission limit of 0.23 lb/MMBtu consistent with the use of DSI. For PM_{10}, we propose a filterable PM_{10} emission limit of 0.03 lb/MMBtu based on the use of the existing fabric filter baghouse. Finally, we are also proposing a switch to natural gas as a better-than-BART alternative.

TABLE 4—SUNDT 4: SUMMARY OF PROPOSED BART DETERMINATIONS

Pollutant	Emission Limit (lb/MMBtu)	Control Technology
NO_x	0.36	Selective Non-Catalytic Reduction
SO_2	0.23	Dry Sorbent Injection
PM_{10}	0.030	Fabric filter baghouse (existing)

Affected Class I Areas: Ten Class I areas are within 300 km of Sundt. Their nearest borders range from 17 km to 247 km away, with Saguaro NP the closest, and Galiuro WA the second closest. The highest baseline visibility impact of Sundt Unit 4 is 3.4 dv at Saguaro. The second highest baseline impact is 1.1 dv at Galiuro. Other areas have visibility impacts of 0.5 dv or less. The cumulative sum of visibility impacts over all the Class I areas is 6.6 dv.

Facility Overview: The Sundt Generating Station is an electric utility power plant located in Tucson, Arizona, operated by Tucson Electric Power. The plant consists of four steam electric boilers and three stationary combustion turbines for a total net generating capacity of approximately 500 megawatts (MW).[35] Sundt Unit 4 is a steam electric boiler that was manufactured in 1964 and placed into operation in about 1967. Unit 4 is a dry bottom wall-fired boiler with a maximum gross capacity of 130 MW when firing coal. Originally designed to fire natural gas and fuel oil, Sundt Unit 4 was converted to also be able to fire coal in the early 1980s as a result of an order issued by the Department of Energy. The unit now fires both coal and natural gas, as explained in more detail below. As part of the coal conversion, the unit was equipped with a fabric filter for particulate matter control. Unit 4 was upgraded in 1999 with LNB and overfire air (OFA) designed to meet Phase II Acid Rain Program requirements. At

[35] As described in Pima DEQ Permit No. 1052, in the TSD.

present, Unit 4 operates with the pollution control equipment and is subject to the emission limits listed in Table 5 that reflects a coal-operating scenario.

TABLE 5—SUNDT 4: CURRENT EMISSION LIMITS AND CONTROL TECHNOLOGY

Pollutant	Emission Limit	Control Device
NO_x	0.46 lb/MMBtu[36]	LNB with OFA
SO_2	1 lb/MMBtu[37]	None
PM_{10}	233 lb/hr[38]	Fabric filter/baghouse

TEP has indicated that the generating capacity of Sundt Unit 4 while firing coal is reduced compared to its capacity using natural gas. As reported to the Energy Information Agency (EIA), Unit 4 has a 173 MW nameplate capacity while firing natural gas. However, the maximum gross capacity at which the unit could operate for a sustained period of time while burning coal is about 130 MW. This is due primarily to the fact that the amount of coal that can be introduced to the boiler is limited by the size of the boiler. Excess coal injection causes the flame to impinge on the back wall of the boiler which damages the boiler tubes.[39] A summary of historical emissions data for a recent period of time is in Table 6.

TABLE 6—SUNDT 4: HISTORICAL EMISSIONS (2008-2012)

Year	Heat Duty (MMBtu/yr)	NO_x		SO_2		Coal (tons)	Natural Gas (MCF)
		(tpy)	(lb/MMBtu)	(tpy)	(lb/MMBtu)		
2012	6,313,719	945	0.297	371	0.118	44,049	4,660,701
2011	5,993,769	1,366	0.445	2,185	0.729	265,111	157,919
2010	6,869,999	1,303	0.368	1,733	0.505	162,212	1,904,433
2009	4,801,971	709	0.285	636	0.265	73,464	2,642,992
2008	8,709,923	1,880	0.429	2,882	0.661	378,956	18,422

Baseline Emissions Calculations: The baseline period, baseline emissions, and capacity factor are three key variables in determining BART that are linked to fuel usage. TEP has

[36] Pima DEQ Permit No. 1052, Attachment F: Phase II Acid Rain Permit.
[37] Pima DEQ Permit No. 1052, Specific Condition II.A.2.b.
[38] As determined by Pima DEQ Permit No. 1052, Specific Condition II.A.1.
[39] TEP's letter dated May 10, 2013, page 2.

indicated that while Sundt Unit 4 predominantly has operated as a coal-fired unit, it has recently expanded its use of natural gas as a result of historically low natural gas prices.[40] As shown in the last column of Table 6, Unit 4 has used much higher amounts of natural gas during 2009-2010 and again in 2012 that are not representative of anticipatable operations based on coal. Accordingly, we use calendar year 2011 emissions when Unit 4 predominately used coal as the baseline period for annual average emission estimates. Although this represents only a single year of emissions data, we consider this period of coal usage, rather than a period of primarily natural gas usage, to represent a realistic depiction of anticipated annual emissions when burning coal.[41] In addition, we rely on an annual capacity factor of 0.49 based on a coal-fired capacity of 130 MW and actual generation from the baseline period of 2011. For visibility modeling, we used baseline emissions for NO_x and SO_2 based on maximum daily emission rates, as reported to EPA's CAMD Acid Rain Program database, for the period from 2008 to 2010. While this time period is prior to the 2011 baseline period used for the annual emission estimates, the highest daily emission rates from 2008 to 2010 correspond to coal usage. Since these maximum daily emission rates still correspond to coal usage, we consider them reasonable estimates of baseline emissions despite the fact that they are drawn from a baseline period different from the one used to estimate annual emission rates. For PM_{10}, the baseline emission rate used in visibility modeling is based on the value in the original Western Regional Air Partnership (WRAP) visibility modeling that reflects the use of coal and the existing fabric filter. For a more detailed analysis of how we determined the baseline period, baseline emissions and capacity factor, please refer to the TSD.

[40] TEP's letter dated May 10, 2013, page 2.
[41] As discussed in the BART Guidelines, 40 CFR Part 51, Appendix Y, section IV.D.4.d.

Modeling Overview: EPA's contactor UNC performed the initial modeling of Sundt's visibility impacts. EPA performed supplemental modeling to correct some minor errors in the initial work and to estimate impacts from additional control scenarios, such as switching entirely to natural gas fuel. EPA also modeled the impacts for the western unit of Saguaro NP, whereas originally only the eastern unit was included. Although only Unit 4 is BART-eligible, all four Sundt units were included in the CALPUFF modeling to more accurately represent the chemistry of the facility's pollutant plume. Baseline emissions for modeling were based on daily CAMD emissions monitoring data for 2008-2010, a period with no changes in pollution controls at the facility. Control case emissions were derived from the baseline by applying the percent reduction expected from the control.

Saguaro NP has an eastern unit, the Rincon Mountain District, and a western unit, the Tucson Mountain District. In the original set of modeling receptor locations developed by the National Park Service, only the eastern unit was included. CALPUFF modeling typically covered only the eastern unit. This is true of modeling by the WRAP, and also of modeling by EPA's contractor UNC, which used the WRAP work as a starting point. A more recent set of NPS modeling receptors from 2008 is available that covers both eastern and western units of Saguaro. For this FIP, EPA remodeled for both Saguaro units where needed for a given facility. The only facilities for which it makes a significant difference are TEP Sundt and CalPortland Cement due to their close proximity to Saguaro.

1. Proposed Eligible and Subject to BART

EPA is proposing to find that Sundt Unit 4 is eligible for and subject to BART. In our final rulemaking on the Arizona RH SIP dated July 30, 2013, we disapproved ADEQ's finding that Sundt Unit 4 was not eligible for BART.[42] In particular, we found that, although this unit was "reconstructed" in 1987, it remains BART-eligible because it did not undergo prevention of significant deterioration (PSD) review at the time of reconstruction.[43] For this reason, we propose to find Sundt Unit 4 is eligible for a BART analysis of the three haze-causing pollutants: NO_x, SO_2 and PM_{10}.

Under the RHR and the BART Guidelines, any BART-eligible source that either "causes" or "contributes" to visibility impairment at any Class I area is subject to BART.[44] EPA previously approved ADEQ's decision to set 0.5 dv as the threshold for determining whether a source contributes to visibility impairment at a given Class I area.[45] In order to determine whether Sundt Unit 4 is subject to BART, EPA's contractor UNC evaluated whether Unit 4 has an impact of 0.5 dv or more at any Class I area. UNC's visibility modeling showed that two Class I areas experienced a 98th percentile impact greater than 0.5 dv due to emissions from Sundt Unit 4.[46] In particular, the 98th percentile impact across the three years modeled was 2.798 dv at Saguaro and 0.839 dv at Galiuro.[47] These results indicate that Sundt Unit 4 causes visibility impairment at Saguaro and contributes to impairment at Galiuro. Therefore, EPA proposes to find that Sundt Unit 4 is subject to BART.

2. Proposed BART Analysis and Determination for NO_x

For our NO_x BART analysis, we identify all available control technologies, eliminate options that are not technically feasible, and evaluate the control effectiveness of the remaining

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[42] 78 FR 46175 (codified at 40 CFR 52.145(e)(2)(i)).
[43] See 78 FR 75722, 78 FR 46151, and "TEP Sundt Unit I4 BART Eligibility Memo" (November 21, 2012).
[44] 40 CFR part 51, appendix Y, section III.A.
[45] 77 FR 46152-53.
[46] Technical Analysis for Arizona and Hawaii Regional Haze FIPs: Report on Identification of Sources Subject to BART, UNC, July 20, 2012, Table 4.
[47] For an expanded discussion of our approach to visibility modeling, please refer to Section III (General Approach to the Five-Factor BART analysis) of the Sundt4 TSD. This approach was used in both determining whether Sundt 4 was subject to BART, as well as in evaluating the visibility factor in the BART analysis.

control options. We then evaluate each technically feasible control in terms of a five-factor BART analysis and propose a determination for BART.

a. Control Technology Availability, Technical Feasibility, and Effectiveness

EPA proposes to find that SNCR and selective catalytic reduction (SCR) are available and technically feasible options to control NO_x emissions with a control efficiency of approximately 50 percent for SNCR and approximately 89 percent for SCR.

SNCR involves the non-catalytic decomposition of NO_x to molecular nitrogen and water. Typical NO_x control efficiencies for SNCR range from 40 to 60 percent, depending on inlet NO_x concentrations, fluctuating flue gas temperatures, residence time, amount and type of nitrogenous reducing agent, mixing effectiveness, acceptable levels of ammonia slip, and presence of interfering chemical substances in the gas stream. Because Sundt Unit 4 already operates with NO_x combustion controls, we have used an SNCR control efficiency of 30 percent from a baseline that includes LNB with OFA. Considering typical combustion control technologies such as LNB and OFA can achieve control efficiencies of about 25 to 30 percent, the result is total control efficiency from an uncontrolled baseline of about 50 percent, which is in the mid-range of SNCR control efficiencies.

SCR is a post-combustion gas treatment technique that uses either ammonia or urea in the presence of a metal-based catalyst to selectively reduce NO_x to molecular nitrogen, water, and oxygen. The catalyst lowers the temperature required for the chemical reaction between NO_x and the reducing agent. Technical factors that impact the effectiveness of this technology include the catalyst reactor design, operating temperature, type of fuel fired, sulfur content of the fuel, design of the ammonia injection system, and the potential for catalyst poisoning. SCR has been installed on numerous coal-fired boilers of varying sizes, and is considered technically feasible. We note that SCRs are classified as a low dust SCR (LDSCR) or high dust SCR (HDSCR). As explained in the TSD, the SCR system considered in this analysis is the HDSCR.

Existing vendor literature and technical studies indicate that SCR systems are capable of achieving approximately 80 to 90 percent control efficiency, and that this emission rate can be achieved on a retrofit basis, particularly when combined with combustion control technology such as LNB.[48] Our contractor used a design emission rate of 0.050 lb/MMBtu (annual average), which in the case of Sundt Unit 4 corresponds to a control efficiency of 89 percent. While this is a value close to the upper range of SCR control efficiency, we consider the use of 0.050 lb/MMBtu appropriate for Sundt Unit 4. A review of Acid Rain Program data indicates that there are up to seven dry-bottom, wall-fired boilers operating with SCR on a retrofit basis that have achieved an annual average emission rate of 0.050 lb/MMBtu or lower in practice.[49] However, there are design differences between Sundt Unit 4 and these other units (i.e., boiler size, coal type and characteristics, and loading profile) that have the potential to affect this comparison. If we receive additional comments that sufficiently document source-specific considerations justifying the use of an emission rate higher than 0.050 lb/MMBtu, we may incorporate such considerations in our selection of BART.

b. BART Analysis for NO_x

Costs of Compliance: In evaluating the costs of compliance for SNCR and SCR, we calculated the control costs ($) and emission reductions (tons/year of pollutant) for each control technology, and developed average cost-effectiveness ($/ton) values. Estimated NO_x emission reductions are summarized in Table 7 and cost-effectiveness numbers are summarized in Table 8

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[48] See “Emissions Control: Cost-Effective Layered Technology for Ultra-Low NOx Control” (2007), “What’s New in SCRs” (2006), and “Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers” (2005).
[49] See spreadsheet “CAMD Wall-fired Coal EGUs.xlsx” in the docket.

for each option. A more detailed version of emission calculations are in our docket[50] and in our contractor's report. The heat duty and capacity factor used in the emission calculations below differ from the values used in the calculations originally prepared by our contractor, due to the unit's lower capacity when burning coal (130 MW) rather than natural gas (173 MW). The heat duty (MMBtu/hr) and capacity factor (0.49) reflect the coal-burning heat duty, rather than the natural gas-burning heat duty.[51]

TABLE 7—SUNDT 4: NO_X CONTROL OPTION EMISSION ESTIMATES

Control Option	Control Efficiency	Emission Factor	Heat Duty	Capacity Factor	NO_x Emission Rate		NO_x Emission Reduction
	%	lb/MMBtu	MMBtu/hr	%	lb/hr	tpy	tpy
Baseline (LNB+OFA)	--	0.445	1,371	0.49	610	1,310	--
SNCR+LNB+OFA	30%	0.312	1,371	0.49	427	917	393
SCR+LNB+OFA	89%	0.050	1,371	0.49	69	147	1,162

Our consideration of the cost of compliance focuses primarily on the cost-effectiveness of each control option as measured in average cost per ton and incremental cost per ton of each control option as shown in Table 8. SCR is the most stringent option with the highest average cost-effectiveness of $5,176/ton, and incremental cost-effectiveness over SNCR of $6,174/ton. Detailed cost calculations can be found in our docket.[52] While we have relied primarily upon the cost calculations prepared by our contractor, we have incorporated certain elements of TEP's analysis[53] into our cost calculations. The most significant revisions to cost estimates include the following:

- We have changed the unit size from 173 MW to 130 MW to reflect the gross capacity of using coal. Although this has the net effect of decreasing certain costs, particularly several operation and maintenance (O&M) costs, the revised capital cost estimates

[50] See spreadsheet "Sundt4 2001-12 Emission Calcs 2014-01-24.xlsx" in the docket.
[51] As noted by TEP in its May 10, 2013 letter, although the calculated capacity factor is different, the annual emissions in tons per year removed do not change significantly, as the change in capacity factor is largely offset by the change in maximum unit gross rating.
[52] See spreadsheet "Sundt4 Control Costs 2014-01-26.xlsx" in the docket.
[53] Letter dated May 10, 2013.

increased for SCR (from $38 million to $45 million) and SNCR (from $2.8 million to $3.1 million).

- We have used a retrofit difficulty value of 1.5 (increased from 1.0) in cost estimates due to certain difficulties associated with retrofit installation of SCR. These difficulties are the result of site congestion and the configuration of the existing boiler structure and coal handling system as noted by TEP.
- We have included the cost of air preheater modifications that TEP stated are necessary in order to accommodate SCR due to site congestion and coal handling configuration.

TABLE 8—SUNDT 4: NO_X CONTROL OPTION COST-EFFECTIVENESS

Control Option	Capital Cost	Annualized Capital Cost	Annual Operating Cost	Total Annual Cost	Emission Reduction	Cost-Effectiveness ($/ton)	
	($)	($)	($)	($/yr)	(tpy)	Ave	Incremental
SNCR	$3,079,089	$290,644	$975,124	$1,265,768	393	$3,222	--
SCR	$45,167,561	$4,263,498	$1,753,975	$6,017,474	1,162	$5,176	$6,174

Pollution Control Equipment in Use at the Source: The presence of existing pollution control technology at Sundt Unit 4 is reflected in the consideration of available control technologies and in the development of baseline emission rates for use in cost calculations and visibility modeling. In the case of NO_x, current pollution controls are reflected in our selection of 2011 as the baseline period, which includes the use of LNB and OFA.

Energy and Non-Air Quality Environmental Impacts: Regarding potential energy impacts of the BART control options, we note that SCR incurs a draft loss that will result in certain load loss, and that other emissions controls may also have modest energy impacts. The costs for direct energy impacts, i.e., power consumption from the control equipment and additional draft system fans from each control technology, are included in the cost analyses. Indirect energy impacts, such as the energy to produce raw materials, are not considered, which is consistent with the BART Guidelines. Ammonia adsorption (resulting from ammonia injection from SCR or SNCR) to fly ash is generally not desirable due to odor but does not impact the integrity of the use of fly ash in concrete. The ability to sell fly ash is unlikely to be affected by the installation of SNCR or SCR technologies. Finally, SNCR and SCR may involve potential safety hazards associated with the transportation and handling of anhydrous ammonia. However, since the handling of anhydrous ammonia will involve the development of a risk management plan (RMP), we consider the associated safety issues to be manageable as long as established safety procedures are followed. As a result, we do not consider these impacts sufficient to warrant the elimination of either of the available control technologies.

Remaining Useful Life of the Source: We are considering the "remaining useful life" of Sundt Unit 4 as one element of the overall cost analysis as allowed by the BART Guidelines.[54] Since there is not state- or federally-enforceable shut-down date for this unit, we have used a 20-year amortization period per the EPA Cost Control Manual as the remaining useful life for the facility. [55]

Degree of Visibility Improvement: The visibility improvement due to NO_x controls is modest. SNCR was modeled at a 30 percent NO_x emission reduction. As shown in Table 9, this yields a maximum visibility improvement of just over 0.2 dv at Saguaro. Galiuro improves about half as much, and other areas much less. The cumulative improvement across all impacted Class I areas is 0.5 dv. SCR was modeled at 89 percent NO_x reduction to achieve 0.05 lb/MMBtu. SCR provides a maximum improvement of 0.8 dv, which occurs at Saguaro. Galiuro again improves about half as much, and the cumulative improvement across all Class I areas is 1.6 dv. This visibility improvement is substantially greater for SCR than for SNCR.

TABLE 9—SUNDT 4: VISIBILITY IMPACT AND IMPROVEMENT FROM NO_X CONTROLS

[54] 40 CFR Part 51, Appendix Y, section IV.D.4.k.

[55] We note that the 20 year amortization period is primarily used in NO_x control cost calculations, such as for SCR. In order to promote consistency in the analysis, we have used the 20 year period in the cost calculations for other control options, such as for SO_2 control, for which the Control Cost Manual includes examples that use an amortization period of 15 years.

Class I Area	Distance (km)	Visibility Impact	Visibility Improvement	
		Base Case	SNCR (ctrl04)	SCR (ctrl08)
Chiricahua NM	144	0.43	0.03	0.12
Chiricahua WA	141	0.51	0.05	0.15
Galiuro WA	64	1.10	0.12	0.34
Gila WA	232	0.17	0.02	0.04
Mazatzal WA	203	0.19	0.02	0.04
Mount Baldy WA	232	0.15	0.01	0.03
Pine Mountain WA	247	0.15	0.02	0.03
Saguaro NP	17	3.40	0.23	0.78
Sierra Ancha WA	178	0.19	0.01	0.04
Superstition WA	137	0.32	0.01	0.05
Cumulative (sum)		6.6	0.5	1.6
Maximum		3.40	0.23	0.78
# CIAs >= 0.5 dv		3	0	1
million $/dv (cumul. dv)			$2.4	$3.7
million $/dv (max. dv)			$5.5	$7.7

c. Proposed BART Determination for NO_x

EPA proposes to find that BART for NO_x is an emission limit of 0.36 lb/MMBtu on a 30-day BOD rolling basis that is achievable by SNCR with LNB and OFA. The primary factors supporting this proposed finding are the average cost-effectiveness and anticipated visibility benefits of controls. In particular, while SCR is anticipated to achieve the greatest degree of visibility improvement, it is also significantly more expensive than SNCR, with an average cost-effectiveness of $5176/ton. We do not consider this average cost to be warranted by the projected visibility benefit of SCR for this facility. Table 10 provides a summary of our five-factor BART analysis.

In proposing an emission limit of 0.36 lb/MMBtu, we have considered the annual average design value for SNCR of 0.31 lb/MMBtu as well as the need to account for emissions associated with startup and shutdown events. To account for this variability, we have examined the difference between the highest 30-day rolling NO_x value and the highest annual average NO_x value observed over the baseline period, which is approximately 17 percent.[56] We have applied this variability to the annual average design value to develop a 30-day BOD rolling emission limit, which we consider to provide sufficient margin for a limit that will apply at all times.

We propose to require compliance with this requirement within three years of the effective date of the final rule. A 2006 Institute of Clean Air Companies (ICAC) study indicated that the installation time for a typical SNCR retrofit, from bid to startup, is 10 to 13 months.[57] However, because we are also requiring the installation of additional SO_2 controls, we consider a three year period for compliance with both BART determinations to be appropriate. We are seeking comment on whether this compliance date is reasonable and consistent with the requirement of the Clean Air Act that BART be installed "as expeditiously as practicable but in no event later than five years after [promulgation of the applicable FIP]."[58] If we receive information during the comment period that establishes that a different compliance time frame is appropriate, we may finalize a different compliance date. Finally, we are proposing regulatory text that includes monitoring, reporting, and recordkeeping requirements to ensure that the emission limit and compliance deadline are enforceable. As part of the proposed monitoring requirements, we are including a requirement to monitor rates of ammonia injection in order to ensure proper operation of the SNCR in a manner that minimizes ammonia emissions.

TABLE 10—SUNDT 4: SUMMARY OF BART ANALYSIS FOR NO_X

Sundt Unit 4 (130 MW)	LNB+ OFA (baseline)	SNCR+ LNB	SCR+LNB
Emissions			
Emission Factor (lb/MMBtu)	0.445	0.312	0.050

[56] See spreadsheet "Sundt4 2001-12 Emission Calcs 2014-01-24.xlsx" in the docket.
[57] See "Typical Installation Timelines for NO_x Emissions Control Technologies on Industrial Sources", Institute of Clean Air Companies, December 4, 2006.
[58] Clean Air Act section 169A(g)(4), 42 U.S.C. 7491(g)(4).

Emission Rate (tpy)	1310	917	147
Emission Reduction (tpy)	--	393	1,162
Control Effectiveness (%)	--	30%	89%
Costs of Compliance			
Capital Cost ($)	--	$3,079,089	$45,167,561
Annualized Capital Cost ($)	--	$290,644	$4,263,498
Annual O&M ($)	--	$975,124	$1,753,975
Total Annual Cost ($)	--	$1,265,768	$6,017,474
Ave Cost-Effectiveness ($/ton)	--	$3,222	$5,176
Incremental Cost-Effectiveness ($/ton)	--	--	$6,174
Pollution Control Equipment in Use			
Low-NO_x Burners and Over Fire Air			
Energy and Non-Air Quality Environmental Impacts			
Energy impacts have been reflected in annual O&M costs in the costs of compliance			
SCR and SNCR may create potential safety and environmental hazards from the transportation and handling of anhydrous ammonia. We consider these impacts manageable with the development of an RMP and additional safety procedures, and do not consider them sufficient enough to warrant eliminating either of these available control technologies.			
Remaining Useful Life			
Control technology amortization period	--	20 years	20 years
Visibility Improvement			
Single largest Class I area improvement (dv)	--	0.23	0.78
Single Class I area cost-effectiveness (million $/dv)	--	$5.5	$7.7
Class I areas with ≥ 0.50 dv improvement	--	0	1
Cumulative visibility improvement (dv)	--	0.5	1.6
Cumulative cost-effectiveness (million $/dv)	--	$2.4	$3.7

4. Proposed BART Analysis and Determination for SO_2

For our SO_2 BART analysis, we identified all available control technologies, eliminated options that are not technically feasible, and evaluated the control effectiveness of the remaining control options. We then evaluated each control in terms of a five-factor BART analysis and proposed a determination for BART.

a. Control Technology Availability, Technical Feasibility, and Effectiveness

EPA identified three available and technically feasible technologies to control SO_2 emissions from Sundt Unit 4. These technologies are lime or limestone-based wet flue gas desulfurization (wet FGD), lime spray dry absorber (SDA or dry FGD), and dry sorbent injection (DSI). While each of these control options has certain design concerns and constraints associated with their implementation, all three options are considered technically feasible.

Lime or limestone-based wet FGD: Wet scrubbing systems mix an alkaline reagent, such as hydrated lime or limestone, with water to generate scrubbing slurry that is used to remove SO_2 from the flue gas. The alkaline slurry is sprayed countercurrent to the flue gas, such as in a spray tower, or the flue gas may be bubbled through the alkaline slurry as in a jet bubbling reactor. As the alkaline slurry contacts the exhaust stream, it reacts with the SO_2 in the flue gas. Design variations may include changes to increase the alkalinity of the scrubber slurry, increase slurry/ SO_2 contact, and minimize scaling and equipment problems. Insoluble calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) salts are formed in the chemical reaction that occurs in the scrubber, and exit as part of the scrubber slurry. The salts are eventually removed and handled as a solid waste byproduct. The waste byproduct is mainly $CaSO_3$, which is difficult to dewater. Solid waste byproducts from wet lime scrubbing are typically managed in dewatering ponds and landfills.

Design concerns associated with wet FGD involve the substantial water usage requirements needed to generate the alkaline reagent slurry as well as the substantial amount of wastewater and solid waste discharge associated with the spent byproduct. A wet FGD control system must be located after the fabric filter baghouse because the moist plume resulting from the wet scrubber system would create baghouse plugging issues if the control is placed ahead of the baghouse. In addition, a substantial footprint is required for the management of these waste products as well as for the absorber tower and associated process equipment such as the slurry preparation, mixing, associated tanks, and dewatering activities. While these design concerns do present some challenges, they do not warrant elimination of this option as technically infeasible.[59]

Our contractor has estimated that newly constructed wet FGD systems could achieve design emission rates (annual average basis) of 0.06 lb/MMBtu. Relative to baseline SO_2 emission rates, this corresponds to a control efficiency of 92 percent. We recognize that FGD systems are designed to achieve more stringent emission rates, and have demonstrated an ability to achieve control efficiencies up to 98 percent. Our contractor's report notes that the lower control efficiency cited here is regarded as a conservative estimate. While this is not the most stringent level of control that the technology is capable of achieving, we consider 92 percent control efficiency to be consistent with the median values reported for wet FGD systems.

Lime SDA or dry FGD: A spray dryer absorber uses a stream of either dry lime or hydrated lime (semi-dry) in a reaction tower where it reacts with SO_2 in the flue gas to form calcium sulfite solids. Unlike wet FGD systems that produce a slurry by-product that is collected separately from the fly ash, dry FGD systems are designed to produce a dry byproduct that must be removed with the fly ash in the particulate control equipment. As a result, dry FGD systems must be located upstream of the particulate control device to remove the reaction products and excess reactant material. In instances where hydrated lime is used as a reagent, the reaction towers must be designed to provide adequate contact and residence time between the exhaust gas and the slurry to produce a relatively dry byproduct. Typical process equipment associated with a spray dryer typically includes an alkaline storage tank, mixing and feed tanks, an atomizer, spray chamber, particulate control device and a recycle system. The recycle system collects solid reaction products and recycles them back to the spray dryer feed system to reduce alkaline sorbent use.

[59] TEP's review does not eliminate consideration of wet FGD, but does describe several design challenges that TEP notes should be reflected in the five factor analysis. We have incorporated certain elements of TEP's review in our analysis, as discussed in Step 4.

A design concern associated with a dry FGD system is that it must be installed prior to the fabric filter baghouse in order for the reagent to be captured and recycled. As noted in our contractor's report, the location of the existing fabric filter baghouse does not present enough space to install a new absorber between the boiler and the existing baghouse. As a result, a dry FGD at Sundt Unit 4 is assumed to include a new baghouse, which is reflected in the costs of compliance for the five-factor analysis. We consider this control option to be technically feasible.

Our contractor has estimated that newly constructed dry FGD systems could achieve design emission rate (annual average basis) of 0.08 lb/MMBtu. Relative to baseline SO_2 emission rates, this corresponds to a control efficiency of 89 percent. As noted for wet FGD systems, this is a conservative estimate of what dry FGD systems can achieve, and is consistent with the median values reported for dry FGD systems.

Dry Sorbent Injection: DSI involves the injection of powdered absorbent directly into the flue gas exhaust stream. These are simple systems that generally require a sorbent storage tank, feeding mechanism, transfer line and blower, and an injection device. The dry sorbent is typically injected countercurrent to the gas flow. An expansion chamber is often located downstream of the injection point to increase residence time and efficiency. Particulates generated in the reaction are controlled in the system's particulate control device. DSI requires less capital equipment, less physical space, and less modification to existing ductwork compared to a dry FGD system. However, reagent costs are much higher and, depending upon the absorbent and amount of sorbent injected, control efficiency is lower when compared to a dry FGD system. Soda ash and Trona (sodium sesquicarbonate) are potential options for reagent use. An important design consideration of DSI is the ability of the downstream particulate control device to accommodate the additional particulate loading resulting from the addition of the DSI reagent into the boiler flue gas. More effective particulate control devices allow for higher rates of sorbent injection, which in turn allow for more effective SO_2 control.

In a review of SO_2 control options for BART eligible units, the Northeast States for Coordinated Air Use Management (NESCAUM) estimated control effectiveness for DSI in a range of 40-60 percent.[60] More recently, as part of work done as part of the Integrated Planning Model (IPM), EPA has estimated control effectiveness as high as 80 percent,[61] depending upon factors such as the type of sorbent, the quantity of sorbent used, and the type of particulate control device employed. Generally, the use of more effective particulate control devices allow for higher rates of sorbent injection, and therefore greater DSI effectiveness. Since Sundt Unit 4 operates with a fabric filter, we consider a control effectiveness value in the upper range appropriate, and have used 70 percent control effectiveness in our calculations. This value is above the range indicated in the NESCAUM study, but does not require the high sorbent injection rates required to achieve the upper range of control indicated in IPM documentation. A summary of the control technologies and their associated control effectiveness is presented in Table 11.

TABLE 11—SUNDT 4: SO_2 CONTROL OPTIONS

Control Option	Control Effectiveness
Dry Sorbent Injection	70%
Dry FGD or Lime SDA	89%
Wet FGD (lime- or limestone-based)	92%

b. BART Analysis for SO_2

Costs of Compliance: Our consideration of the costs of compliance focuses primarily on the cost-effectiveness of each control option, as measured in cost per ton and incremental cost

[60] "Assessment of Control Technology Options for BART-Eligible Sources", Northeast States for Coordinated Air Use Management In Partnership with The Mid-Atlantic/Northeast Visibility Union, March 2005.
[61] IPM Model – Revisions to Cost and Performance for APC Technologies, Dry Sorbent Injection Cost Development Methodology, August 2010.

per ton. The emissions estimates and cost-effectiveness for the three control options are shown in Table 12 and Table 13, respectively. Both wet and dry FGD have average cost-effectiveness values over $5,000/ton, much greater than DSI, which is a control option that we consider very cost-effective at $1,857/ton. Moreover, both wet and dry FGD have very high incremental cost-effectiveness values, indicating that while they are more effective than less stringent control options, this additional degree of effectiveness comes at a substantial cost.

In evaluating the costs of compliance for the control options, we have calculated the control costs ($) and emission reductions (tons/year of pollutant) for each control technology, developed average cost-effectiveness ($/ton) values, and arrived at the emission reductions for each option as summarized Table 12. A more detailed version of emission calculations is in our docket,[62] and in our contractor's report. As noted previously in our NO_x BART analysis, the heat duty and capacity factor used in these calculations differ from the values used in the calculations originally prepared by our contractor because the maximum gross capacity of Sundt Unit 4 while burning coal is about 130 MW, compared to its natural-gas nameplate capacity of 173 MW. The heat duty (MMBtu/hr) and capacity factor used in Table 12 reflect the coal-burning nameplate capacity.[63] Detailed cost calculations presented in Table 13 are in the docket.[64]

TABLE 12—SUNDT 4: SO_2 CONTROL OPTION EMISSION ESTIMATES

Control Option	Control Efficiency (%)	Emission Factor (lb/MMBtu)	Heat Duty (MMBtu/hr)	Capacity Factor	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (tpy)	SO_2 Emission Reduction (tpy)
Baseline (no control)	--	0.729	1,371	0.49	1,000	2,145	--
DSI	70%	0.219	1,371	0.49	300	644	1,502
DFGD	89%	0.080	1,371	0.49	110	236	1,909
WFGD	92%	0.060	1,371	0.49	82	177	1,969

[62] See spreadsheet "Sundt4 2001-12 Emission Calcs 2014-01-24.xlsx" in the docket.
[63] As noted by TEP and Burns and McDonnell, although the calculated capacity factor is different, the annual emissions in tons per year removed do not change significantly, as the change in capacity factor is largely offset by the change in maximum unit gross rating.
[64] See spreadsheet "Sundt4 Control Costs 2014-01-26.xlsx" in the docket.

TABLE 13—SUNDT 4: SO_2 CONTROL OPTION COST-EFFECTIVENESS

Control Option	Capital Cost ($)	Annualized Capital Cost ($)	Annual Operating Cost ($)	Total Annual Cost ($/yr)	Emission Reduction (tpy)	Cost-Effectiveness ($/ton)	
						Ave	Incremental
DSI	$3,250,000	$306,777	$2,482,107	$2,788,884	1,502	$1,857	--
DFGD	$72,470,559	$6,840,708	$2,880,841	$9,721,549	1,909	$5,091	$17,007
WFGD	$80,629,663	$7,610,870	$3,227,467	$10,838,337	1,969	$5,505	$18,795

Pollution Control Equipment in use at Source: In the case of SO_2, Sundt Unit 4 does not operate with any existing control technology. This is reflected in our selection of calendar year 2011 as the baseline period, which represents uncontrolled coal-fired emissions.

Energy and Non-Air Quality Environmental Impacts: For wet FGD, energy impacts include certain auxiliary power requirements that are necessary to operate the wet FGD system and to potentially compensate for pressure head loss through the scrubber. These energy impacts are reflected as auxiliary power costs in the cost of compliance estimates. Non-air quality environmental impacts include water usage requirements and the storage and disposal of wet ash. Wet FGD requires very large quantities of water to ensure proper control effectiveness. Securing such quantities of water is a significant challenge in more arid regions of the country such as Arizona, and would preclude the use of that water for potentially more beneficial uses. The on-site storage and disposal of wet ash in large retention ponds triggers significant additional regulatory requirements, as it represents a substantial water pollution threat.

For dry FGD, the energy and non-air environmental impacts are similar to those for wet FGD. Operation of a dry FGD system still requires securing significant supplies of water, although to a lesser degree than wet FGD systems. In addition, dry FGD systems will result in generation of larger quantities of boiler ash, and has the potential to affect negatively the properties and quality of boiler ash. In some instances, boiler ash that is suitable to sell for beneficial purposes may no longer be marketable following installation of a dry FGD system. Energy impacts also include auxiliary power requirements for operation of the dry FGD system, and for overcoming pressure head loss through the scrubber. While we note certain potential impacts resulting from the water resource requirements associated with wet FGD as well as the additional solid waste generation associated with wet and dry FGD, we do not consider these impacts sufficient enough to warrant eliminating these control technologies.

DSI could potentially have an adverse effect on the quality of the boiler fly ash, which would make it unmarketable for beneficial uses. Use of DSI also results in an ash byproduct which would require landfill disposal, thereby increasing solid waste generation rates at the plant. Energy impacts are limited to auxiliary power requirements for operation of the DSI system. We do not consider these impacts sufficient enough to warrant eliminating this control technology.

Remaining Useful Life of the Source: We are considering the remaining useful life of Sundt Unit 4 as one element of the overall cost analysis as allowed by the BART Guidelines. Since we are not aware of any federally- or State-enforceable shut down date for Sundt Unit 4, we have used a 20-year amortization period described in the EPA Cost Control Manual as the remaining useful life for the control options considered for Unit 4. We note that the remaining useful life of the source is reflected in the evaluation of cost of compliance through the use of a 20-year amortization period in control cost calculations.

Degree of Visibility Improvement: The visibility improvement due to SO_2 controls is modest. As shown in Table 14, control via DSI, with a 70 percent SO_2 emissions reduction, gives a maximum visibility improvement of 0.2 dv, which occurs at Saguaro. Three other areas improve about half as much, and the cumulative improvement is 0.8 dv. Emissions controls via dry and wet FGD were modeled at 89 percent and 92 percent SO_2 emissions reduction, respectively. Both dry and wet FGD would cause a visibility disbenefit at Saguaro as indicated by the negative improvements in Table 14. The disbenefit is mainly due to the decreased stack exit temperature and exit velocity associated with these technologies, and more so for wet FGD than for dry FGD. These stack decreases result in less plume rise and increased impacts nearby. At areas farther away, the disbenefit is outweighed by the benefit of SO_2 reductions from FGD. This issue is discussed further in the TSD. With FGD, the maximum benefit occurs not at Saguaro, but at Galiuro, with 0.2 dv for dry FGD and 0.1 dv for wet FGD. The corresponding cumulative improvements are 0.6 dv and 0.4 dv for dry and wet FGD, respectively, including the areas of disbenefit. All these improvements are substantially lower than those from DSI, and the visibility cost-effectiveness of each FGD is more than quadruple that of DSI. EPA finds that the improvement from DSI is substantial enough to support its selection as BART, and that it is clearly a better choice than dry FGD and wet FGD.

TABLE 14—SUNDT 4: VISIBILITY IMPACT AND IMPROVEMENT FROM SO_2 CONTROLS

Class I Area	Distance (km)	Visibility Impact	Visibility Improvement		
		Base Case	DSI 70% (ctrl14)	Dry FGD (ctrl02)	Wet FGD (ctrl03)
Chiricahua NM	144	0.43	0.05	0.07	0.06
Chiricahua Wild.	141	0.51	0.10	0.10	0.11
Galiuro Wild.	64	1.10	0.10	0.16	0.09
Gila Wild.	232	0.17	0.04	0.05	0.05
Mazatzal Wild.	203	0.19	0.07	0.08	0.09
Mount Baldy Wild.	232	0.15	0.05	0.05	0.06
Pine Mountain Wild.	247	0.15	0.05	0.06	0.06
Saguaro NP	17	3.40	0.20	-0.16	-0.27
Sierra Ancha Wild.	178	0.19	0.06	0.08	0.08
Superstition Wild.	137	0.32	0.09	0.10	0.10
Cumulative (sum)		6.6	0.8	0.6	0.4
Maximum		3.40	0.20	0.16	0.11
# CIAs >= 0.5 dv		3	0	0	0

million $/dv (cumul. dv)			$3.5	$16.4	$25.1
million $/dv (max. dv)			$14	$60	$97

c. BART Determination for SO_2

EPA proposes an emission limit of 0.23 lb/MMBtu on a 30-day (BOD) rolling basis as BART to control SO_2 from Sundt Unit 4. This emission limit, equivalent to using DSI, is considered very cost-effective at $1,857/ton. In evaluating the appropriate emission limit for DSI, we have considered the annual average design value for DSI of 0.21 lb/MMBtu as well as the need to account for emissions associated with startup and shutdown events. To determine how to account for this variability, we have examined the difference between the highest 30-day rolling SO_2 value and the highest annual average SO_2 value observed over the baseline period, which is approximately 9 percent.[65] We have applied this variability to the annual average design value to develop a 30-day BOD rolling emission limit, which we consider a sufficient margin for a limit that will apply at all times. Please refer to Table 15 that provides a summary of our five-factor BART analysis.

We propose to require compliance with this requirement within three years of the effective date of the final rule. However, we are seeking comment on whether this compliance date is reasonable and consistent with the requirement of the Clean Air Act that BART be installed "as expeditiously as practicable but in no event later than five years after [promulgation of the applicable FIP]."[66] If we receive information during the comment period that establishes that a different compliance time frame is appropriate, we may finalize a different compliance date. We are also proposing regulatory text that includes monitoring, reporting, and recordkeeping requirements associated with this emission limit.

TABLE 15—SUNDT 4: SUMMARY OF BART ANALYSIS FOR SO_2

[65] See spreadsheet "Sundt4 2001-12 Emission Calcs 2014-01-24.xlsx" in the docket.
[66] Clean Air Act section 169A(g)(4), 42 U.S.C. 7491(g)(4).

Sundt Unit 4 (130 MW)	Baseline	DSI	Dry FGD	Wet FGD
Emission Factor (lb/MMBtu)	0.729	0.219	0.08	0.06
Emission Rate (tpy)	2145	644	236	177
Emission Reduction (tpy)	--	1,502	1,909	1,969
Control Effectiveness	--	70%	89%	92%
Cost of Compliance				
Capital Cost ($)	--	$3,250,000	$72,470,559	$80,629,663
Annualized Capital Cost ($)	--	$306,777	$6,840,708	$7,610,870
Annual O&M ($)	--	$2,482,107	$2,880,841	$3,227,467
Total Annual Cost ($)	--	$2,788,884	$9,721,549	$10,838,337
Ave CE ($/ton)	--	$1,857	$5,091	$5,505
Incremental CE ($/ton)	--	--	$23,081	$18,795
Pollution Control Equipment in Use at Source				
There is no existing control technology for SO_2				
Energy and Non-Air Quality Environmental Impacts				
Energy impacts are reflected in annual O&M costs in the costs of compliance.				
Wet ash from wet and dry FGD represents a substantial water pollution threat.				
Water resources for wet and dry FGD may preclude more beneficial uses of water.				
Remaining Useful Life				
Control technology amortization period	--	20 years	20 years	20 years
Visibility Improvement				
Single largest Class I area improvement (dv)	--	0.20	0.16	0.11
Single Class I area cost-effectiveness (million $/dv)	--	$14.3	$60.4	$96.8
Class I areas with ≥ 0.50 dv improvement	--	0	0	0
Cumulative visibility improvement (dv)	--	0.8	0.6	0.4
Cumulative cost-effectiveness (million $/dv)	--	$3.5	$16.4	$25.1

3. Proposed BART Analysis and Determination for PM_{10}

a. Control Technology Availability, Technical Feasibility, and Effectiveness

Sundt Unit 4 currently operates with a fabric filter baghouse for particulate control, which is considered the most stringent control device for particulate matter. These devices operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag that is designed and manufactured to trap particles greater than a certain specified diameter. As the air passes through the fabric, the dust accumulates on the cloth and is removed from the air stream. The accumulated dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric has the potential to result in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter.

b. BART Analysis for PM_{10}

The BART Guidelines provide that, where a source has controls already in place that are the most stringent controls available, it is not necessary to complete comprehensively a full five-factor BART analysis, as long the most stringent controls available are made federally enforceable. Therefore, instead of completing the remaining steps of a five-factor BART analysis, we have evaluated the appropriate level of emissions to ensure that the fabric filter achieves an appropriate degree of control.

c. Proposed BART Determination for PM_{10}

EPA is proposing a filterable PM_{10} BART emission limit of 0.03 lb/MMBtu based on the use of the existing fabric filter baghouse currently in operation, which is the most stringent control for particulate matter. We note that Mercury and Air Toxics (MATS) Rule establishes an emission standard of 0.03 lb/MMBtu filterable PM (as a surrogate for toxic non-mercury metals) as representing Maximum Achievable Control Technology (MACT) for coal-fired EGUs.[67] This standard derives from the average emission limitation achieved by the best performing 12 percent of existing coal-fired EGUs, as based upon test data used in developing the MATS Rule.[68] The BART Guidelines provide that, “unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, you may

[67] 77 FR 9304, 9450, 9458 (February 16, 2012) (codified at 40 CFR 60.42Da(a), 60.50Da(b)(1)).
[68] See Memorandum from Jeffrey Cole (RTI International) to Bill Maxwell (EPA) regarding “National Emission Standards for Hazardous Air Pollutants (NESHAP) Maximum Achievable Control Technology (MACT) Floor Analysis for Coal- and Oil-fired Electric Utility Steam Generating Units for Final Rule” (December 16, 2011).

rely on the MACT standards for purposes of BART."[69] Therefore, we propose to find that 0.03 lb/MMBtu filterable PM_{10} is an appropriate limit for BART at Sundt Unit 4.

4. Better than BART Alternative

We are proposing a switch to natural gas on Sundt Unit 4 as a better-than-BART alternative to the emissions controls previously proposed in this section for a coal-fired unit. Unit 4 was originally constructed as a natural gas-fired boiler, and has used natural gas as a primary fuel for significant periods of time since 2009. While a change in fuel supply to natural gas instead of coal is an inherently less polluting option, the BART Guidelines do not require the consideration of fuel supply changes as a control option.[70] As a result, the option of burning only natural gas is not considered in our BART analysis. However, TEP has submitted to EPA an alternative to BART based on the elimination of coal as a fuel source for Sundt Unit 4 by December 31, 2017. As part of this submittal, TEP compared the potential emission reductions and visibility benefit between a natural gas fuel change and certain combinations of NO_x and SO_2 controls.[71]

EPA has evaluated this alternative proposal pursuant to the "better-than-BART" provisions of the RHR. In particular, the RHR allows for implementation of "an emissions trading program or other alternative measure" in lieu of BART if the alternative measure achieves greater reasonable progress than would be achieved through the installation and operation of BART.[72] The rule further states that "[i]f the distribution of emissions is not substantially different than under BART, and the alternative measure results in greater emissions reductions, than the alternative measures may be deemed to achieve greater reasonable

[69] 40 CFR Part 51, Appendix Y, Section IV.C.
[70] 40 CFR 51, Appendix Y, Section IV.D.1.5, "STEP 1: How do I identify all available retrofit emission control techniques?"
[71] Letter dated November 1, 2013.
[72] 40 CFR 51.308(e)(2).

progress".[73] Because the emissions reductions under EPA's BART proposal for Sundt Unit 4 and the reductions from TEP's proposed alternative would occur at the same facility, the distribution of emissions under BART and the alternative are not substantially different. Therefore, if the alternative emission control strategy results in greater emissions reductions than our BART proposal, EPA may deem the alternative emission control strategy to achieve greater reasonable progress. A comparison of annual emission estimates between the BART determination and alternative to BART is summarized in Table 16. BART determination annual emissions are based upon the annual average emission factors and annual capacity factor used in our BART analysis, consistent with coal usage. For the alternative to BART, annual emissions are based on a combination of historical natural gas usage data as indicated in TEP's submittal, as well as standard emission factors for natural gas combustion. A more detailed discussion of emission estimates from these two scenarios is included in our TSD.

TABLE 16—SUNDT 4: COMPARISON OF BART DETERMINATION AND ALTERNATIVE TO BART

Parameters	Units	BART Determination	Natural Gas Fuel Switch	Difference
Heat Duty	MMBtu/hr	1,371	1,828	
Capacity Factor		0.49	0.37	
NO_x	Ctrl Tech	SNCR+LNB+OFA	LNB+OFA	
	lb/MMBtu[1]	0.31	0.22	
	tpy	917	652	265
Particulate Matter	Ctrl Tech	Fabric Filter	None	
	lb/MMBtu[1]	0.03	0.01	
	tpy	88	30	59
SO_2	Ctrl Tech	Dry Sorbent Injection	None	
	lb/MMBtu[1]	0.22	0.00064	
	tpy	644	1.9	642

[1] Annual average emission factors

[73] 40 CFR 51.308(e)(3).

As seen in Table 16, a change to natural gas usage achieves greater emission reductions than each of the individual BART determinations for NO_x, SO_2, and particulate matter, as well as in the aggregate. Although visibility modeling is not required to support a better-than-BART determination in this instance, EPA conducted modeling to verify the visibility benefits of the proposed alternative, as compared with EPA's BART determination. This modeling is described in the TSD and the results are summarized in Table 17.

TABLE 17—SUNDT 4: VISIBILITY IMPACT AND IMPROVEMENT FROM COMBINED SO_2 AND NO_X BART, AND FROM BETTER-THAN-BART ALTERNATIVE

Class I Area	Distance (km)	Visibility Impact	Visibility Improvement	
		Base Case	SNCR DSI 70% (ctrl15)	Natural Gas (ctrl13)
Chiricahua NM	144	0.43	0.09	0.19
Chiricahua WA	141	0.51	0.16	0.25
Galiuro WA	64	1.10	0.24	0.47
Gila WA	232	0.17	0.06	0.10
Mazatzal WA	203	0.19	0.08	0.12
Mount Baldy WA	232	0.15	0.06	0.09
Pine Mountain WA	247	0.15	0.06	0.09
Saguaro NP	17	3.40	0.49	1.06
Sierra Ancha WA	178	0.19	0.08	0.12
Superstition WA	137	0.32	0.11	0.19
Cumulative (sum)		6.6	1.4	2.7
Maximum		3.40	0.49	1.06
# CIAs >= 0.5 dv		3	0	1
million $/dv (cumul. dv)			$2.8	
million $/dv (max. dv)			$8.3	

Since Sundt is only 17 km from the eastern unit of Saguaro, its emitted NO_x may not be fully converted to NO_2 by the time it reaches there, as is assumed in the CALPUFF model. It thus may not be fully available to form visibility-degrading particulate nitrate. EPA explored this issue in CALPUFF sensitivity simulations described in the TSD. For EPA's proposed BART of SNCR plus DSI, the visibility improvement remains above 0.3 dv even when unrealistically low 10 percent NO-to-NO_2 conversion is assumed (i.e., no additional conversion of NO to NO_2 once the plume leaves the stack). The improvement from switching to natural gas remains above 0.7 dv at Saguaro. These results show that the FIP's proposed BART determination remains reasonable despite any concern over the NO conversion rate; the visibility improvement from BART remains substantial. The finding that natural gas provides better visibility improvement than the proposed BART determination also remains sound regardless of the NO conversion assumed.

Based on this information, we consider a natural gas fuel switch to result in greater emission reductions and achieve greater reasonable progress than the proposed BART determinations. Under this scenario, we are proposing a NO_x emission limit of 0.25 lb/MMBtu based on a 30-day BOD rolling average. As discussed previously in the NO_x BART determination, this represents about a 17 percent increase from the annual average emission rate of 0.22 lb/MMBtu, which we consider to provide sufficient margin for a limit that will apply at all times, including periods of startup and shutdown. In addition, we are proposing particulate matter and SO_2 emission limits consistent with natural gas use, as well as monitoring, reporting, and recordkeeping requirements.

B. Chemical Lime Nelson Plant Kilns 1 and 2

Summary: EPA is proposing to find that Chemical Lime Nelson is subject to BART. EPA is proposing BART emission limits for NO_x, SO_2 and PM_{10} for Kilns 1 and 2 at the Nelson Plant as listed in Table 18 and described in this section.

TABLE 18—NELSON LIME PLANT: SUMMARY OF PROPOSED BART DETERMINATIONS

Source	Pollutant	Emission	Control Technology*

		Limit (lb/ton feed)	(for reference only)
Kiln 1	NO_x	3.80	Selective Non-Catalytic Reduction (SNCR)
	SO_2	9.32	Lower sulfur fuel
	PM_{10}	0.12	Fabric filter baghouse (existing)
Kiln 2	NO_x	2.61	Selective Non-Catalytic Reduction (SNCR)
	SO_2	9.73	Lower sulfur fuel
	PM_{10}	0.12	Fabric filter baghouse (existing)

*The facility is not required to install the listed technology to meet the BART limit.

Affected Class I Areas: Nine Class I areas are within 300 km of the Nelson Lime Plant. Their nearest borders range from 24 km to 289 km away, with the Grand Canyon the closest and other areas more than 100 km away. The highest baseline visibility impact from the Nelson Plant is 1.79 dv at Grand Canyon NP followed by 0.31 at Sycamore Canyon WA and 0.28 at Zion NP. The cumulative sum of visibility impacts over all the Class I areas is 3.34 dv.

Facility Overview: The Nelson Plant processes limestone and manufactures lime near Peach Springs in Yavapai County, Arizona. The limestone processing plant consists of a quarry mining operation, a limestone crushing and screening operation, a limestone kiln feed system, a solid fuel handling system, two rotary lime kilns, front and back lime handling systems, a lime hydrator, diesel electric generators, fuel storage tanks, and other support operations and equipment. The lime manufacturing equipment consists of two lime rotary kilns (Kiln 1 and Kiln 2) and auxiliary equipment necessary for receiving crushed limestone, processing it through the lime kilns, and processing the lime kiln product. The lime kilns are used to convert crushed limestone ($CaCO_3$) into quicklime (CaO).

We primarily relied on four sources of information for our proposed BART analyses and determinations. An initial BART analysis performed by our contractor[74] is available in the docket in the form of a final contractor's report and associated modeling spreadsheets. We also

[74] Technical Analysis for Arizona and Hawaii Regional Haze FIPs: Task 7: Five-Factor BART Analysis for Chemical Lime Company Nelson, TEP Sundt (Irvington), and Catalyst Paper (Snowflake) Plants, Contract No. EP-D-07-102, Work Assignment 5-12; Prepared for EPA Region 9 by University of North Carolina at Chapel Hill, ICF International, and Andover Technology Partners; October 9, 2012.

incorporated elements of a five-factor BART analysis[75] provided by Lhoist North America (LNA) of Arizona, owner of the Nelson Plant, that includes control cost estimates and visibility modeling. Another key document in our analysis is the Nelson Lime Plant's Title V Operating Permit.[76]

Baseline Emissions Calculations: LNA's approach to establishing baseline emissions was to first establish baseline emission factors in lb/ton lime based on CEMS testing performed from March to June 2013. Annual average baseline emissions were calculated by multiplying these lb/ton emission factors by the highest annual lime production rate observed over a period from 2001 to 2012. Maximum daily emissions were calculated by multiplying lb/ton emission factors by the maximum daily lime production rate observed during the March to June 2013 testing period. As explained in further detail in our TSD, we consider LNA's general approach appropriate, but also note that it represents a conservatively high estimate of baseline emissions, and potentially overstates the anticipated emission reductions and visibility benefit from the evaluated control options. Nonetheless, given the lack of measured annual emissions data, we concur with LNA's use of a conservatively high baseline emissions estimate and we have incorporated this estimate into our analysis. The baseline daily and annual emission rates and associated production levels are shown in Table 19.

TABLE 19—NELSON LIME PLANT: SUMMARY OF MAXIMUM DAILY AND ANNUAL BASELINE EMISSIONS FOR NO_X AND SO_2

Kiln	Lime Production			NO_x			SO_2		
	Max Daily[2]	Max Annual	Year	Emission Factor[1]	Maximum Emissions		Emission Factor[1]	Maximum Emissions	
	(tpd)	(tpy)		(lb/ton lime)	(lb/day)	(tpy)	(lb/ton lime)	(lb/day)	(tpy)
Kiln 1	866	258,508[3]	2010	7.59	6,573	981	12.15	10,522	1,570

[75] *BART Five Factor Analysis, Lhoist North America Nelson Lime Plant*; Prepared by Trinity Consultants in Conjunction with Lhoist North America of Arizona, Inc.; Project 131701.0061; August 2013. (Public version dated September 27, 2013).

[76] Title V Operating Permit and Technical Support Document for the Nelson Lime Plant, Permit # 42782, Issued August 8, 2011 by the Arizona Department of Environmental Quality.

Kiln 2	1,246	378,296[4]	2012	5.21	6,492	985	12.69	15,812	2,400

[1] Maximum emission factors observed during March, May and June 2013 CEMS testing.

[2] Maximum daily rates occurring during the March 2013 CEMS testing.

[3] 2010, [4]2012

1. Proposed Subject to BART

As part of our July 30, 2013 final rulemaking on the Arizona RH SIP, we approved ADEQ's finding that Chemical Lime Nelson Plant (Nelson Lime Plant) Kilns 1 and 2 were BART-eligible, but disapproved ADEQ's determination that the Nelson Lime Plant was not subject to BART.[77] In light of this disapproval, we have conducted our own evaluation of whether Nelson Lime Plant is subject to BART, relying primarily on emissions data and modeling results provided by the facility's owner, LNA.[78]

As explained in the TSD, the baseline emissions estimates and the corresponding modeling results provided by LNA are conservative (i.e., tending to overestimate rather than underestimate the impacts, in this case). Nonetheless, we consider these results to be appropriate for purposes of a subject-to-BART determination, as well as for the five-factor BART analysis. LNA's modeling results indicate that the 98th percentile impact for each of the 3 years modeled is well over 0.5 dv at Grand Canyon National Park.[79] Therefore, we propose to determine that Nelson Lime Plant (Kilns 1 and 2) is subject to BART.

2. Proposed BART for NO_x

For our NO_x BART analysis, we identified all available control technologies, eliminated options that are not technically feasible, and evaluated the control effectiveness of the remaining

[77] 78 FR 46175 (codified at 40 CFR 52.145(g)(1)(i)).
[78] BART Five Factor Analysis, Lhoist North America Nelson Lime Plant; Prepared by Trinity Consultants in Conjunction with Lhoist North America of Arizona, Inc.; Project 131701.0061; August 13, 2013 (Public version dated September 27, 2013).
[79] *Id.*, Table 4-7. We note that the visibility modeling performed by LNA used only the annual average Class I area background concentrations, rather than the best 20 percent days background concentrations. The use of annual average generally results in lower visibility impacts than the best 20 percent days. Therefore, had LNA used the best 20 percent days, the baseline impacts would likely have been even greater.

control options. We then evaluated each control in terms of a five-factor BART analysis and made a determination for BART.

a. Control Technology Availability, Technical Feasibility and Effectiveness

EPA proposes to find that SNCR is the only technically feasible control option to control NO_x emissions with a control efficiency of 50 percent. In order to determine a reasonable performance standard for controlling NO_x emissions, we considered four available retrofit control technologies for NO_x on Kilns 1 and 2. These control technologies are a LNB, mixing air technology (MAT), SCR, and SNCR. After evaluating each of these technologies to eliminate technically infeasible options, we determined that SNCR is the only remaining technically feasible control option

Low-NO_x Burners: LNB are designed to reduce flame turbulence, delay fuel/air mixing, and establish fuel-rich zones for initial combustion. LNA indicated that it experimented with the installation of bluff body LNB on the Nelson Lime Plant kilns in 2001.[80] These LNB wore out in about six months, negatively affected production, caused brick damage, and resulted in unscheduled shutdowns of the kilns. We recognize that the staged combustion principle of LNB can present operational difficulties and potential product quality issues for lime production that are not exhibited in the cement industry. At this time we consider LNB to be technically infeasible for the Nelson Plant kilns, since we do not have any information to suggest otherwise at this time. The technical feasibility of LNB will be re-evaluated for lime kilns in subsequent reasonable progress planning periods.

Mixing Air Technology: MAT is the practice of injecting a high pressure air stream into the middle of a kiln to help mix the air flowing through the kiln. While the theory behind MAT suggests that the technology is effective at reducing NO_x emissions, it is not clear whether this

[80] Described on page 5-2, "*BART Five Factor Analysis, Lhoist North America Nelson Lime Plant*" (Public version dated September 27, 2013).

control technology is effective on lime kilns. We propose to eliminate MAT as not technically feasible for retrofit on Kiln 1 and Kiln 2.

Selective Catalytic Reduction: This process uses ammonia in the presence of a catalyst to selectively reduce NO_x emissions from exhaust gases. In SCR, ammonia, usually diluted with air or steam, is injected through a grid system into hot flue gases that are then passed through a catalyst bed to carry out NO_x reduction reactions. The catalyst is not consumed in the process but allows the reactions to occur at a lower temperature. However, SCR is subject to catalyst poisoning in high dust kiln exhausts. Therefore, SCR would have to be placed after the particulate control systems. According to LNA, given the operating temperature range for Kiln 1 and Kiln 2 at the Nelson Lime Plant, the SCR catalyst would need to be located prior to the kiln baghouses, which would result in poisoning or covering of the catalyst. In addition, there are no SCR systems currently operating on lime kilns. We propose to eliminate SCR as not technically feasible for retrofit on Kiln 1 and Kiln 2.

Selective Non-Catalytic Reduction: SNCR is a technically feasible option for reducing NO_x emissions from the Nelson Lime Plant kilns as shown in Table 20. This control technique relies on the reduction of NO_x in exhaust gases by injection of ammonia or urea, without using any catalyst. This approach avoids the problems related to catalyst fouling and poisoning attributed to SCR, but requires injection of the reagents in the kiln at a temperature between 1600°F to 2000°F. Because no catalyst is used to increase the reaction rate, the temperature window is critical for conducting this reaction. LNA has not conducted any detailed design work for an SNCR system for the Nelson Plant kilns, but anticipates that a 50 percent reduction is achievable based on LNA's experience with operating a urea-injection system at another LNA lime plant.

TABLE 20—NELSON LIME PLANT: SNCR CONTROL EFFICIENCY FOR BASELINE EMISSIONS

Control Option	Control Efficiency	Emission Factor	Maximum Emission Rate		Emissions Removed
	(%)	(lb/ton lime)	(lb/day)	(tpy)	(tpy)
Kiln 1					
Baseline	--	7.59	6,573	981	--
SNCR	50%	3.80	3,286	491	491
Kiln 2					
Baseline	--	5.21	6,492	985	--
SNCR	50%	2.61	3,246	493	493

b. BART Analysis for NO_x

EPA conducted a five-factor BART analysis of SNCR to evaluate its cost-effectiveness and visibility benefit. This analysis indicates that SNCR is cost-effective and results in visibility improvement.

Cost of Compliance: The following table provides LNA's estimated cost for installation and operation of SNCR. Capital cost estimates developed by LNA relied primarily on vendor cost estimates and LNA's experience at other lime plants, with the remainder of the capital costs calculated using the cost methodology contained in EPA's Control Cost Manual. LNA has asserted a confidential business information (CBI) claim regarding certain annual operating costs such as reagent usage and auxiliary power costs. As a result, we have prepared our own independent estimate of annual operating costs based upon a combination of publicly available data and certain general assumptions as described in the Contractor's Report.[81] Table 21 is a summary of the estimated cost for installation and operation of SNCR.

TABLE 21—NELSON LIME PLANT: ESTIMATED COST FOR SNCR

Kiln	Capital Cost	Annualized Capital Cost	Annual Operating Cost	Total Annual Cost	Emission Reduction	Cost-Effectiveness
	($)	($)	($)	($/yr)	(tpy)	($/ton)
Kiln 1	$450,000	$42,477	$358,459	$400,936	491	$817

[81] Our estimate of annual operating costs is in the spreadsheet "Nelson Control Costs 2013-10-21.xlsx" in the docket.

Kiln 2	$450,000	$42,477	$354,981	$397,458	493	$807

Energy and Non-Air Quality Environmental Impacts: SNCR systems require electricity to operate the blowers and pumps, which will likely involve fuel combustion that will generate emissions. Overall, while the generation of the required electricity will result in emissions, the emissions should be low compared to the reduction in NO_x that would be gained by operating an SNCR system. The operation of SNCR systems on Kiln 1 and Kiln 2 would require that either urea or ammonia be stored on site. The storage of the chemicals does not result in a direct non-air quality impact. However, the potential for the urea or ammonia that would be stored to leak or otherwise be released from the storage vessels means there is the potential for both air and non-air quality related impacts. The storage of these chemicals does not significantly impact the BART determination.

Pollution Control Equipment in use at the Source: The presence of existing pollution control technology at each source is reflected in our BART analysis in two ways: first, in the consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling. Air pollution control equipment in use at the Nelson Lime Plant includes a number of baghouses, two multi-cyclone dust collectors, and a Ducon wet scrubber to control particulate matter emissions. The facility does not currently have control equipment for NO_x and SO_2. The kilns are allowed to burn coal, petroleum coke, fuel oil, or any combination of these fuels.

Remaining Useful Life of the Source: Since we are not aware of any enforceable shut-down date for the Nelson Lime Plant, we have used a 20-year amortization period, as noted in the EPA Cost Control Manual, as the remaining useful life of the kilns.

Degree of Visibility Improvement: LNA performed a visibility analysis[82] to assess the visibility improvement associated with SNCR. LNA performed dispersion modeling using the CALPUFF modeling system, which consists of the CALPUFF dispersion model, the CALMET meteorological data processor, and the CALPOST post-processing program. The specific program versions that were relied upon in the analysis match the program versions relied upon by EPA's contractor, the University of North Carolina at Chapel Hill and ICF International (UNC/ICF), in the BART analyses that they prepared for select sources, including the Nelson Plant. Most of the same data and parameter settings relied upon in the analysis are the same data and parameter settings that were relied upon in the contractor's report. Compared to the UNC work, LNA used updated higher base case SO_2 and NOx emissions, lower PM emissions, and lower stack exit velocities. LNA's analysis included tables of visibility impacts and the improvement from controls, including results for the individual model years 2001, 2002, and 2003, and it used visibility method "8a" and focused on the highest value from among the three years' 98th percentiles. In order to put all the facilities on the same footing, EPA post-processed the modeling files provided by LNA using the approach followed for the other facilities.

Table 22 represents the 98th percentile by the 22nd high over the 2001-2003 period using visibility method "8b." Using the EPA procedure, the maximum impact still occurs at the Grand Canyon, at 1.8 dv. The 98th percentile impacts at other Class I areas are about 0.3 dv or below, and the cumulative impact is 3.3 dv. The maximum visibility improvement due to SNCR is 0.58 dv, and cumulative improvement is 0.85 dv. There is little improvement at areas other than the Grand Canyon. These improvements yield a visibility cost-effectiveness of $1.4 million/dv using the maximum, and $0.9 million/dv using the cumulative improvement. These visibility improvements support the choice of SNCR as BART for NO_x.

[82] *BART Five Factor Analysis, Lhoist North America Nelson Lime Plant*, Trinity Consultants, August 2013.

TABLE 22—NELSON LIME PLANT: VISIBILITY IMPACT AND IMPROVEMENT FROM NO_X CONTROLS

Class I Area	Distance (km)	Visibility Impact	Visibility Improvement
		Base Case	SNCR (ctr1)
Bryce Canyon NP	235	0.20	0.06
Grand Canyon NP	24	1.79	0.58
Joshua Tree NP	238	0.23	0.02
Mazatzal WA	206	0.15	0.01
Pine Mountain WA	199	0.15	0.02
Sierra Ancha WA	289	0.11	0.01
Superstition WA	288	0.13	0.01
Sycamore Canyon WA	132	0.31	0.07
Zion NP	183	0.28	0.08
Cumulative (sum)		3.34	0.85
Maximum		1.79	0.58
# CIAs >= 0.5 dv		1	1
million $/dv (cumul. dv)			$0.9
million $/dv (max. dv)			$1.4

c. Proposed BART Determination for NO_x

We propose to find that BART for NOx for Kilns 1 and 2 is SNCR, and are proposing a BART emission limit for Kiln 1 of 3.80 lb/ton lime and for Kiln 2 of 2.61 lb/ton lime on a 30-day rolling basis, as demonstrated through the use of a CEMS. We consider SNCR to be a very cost-effective control option for Kilns 1 and 2, at $817/ton and $807/ton, respectively. In addition, we consider the anticipated visibility benefit from SNCR, 0.58 dv at Grand Canyon National Park and 0.85 cumulatively at all Class I areas within 300 km, to be substantial. In considering the other factors, we do not consider their impact substantial relative to the cost and visibility factors. We note that the remaining useful life of the source is reflected in the evaluation of cost of compliance through the use of a 20-year amortization period in control cost calculations. Since there is no existing NO_x control technology in use on the kilns, baseline emissions reflect uncontrolled NO_x emissions. In examining energy and non-air quality impacts, while we note certain impacts associated with SNCR, we do not consider these impacts sufficient to warrant its elimination as a control option.

We propose to require compliance with this requirement within three years after the effective date of the final rule. A 2006 Institute of Clean Air Companies (ICAC) study indicated that the installation time for a typical SNCR retrofit, from bid to startup-up, is 10-13 months.[83] In relation to other industrial sources, such as fossil fuel boilers, there are a limited number of examples of SNCR installation on lime kilns. Given this relative lack of information regarding SNCR installation schedules on lime kilns, we consider three years to be an appropriate length of time to design, install, and test an ammonia injection system for a lime kiln. In addition, we are also proposing regulatory text that includes monitoring, reporting, and recordkeeping requirements associated with this emission limit. As part of the proposed monitoring requirements, we are including a requirement to monitor rates of ammonia injection in order to ensure proper operation of the SNCR in a manner that minimizes ammonia emissions.

3. Proposed BART for SO_2

For our BART analysis, we identify all available control technologies, eliminate options that are not technically feasible, and evaluate the control effectiveness of the remaining control options. We then evaluate each control in terms of a five-factor BART analysis and make a determination for BART.

a. Control Technology Analysis for SO_2

EPA proposes to find that DSI and switching to lower sulfur fuel are technically feasible controls, while wet or semi-dry scrubbing is not technically feasible.

[83] See "Typical Installation Timelines for NO_x Emissions Control Technologies on Industrial Sources," Institute of Clean Air Companies, December 4, 2006.

Wet or Semi-Dry Scrubbing: We do not consider wet or dry scrubbing to be a feasible technology to control SO_2 emissions for this source. Wet scrubbing involves passing flue gas downstream from the main particulate matter control device through a sprayed aqueous suspension of lime or limestone that is contained in a scrubbing device. The SO_2 reacts with the scrubbing reagent to form lime sludge that is collected. The sludge usually is dewatered and disposed of at an offsite landfill. However, LNA has concluded, and we agree, that there is not sufficient water available for this type of system. According to LNA, two ground water wells supply about 106 gallons per minute (gpm) to the Nelson Plant, which currently uses about 80 gpm. Therefore, only 26 gpm of water is available for a scrubbing system that, even for a semi-dry scrubbing system that has lower water requirements than wet scrubbing, would require about 117 gpm. Moreover, a 1998 hydrologic report indicates that the prospects for developing additional wells, even low-yield wells, on the Nelson property are poor.[84] After reviewing the hydrologic report and the vendor estimate of water requirements for a semi-dry scrubber, we agree with this assessment.

Dry Sorbent Injection: DSI involves the injection of powdered absorbent directly into the flue gas exhaust stream. The sorbent reacts with SO_2 in the exhaust to form solid particles that are then removed by a particulate matter control device downstream of the sorbent injection. DSI is a simple system that generally requires a sorbent storage tank, feeding mechanism, transfer line and blower, and an injection device. DSI is generally considered technically feasible for the cement industry, although the level of control effectiveness may vary based upon site-specific conditions. We consider this option technically feasible for lime kilns. LNA has not included information in its analysis indicating that DSI would be infeasible for the Nelson Plant kilns.

[84] See "Results of Hydrogeologic Investigations for Development of Additional Water Supply, Chemical Lime Company, Nelson Plant, Yavapai County, AZ," July 8, 1998.

Lower Sulfur Fuel: The lower sulfur fuel option described by LNA involves changing the proportion of coal and petroleum coke used as a fuel blend. LNA currently uses a blend of 27 percent coal and 73 percent petroleum coke, on a mass basis, as the fuel for the kilns. Since coke has about four to five times more sulfur than coal, it is possible to decrease the sulfur in the fuel blend by increasing the proportion of coal. However, an increase in coal in the fuel blend will also increase the ash content of the fuel blend. Ash in the fuel can disrupt operations due to the buildup of ash rings in the kilns. A fuel blend with an ash content of about 6.5 percent or less must be used in order to avoid these operational challenges.

As noted in fuel usage and purchase records, the Nelson Plant currently operates on a coal and petroleum coke mixture. As a result, we consider adjusting the coal/coke ratio in the fuel mixture to be a technically feasible option. We note, however, that since the BART Guidelines do not require fuel supply changes to be considered as a control option, we have typically not considered changes in fuel in BART analyses.[85] However, because LNA included lower sulfur fuel in its analysis, we have retained it as a control option.

b. BART Analysis for SO_2

EPA conducted a five-factor BART analysis of the two technically feasible control options, DSI and lower sulfur fuel, to evaluate the cost-effectiveness and visibility benefit of each option along with any effect on the other factors.

Cost of Compliance: Our consideration of the cost of compliance focuses primarily on the cost-effectiveness of each control option as measured in cost per ton and incremental cost per ton. We estimate the SO_2 emissions rates for DSI and lower sulfur fuel as shown in Table 23, and the cost-effectiveness of these options as shown in Table 24. DSI has a control efficiency of 40 percent that results in about 1,588 tpy of SO_2 removed from both kilns. Lower sulfur fuel has a

[85] 40 CFR 51, Appendix Y, Section IV.D.1.5, “STEP 1: How do I identify all available retrofit emission control techniques?”

control efficiency of 23.3 percent that results in about 925 tpy of SO_2 removed from both kilns. Based on the total annual costs of controlling SO_2 emissions at both kilns, DSI would cost an average of about $4,200 per ton removed and lower sulfur fuel about $860 per ton removed. Since there is no existing SO_2 control technology in use in the plant, baseline emissions reflect uncontrolled SO_2 emissions.

While we consider it appropriate to use 40 percent control efficiency[86] for DSI, we are inviting comment on the control effectiveness of 23.3 percent for a lower sulfur fuel blend based on the ratio of coal (1.15 percent sulfur) to petroleum coke (5.64 percent sulfur). LNA estimates that the maximum coal-to-coke ratio to maintain overall fuel ash content below 6.5 percent is a 50 percent coal to 50 percent coke fuel mixture. A 50/50 mix corresponds to a fuel sulfur reduction of 1.13 percentage points, which represents a 23.3 percent reduction from the current fuel mixture. Based on a review of coal and coke properties along with historical fuel usage at the Nelson Plant, we agree with the use of a 50/50 coal-to-coke ratio and 23.3 percent control effectiveness. However, LNA cites operational issues with fuel ash content above 6.5 percent. Since ash is a contaminant that can adversely affect lime product quality, we are seeking comment regarding the extent to which it is appropriate to use fuel ash content of 6.5 percent as the upper bound for determining fuel mixture ratio. We may finalize a different fuel mixture ratio based upon the comments we receive.

In estimating the costs of compliance, LNA relied on a vendor quote for purchased equipment provided by Noltech dated May 22, 2013, with the remainder of the capital costs calculated using the cost methodology contained in EPA's Control Cost Manual.[87] While these capital costs are higher than those estimated by our contractor, we consider the use of the

[86] While the control efficiency for DSI is much higher for cement kilns, LNA conducted onsite testing of DSI on the lime kilns at the Nelson Plant that demonstrated it is appropriate to use 40 percent control efficiency. The docket includes a comparison of LNA's tests of DSI to the analysis in our contractor's report.
[87] Vendor quote included as an attachment to *BART Five Factor Analysis, Lhoist North America Nelson Lime Plant*; (Public version dated September 27, 2013).

Noltech vendor quote for the Nelson Plant reasonable, and have incorporated it into our evaluation of the costs of compliance. With regard to annual operating & maintenance costs, LNA has asserted a confidential business information (CBI) claim regarding certain annual operating costs such as reagent usage. As a result, we have prepared our own independent estimate of annual operating costs based upon a combination of publicly available data and certain assumptions as described in the contractor's report. Detailed cost calculations can be found in the docket.[88]

TABLE 23—NELSON LIME PLANT: SO_2 CONTROL OPTION EMISSION ESTIMATES

SO_2 Control Technology	Control Efficiency (%)	Emission Factor (lb/ton lime)	Maximum Emission Rate		Removed (tpy)
			lb/day	tpy	
Kiln 1					
Baseline	--	12.15	10,526	1,571	--
Lower Sulfur Fuel Blend	23.30%	9.32	8,073	1,205	366
Dry Sorbent Injection	40%	7.29	6,316	943	628
Kiln 2					
Baseline	--	12.69	15,808	2,400	--
Lower Sulfur Fuel Blend	23.30%	9.73	12,125	1,841	559
Dry Sorbent Injection	40%	7.61	9,485	1,440	960

TABLE 24—NELSON LIME PLANT: SO_2 CONTROL OPTION COST-EFFECTIVENESS

SO_2 Control Technology	Capital Cost	Annual Direct Costs	Annual Indirect Costs	Total Annual Cost	Emission Reduction	Cost-Effectiveness ($/ton)	
	($)	($/yr)	($/yr)	($/yr)	(tpy)	Average	Incremental
Kiln 1							
Lower Sulfur Fuel Blend	--	--	--	$313,096	366	$856	--
Dry Sorbent Injection	$2,497,559	$371,174	$2,621,832	$2,621,832	628	$4,174	$8,803
Kiln 2							
Lower	--	--	--	$458,179	559	$819	--

[88] See spreadsheet "Nelson Control Costs 2013-10-24.xlsx" in the docket.

Sulfur Fuel Blend							
Dry Sorbent Injection	$2,497,559	$371,174	$3,895,774	$3,895,774	960	$4,058	$8,576

Pollution Control Equipment in use at the Source: The presence of existing pollution control technology at the Nelson Plant is reflected in the BART analysis in two ways: first, in the consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling. In the case of SO_2, the kilns at the Nelson Plant do not operate with any existing control technology. This is reflected in the baseline emission rates, which represent uncontrolled SO_2 emissions.

Energy and non-air quality environmental impacts: Regarding the first option, DSI systems require electricity for operation. The generation of the electricity needed to operate a DSI system will likely involve fuel combustion that will generate emissions. Emissions also are associated with the transport, handling, and storage of sorbent. Overall, while the use of DSI will cause emissions from select activities, the emissions should be low compared to the reduction in SO_2 that would be gained by operating a DSI system. Regarding the second option, using a lower sulfur fuel blend means LNA will obtain more of the energy for lime production from coal and less of the energy from coke. Since the heating value of coke is slightly higher than the heating value of coal, it is likely that LNA will burn more total mass of fuel as a result of substituting some coal for coke. While burning a lower sulfur fuel blend will likely result in a reduction in SO_2 emissions, it will involve the overall use of greater quantities of coal, which may result in a collateral increase of other pollutants such as NO_x and CO.

Remaining Useful Life of the Source: We are considering the “remaining useful life” of the kilns as one element of the overall cost analysis as allowed by the BART Guidelines. In the absence of any enforceable closure date, we have used a 20-year amortization period described in the EPA Cost Control Manual as the remaining useful life for the control options considered for the Nelson Plant kilns. Since there is no capital costs associated with using a lower sulfur fuel blend, the remaining useful life of the kilns is not a factor in the evaluation of this technology.

Degree of Visibility Improvement: As was the case for NO_x, EPA post-processed LNA's modeling results for SO_2 controls. The greatest improvement from DSI is 0.2 dv, occurring at the Grand Canyon, with improvements at other areas a third or less than this. The cumulative improvement is 0.6 dv. The maximum and cumulative improvements from switching to lower sulfur fuel are roughly half of these amounts. While visibility improvement by itself could support either DSI or lower sulfur fuel as BART, lower sulfur fuel is favored by its much lower average cost-effectiveness at $819-856/ton compared to over $4000 for DSI. Baseline and control option emission rates used in SO_2 control scenario modeling are summarized in Table 25 with the modeling results in Table 26.[89]

TABLE 25—NELSON LIME PLANT: SO_2 CONTROL MODEL EMISSION RATES

SO_2 Control Technology	Control Efficiency	Emission Factor	Maximum 24-hr Model Emission Rate		
	%	lb/ton lime	lb/day	lb/hr	g/s
Kiln 1					
Baseline	--	12.15	10,526	439	55
Lower Sulfur Fuel Blend	23.30%	9.32	8,073	336	42
Dry Sorbent Injection (SBC)	40%	7.29	6,315	263	33
Kiln 2					
Baseline	--	12.69	15,808	659	83
Lower Sulfur Fuel Blend	23.30%	9.73	12,125	505	64
Dry Sorbent Injection (SBC)	40%	7.61	9,489	395	50

TABLE 26—NELSON LIME PLANT: SO_2 CONTROL OPTION VISIBILITY MODELING RESULTS

89 These results are from EPA's post-processing of LNA's modeling. See the TSD for a discussion of the differences between EPA's results and the results reported by LNA in their BART analysis.

Class I Area	Distance (km)	Visibility Impact	Visibility Improvement	
		Base Case	DSI (ctr2)	Low-S Fuel (ctr3)
Bryce Canyon NP	235	0.20	0.03	0.02
Grand Canyon NP	24	1.79	0.21	0.10
Joshua Tree NP	238	0.23	0.07	0.04
Mazatzal WA	206	0.15	0.04	0.02
Pine Mountain WA	199	0.15	0.04	0.02
Sierra Ancha WA	289	0.11	0.04	0.02
Superstition WA	288	0.13	0.04	0.02
Sycamore Canyon WA	132	0.31	0.06	0.04
Zion NP	183	0.28	0.04	0.02
Cumulative (sum)		3.34	0.57	0.29
Maximum		1.79	0.21	0.10
# CIAs >= 0.5 dv		1	0	0
million $/dv (cumul. dv)			$11.5	$2.6
million $/dv (max. dv)			$30.7	$8.1

c. Proposed BART Determination for SO_2

We propose to find that BART for SO_2 is the use of a lower sulfur fuel blend with an emission limit of 9.32 lb/ton for Kiln 1 and 9.73 lb/ton for Kiln 2[90] on a rolling 30-day basis. In evaluating the costs of compliance, we note that we consider DSI and lower sulfur fuel to both be cost-effective control options, with average cost-effectiveness values of approximately $800/ton and $4,000/ton, respectively. In evaluating anticipated visibility benefit, while DSI is anticipated to achieve the greatest visibility improvement (0.21 dv at Grand Canyon), this amount of visibility improvement is not large, nor is the benefit anticipated for the next most stringent control option, lower sulfur fuel (0.10 dv at Grand Canyon). In considering the other factors, there is no significant effect on the outcome of the cost and visibility analyses. The lack of

[90] The differing emission limits are due to the different baseline performance of the two kilns.

existing control technology is reflected in the baseline in the form of uncontrolled SO_2 emissions. In examining energy and non-air quality impacts, we note that there may be certain collateral increases in emissions, but that these increases are outweighed by the emission reductions achieved by implementing the control technology and do not warrant their elimination. The remaining useful life of the source is reflected in the evaluation of the cost of compliance. We consider both DSI and use of lower sulfur fuel to be cost-effective, but note that the most stringent option, DSI, is considerably less cost-effective than the use of lower sulfur fuel, with an incremental cost-effectiveness, relative to lower sulfur fuel, of approximately $9,000/ton. As a result, although DSI is the most stringent control option, the visibility benefit it achieves is not large, and is achieved at a very high incremental cost relative to the next most stringent control option. Based on this information, we propose to find that BART for SO_2 is the use of a lower sulfur fuel blend.

4. Proposed BART for PM_{10}

For our BART analysis, we identified fabric filter baghouses, the existing control technology for PM_{10} on Kilns 1 and 2, as the most stringent control available for this type of source.

a. Control Technology Analysis for PM_{10}

The Nelson Plant, as a major source of hazardous air pollutants (HAPs), is subject to the Maximum Achievable Control Technology (MACT) Standard for Lime Manufacturing Plants, and is required to meet an emission limit of 0.12 lbs PM/TSF (ton of stone feed).[91] The BART Guidelines provide that unless there are new technologies subsequent to the MACT standards that would lead to cost-effective increases in the level of control, one may rely on the MACT

[91] 40 CFR 63, Subpart AAAAA, Table 1, Item 1 for existing lime kilns with no wet scrubber prior to 2005.

standards for purposes of BART.[92] Based on information developed as part of the Lime MACT, we estimate that existing fabric filter upgrades would result in annual costs of $94,500.[93] As noted in LNA's BART analysis, baseline PM emissions for the two kilns, based on PM filterable stack test data and annual lime production, are approximately 8 tpy and 15 tpy.[94] This would result in an average cost-effectiveness of about $6,300 to $12,000/ton.

b. BART Analysis for PM_{10}

The BART Guidelines provide that, in instances where a source already has the most stringent controls available (including all possible improvements), it is not necessary to complete each step of the BART analysis. Further, as long as the most stringent controls available are made federally enforceable for the purpose of implementing BART for that source, one may skip the remainder of the analysis, including the visibility analysis.[95]

c. Proposed BART Determination for PM_{10}

We propose a BART emission limit of 0.12 lb /TSF to control PM_{10} at Kilns 1 and 2 based on the use of the existing fabric filter baghouses and commensurate with the MACT standard that applies to this source. We seek comment on any cost-effective upgrades or improvements that may result in a lower emission limit. We propose to require compliance with this requirement within 6 months after the effective date of the final rule. We also propose regulatory text that includes monitoring, reporting, and recordkeeping requirements associated with this emission limit that is found at the end of this notice.

C. Hayden Smelter

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[92] 40 CFR Part 51, Appendix Y, Section IV.C.

[93] Annual costs as described in the Economic Impact Analysis for the Lime Manufacturing MACT Standard (EPA-452/R-03-013), Table 3-2, Model Kiln F. Adjusted from 1997 to 2013 dollars using the consumer price index, available at ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt.

[94] As described in the LNA Nelson BART Analysis, Table 4-5.

[95] 40 CFR Part 51, Appendix Y, Section IV.D.9.

Summary: EPA proposes to find that the ASARCO Hayden Smelter is subject to BART for NO_x in addition to SO_2 as determined by the State. ASARCO must capture and control SO_2 emissions from the converter units that are subject to BART. In the current method of operation, thousands of tons of SO_2 from these units are vented to the atmosphere with no pollution control. One method to control SO_2 emissions from the converter units is to install and operate a second double contact acid plant with a control efficiency of about 99.8 percent on a 30-day rolling average. We estimate the annual cost of constructing and operating a second acid plant to control SO_2 emissions is about $872 per ton of SO_2 removed. While we consider the cost of a new acid plant to be reasonable, we are proposing a performance standard as BART rather than prescribing a particular method of control. For NO_x, we propose to set an annual emission limit of 40 tpy from the BART-eligible units, based on our proposed determination that no NO_X controls are needed for BART at the Hayden Smelter. Finally, we are proposing an emission limit and associated compliance requirements for PM_{10}.

Affected Class I Areas: Twelve Class I areas are within 300 km of the Hayden Smelter. Their nearest borders range from 48 km to 239 km away. Galiuro WA and Superstition WA are the closest, followed by Saguaro NP and Sierra Ancha WA. The highest baseline 98th percentile visibility impact is 1.7 dv at Superstition, with impacts at Galiuro slightly lower. Baseline visibility impacts at each of the twelve areas exceed 0.5 dv. The cumulative sum of visibility impacts over all the Class I areas is 12.1 dv.

Facility Overview: ASARCO Hayden Smelter is a batch-process copper smelter in Gila County, Arizona. We previously approved ADEQ's determination that converters 1, 3, 4 and 5 and Anode Furnaces 1 and 2 at the facility are BART-eligible.[96] We also approved ADEQ's determination that these units are subject to BART for SO_2 and that BART for PM_{10} at ASARCO

[96] 78 FR 46412 (July 30, 2013). Please refer to the TSD for a description of these units.

Hayden is no additional controls. However, we disapproved ADEQ's determination that existing controls constitute BART for SO_2 and that the units are not subject to BART for NO_x. In light of these disapprovals and our FIP duty for regional haze in Arizona, we are required to promulgate a FIP to address BART for SO_2 and NO_x.

Baseline Emissions Calculations: Since neither ASARCO nor ADEQ identified baseline emissions for the Hayden Smelter, we calculated baseline emissions for SO_2 and NO_x. For $SO_{2,}$ we used as the baseline the average of the two highest emitting years from the last five years that ASARCO reported to ADEQ. For NO_x, we estimated emission rates based on the rated natural gas capacity of the burners in the four subject-to-BART converters and the two anode furnaces.[97] As indicated in Table 27, the majority of the source's SO_2 emissions (20,341 tpy of a total of 22,621 tpy) are process emissions from the converters. These process SO_2 emissions are collected through a secondary capture system, but are emitted uncontrolled through an annular stack that bypasses the existing double contact acid plant. While our BART analysis focuses on these uncontrolled SO_2 emissions from the converters, we also evaluated improved control of the SO_2 emissions from the existing acid plant and from the anode furnaces as well as controlling NO_x emissions from all the BART units.

TABLE 27—HAYDEN SMELTER: BART BASELINE EMISSIONS (TONS PER YEAR)

	Converters			Anode Furnaces	Total
	Existing Acid Plant (Primary Capture)	Annular Stack (Secondary Capture)	Uncaptured		
SO_2	1,034	20,341	1,209	37	22,621
NO_x	31			19	50

Modeling Overview: EPA is relying on modeled baseline and post-control impacts of the ASARCO Hayden Smelter using stack parameters provided by ASARCO in response to a 2013

[97] ASARCO Hayden Title V permit.

EPA information request.[98] We also modeled using stack parameters based on a 2012 stack test.[99] Stack exit temperatures were comparable for these two models, but the exit velocities from the 2012 stack test were far lower than those provided by ASARCO in 2013. The 2012 stack test parameters resulted in visibility impacts and control benefits about 10 percent higher than the model using the 2013 parameters. We are conservatively using the 2013 ASARCO parameters to evaluate controls, since using the 2012 parameters would yield even greater visibility improvements. For both sets of modeling runs, EPA used emission rates that were developed using information provided by ASARCO.

1. BART Analysis and Determination for SO_2 from Converters

a. Control Technology Availability, Technical Feasibility and Effectiveness

EPA identified two available technology options to control the 20,341 tons of SO_2 emissions from the annular stack that are captured by a secondary collection system, but are released uncontrolled through the annular stack. These options are to construct and operate a second double contact acid plant or install a wet scrubber on the annular portion of the existing stack. In addition, we found that ASARCO could add a tail stack scrubber to the existing acid plant to address the remaining emissions that are not converted and removed as sulfuric acid by the acid plant. Regarding technical feasibility, we note that ASARCO Hayden currently uses a double contact acid plant to control SO_2 emissions captured by the primary capture system. Wet scrubbing also is commonly used in many industries to control SO_2. Thus, we find that the double contact acid plant and wet scrubbing are technically feasible. In terms of control effectiveness, ASARCO indicated in a letter[100] to EPA that its double contact acid plant is

[98] Letter from Jack Garrity, ASARCO to Thomas Webb, EPA, July 11, 2013; attached Memorandum from Ralph Morris and Lynsey Parker, ENVIRON, to Eric Hiser, Jorden, Bischoff and Hiser, PLC, March 4, 2013.
[99] ASARCO Hayden CEMS Test Report, Energy and Environmental Measurement Corporation, Test date: September, 2012.
[100] Letter from Jack Garrity, ASARCO to Thomas Webb, EPA (July 11, 2013).

capable of recovering 99.81 percent of the SO_2 vented to it.[101] In the same letter, ASARCO noted that the expected control effectiveness of wet scrubbing is 85 percent. We used these removal efficiencies in our five-factor analyses. These analyses are explained in the TSD and summarized below.

b. Option 1: Double Contact Acid Plant for Secondary Capture

Cost of Compliance: EPA determined the cost-effectiveness of a new double contact acid plant is $872 per ton of SO_2 removed as shown in Table 28. As explained in the TSD, we conservatively estimated the cost of construction of a double contact acid plant to be $81,621,297. The annualized capital costs are based on a 20-year lifespan and a seven percent interest rate. We applied a control efficiency of 99.8 percent, which the existing acid plant is currently achieving with limited cesium catalyst. The emission reduction was applied to the secondary capture system baseline emissions. This cost analysis does not include the offsetting value of any sulfuric acid produced and sold. It does assume full catalyst replacement every other year and air preheating with natural gas for 8,760 hours per year.

TABLE 28—HAYDEN SMELTER OPTION 1: SECOND DOUBLE CONTACT ACID PLANT

Capital Cost	Annualized Capital Cost	Annual Variable Cost	Total Annual Cost	Tons SO_2 Reduced	Control Efficiency	$/ton SO_2 Removed
$81,621,297	$7,704,573	$10,006,010	$17,710,483	20,341	99.81%	$872

Energy and Non-Air Quality Environmental Impacts: Controlling secondary capture with a sulfuric acid plant at the Hayden Smelter would require energy to heat inlet air from approximately 177° F to 735° F. This would require a heat input of approximately 114 MMBtu/hour and could require 1,200 MMscf of natural gas per year, resulting in up to 30 tpy of

[101] *Ibid.*

NO_x emissions.[102] This assumes 100 percent of the needed heat results from natural gas combustion. Non-air quality impacts from a second acid plant are not expected to be significant given that ASARCO already has the capacity to handle and store the much larger quantities of sulfuric acid produced by the primary acid plant.

Pollution Control Equipment in Use at the Source: As noted above and further described in the TSD, a portion of the emissions from the converters are controlled by a gas cleaning plant to remove particulate matter and a double contact sulfuric acid plant that converts SO_2 to sulfuric acid. We considered these controls as part of our analysis of available control technologies and in developing baseline emission rates for use in cost calculations and visibility modeling.

Remaining Useful Life of the Source: The BART-eligible converters have each been in place for about 40 years or longer. ASARCO has not indicated that any of the converters would need to be replaced during the 20-year capital cost recovery period.

Degree of Visibility Improvement: Controlling SO_2 emissions through a second double contact acid plant at a 98.8 percent efficiency results in visibility improvement in 12 Class I areas in Arizona and New Mexico as indicated in Table 29. Based on air quality modeling, visibility improvement from controlling SO_2 by constructing a new acid plant to control converter emissions from the secondary capture system is 1.5 dv at Superstition, and nearly the same at Galiuro. Eleven of the Class I areas improve by at least 0.5 dv. The cumulative improvement is 10.3 dv. The large visibility improvement at many Class I Areas supports the choice of a new acid plant as BART for SO_2.

TABLE 29—HAYDEN SMELTER OPTION 1: VISIBILITY IMPACT AND IMPROVEMENT FROM SO_2 CONTROLS

Class I Area	Distance (km)	Visibility Impact	Visibility Improvement

[102] This is based on the AP 42 factor for low-NO_x burners.

		Base Case (base)	New Acid Plant (ctrl2)
Chiricahua NM	170	1.05	0.89
Chiricahua WA	174	1.01	0.87
Galiuro WA	48	1.73	1.45
Gila WA	186	0.69	0.60
Mazatzal WA	121	0.88	0.75
Mount Baldy WA	151	0.66	0.56
Petrified Forest NP	215	0.70	0.61
Pine Mountain WA	168	0.67	0.57
Saguaro NP	82	1.38	1.18
Sierra Ancha WA	84	1.09	0.93
Superstition WA	50	1.74	1.47
Sycamore Canyon WA	239	0.51	0.44
Cumulative (sum)		12.10	10.32
Maximum		1.74	1.47
# CIAs >= 0.5 dv		12	11
million $/dv (cumul. dv)			$1.7
million $/dv (max. dv)			$12.1

c. Option 2: Wet Scrubber on Existing Stack for Secondary Capture

Cost of Compliance: EPA determined that the annual cost of using a wet scrubber to control SO_2 emissions from the secondary capture system is $972 per ton of SO_2 removed as displayed in Table 30. We calculated the costs of constructing and operating a wet scrubber based on information provided in ASARCO's letter[103] from which we used the highest operating cost estimates to demonstrate cost-effectiveness. We also included a sludge hauling fee of $60 per ton and assumed one ton of SO_2 controlled would result in five tons of sludge. According to ASARCO, these costs do not include the cost of a booster fan or a modified stack that may be needed, thereby somewhat increasing the cost over what is shown here. Although the calculation

[103] Letter from Jack Garrity, ASARCO to Thomas Webb, EPA (July 11, 2013).

includes the cost of hauling sludge off site, it does not include the cost of treating or landfilling the sludge.

TABLE 30—HAYDEN SMELTER OPTION 2: WET SCRUBBER ON EXISTING STACK

Capital Cost	Annualized Capital Cost	Annual Variable Cost	Total Annual Cost	Tons SO_2 Reduced	Control Efficiency	\$/ton SO_2 Removed
\$28,000,000	\$2,643,002	\$14,186,965	\$16,829,967	17,290	85%	\$972

Energy and Non-Air Quality Environmental Impacts: Operation of a wet scrubber would likely require operation of a booster fan and a gas re-heater to force emissions through the 305 meter stack. The addition of a wet scrubber could result in a detached visible plume as water vapor emitted from the scrubber condenses. Addition of a scrubber would result in sludge which would have to be shipped off site to be treated or landfilled. Because of metals in the sludge, it may need to be treated as hazardous waste.

Pollution Control Equipment in Use at the Source: This is the same as for Option 1.

Remaining Useful Life of the Source: This is the same as for Option 1.

Degree of Visibility Improvement: We did not conduct visibility modeling for this option. Because a scrubber is less efficient at removing SO_2 than a second acid plant, the emission rates would be higher and there would be less visibility improvement from a scrubber compared to an acid plant. Given that scrubbers are less cost-effective than a second acid plant, we deemed it unnecessary to model impacts.

d. Option 3: Wet Scrubber on Acid Tail Stack for Primary Capture

Cost of Compliance: EPA determined the annual cost of using a wet scrubber to control SO_2 emissions from the existing acid plant tail stack is \$13,564 per ton of SO_2 removed as displayed in Table 31. We calculated the costs of constructing and operating a wet scrubber based on information provided by ASARCO.[104] In this case, we used the low-end estimate of operating costs because we are demonstrating that this option is not cost-effective. We also included a sludge hauling fee of $60 per ton and assumed one ton of SO_2 controlled would result in five tons of sludge. Again, these costs did not include the cost of a booster fan or a modified stack that may be needed. Although the calculation included the cost of hauling sludge off site, it did not include the cost of treating or disposing the sludge, which may be classified as hazardous waste depending on the metals content. In addition, we note that some of the SO_2 that passes through the acid plant is emitted by the flash furnace that is not BART-eligible.

TABLE 31—HAYDEN SMELTER OPTION 3: WET SCRUBBER ON ACID TAIL STACK

Capital Cost	Annualized Capital Cost	Annual Variable Cost	Total Annual Cost	Control Efficiency	Tons SO_2 Reduced	$/ton SO_2 Removed
$28,000,000	$2,643,002	$9,274,521	$11,917,523	85%	879	$13,564

Energy and Non-Air Quality Environmental Impacts: This is the same as for Option 2.

Pollution Control Equipment in Use at the Source: This is the same as for Options 1 and 2.

Remaining Useful Life of the Source: This is the same as for Options 1 and 2.

Degree of Visibility Improvement: We did not conduct visibility modeling for a tail stack scrubber because of the high control cost per ton of SO_2. However, because the scrubber would remove much less SO_2 than options 1 or 2 (second acid plant and wet scrubber on the secondary capture, respectively), the expected visibility improvement is far less than for options 1 and 2.

e. Proposed BART Determination for SO_2 from Converters

Based on the results of our BART analysis, we propose that BART for SO_2 from the converters is a level of control consistent with what ASARCO could achieve through the

[104] *Ibid.*

installation of a new double contact acid plant. This would control about 20,341 tpy of SO_2 emissions from the converter units at a cost of about $872 per ton of SO_2 removed, which we consider highly cost-effective. The expected visibility benefits of this option are substantial with a greater than 0.5 dv improvement in eleven Class I areas with a maximum benefit of 1.47 dv at Superstition WA. We propose to find that the energy and non-air quality environmental effects of this option are not sufficient to warrant elimination of this option.

Regarding the other options, a wet scrubber for the secondary capture (Option 2) is less effective at a similar annual cost but with greater non-air environmental impacts. Therefore, we do not propose to require this as BART. Adding a scrubber to the existing acid tail stack for the primary capture (Option 3) would result in a relatively small amount of additional emissions reductions at a relatively high cost ($13,564 per ton of SO_2 removed) and with potentially significant non-air environmental impacts. Therefore, we propose that the addition of a scrubber to the existing acid plant is not required as BART.

The specifics of our BART proposal for SO_2 from the converters are as follows:

- An SO_2 control efficiency of 99.8 percent, 30-day rolling average, on all SO_2 captured by the primary and secondary control systems. The control efficiency may be averaged between the two capture systems on a mass basis, if needed. (For every 30-day period the total mass of SO_2 exiting the two control systems must be no greater than 0.0019 percent of the SO_2 entering the control systems.)
- Compliance with the SO_2 BART limit may be verified either through the use of SO_2 CEMS before and after controls in each system or by using post-control CEMS and acid production rates. A limit of 2.49 lbs SO_2 emissions per tons of sulfuric acid production is equivalent to 99.8 percent control.

- Operation and maintenance of primary and secondary capture systems meeting the requirements of 40 CFR 63, subpart QQQ.

We propose to require that these requirements be met within 3 years of promulgation of the final rule, consistent with the requirement of the CAA and the RHR that BART be installed "as expeditiously as practicable."

2. BART Analysis and Determination for SO_2 from Anode Furnaces

a. BART Analysis for SO_2 from Anode Furnaces

We identified the same two control technologies for the anode furnaces: a new double contact acid plant and a wet scrubber. In addition, we considered whether emissions from the anode furnaces might be vented to the existing acid plant.

Cost of Compliance: Based on our calculations, we estimated that the cost to control 37 tpy of SO_2 from the anode furnaces by construction of a new acid plant is over $28,000 per ton, not including the cost of inlet preheating,[105] as shown in Table 32. The estimated cost of installing and operating a wet scrubber is even more expensive at over $80,000 per ton[106] as shown in Table 33.

TABLE 32—HAYDEN SMELTER: NEW ACID PLANT FOR THE ANODE FURNACES

Capital Cost	Annualized Capital Cost	Annual Variable Cost	Total Annual Cost	Tons SO_2 Reduced	Control Efficiency	\$/ton SO_2 Removed
$8,583,190	$810,192	$261,827	$1,071,920	37	99.81%	$28,616

TABLE 33—HAYDEN SMELTER: NEW WET SCRUBBER FOR THE ANODE FURNACES

Capital Cost	Annualized Capital Cost	Annual Variable Cost	Total Annual Cost	Tons SO_2 Reduced	Control Efficiency	\$/ton SO_2 Removed
$7,000,000	$660,750	$2,009,570	$2,670,320	32	85%	$83,708

105 See the TSD for further discussion of this issue.
106 See the TSD, Section III.D.4.

Energy and Non-Air Quality Environmental Impacts: This is the same as for the converters.

Pollution Control Equipment in Use at the Source: The anode furnaces currently have no SO_2 controls in place.

Remaining Useful Life of the Source: ASARCO has not indicated that any of the anode furnaces would need to be replaced during the 20-year capital cost recovery period.

Degree of Visibility Improvement: We did not conduct visibility modeling for the anode furnace emissions. However, since the emissions from these units are a small fraction of those from the converters, the expected visibility improvement would be far less than for any of the controls considered for the converters.

b. Proposed BART Determination for SO_2 from Anode Furnaces

Given the high cost of control, and the small potential for visibility improvement, we propose that controlling the 37 tpy of SO_2 emissions from the anode furnaces is not warranted as BART. Furthermore, while redirecting the anode furnace emissions to the existing acid plant might be technically feasible and cost-effective, the emission reductions and visibility benefit, although not calculated, would be much smaller than the calculated benefits from controlling additional emissions from the converters.

In order to ensure that emissions from anode furnaces do not increase substantially in the future, we are proposing to establish a work practice standard for these units. While BART determinations are generally promulgated in the form of numeric emission limitations, the RHR allows for use of equipment requirements or work practice standards in lieu of a numeric limit where “technological or economic limitations on the applicability of measurement methodology to a particular source would make the imposition of an emission standard infeasible."[107] In this case, we find that a numerical emission limitation for the anode furnaces would be infeasible because of the relatively small amount of emissions from these units, compared with the converters. Therefore, we are proposing to establish a work practice standard in the form of a requirement that the anode furnaces be charged with blister copper or higher purity copper. Because blister copper is generally 98 to 99 percent pure copper, this requirement will ensure that sulfur emission from the anode furnaces are minimized.

3. Subject-to-BART, BART Analysis and BART Determination for NO_x

a. Proposed Subject-to-BART Finding for NO_x

As explained in our final rule on the Arizona RH SIP, once a source is determined to be subject to BART, the RHR allows for the exemption of a specific pollutant from a BART analysis only if the potential to emit for that pollutant is below a specified de minimis level.[108] Neither the Hayden Smelter's current Title V permit nor the Arizona RH SIP contains any physical or operational limitations that would limit the PTE of the BART-eligible source below the NO_x de minimis threshold of 40 tpy. Therefore, because the Hayden Smelter is subject to BART and has a PTE of more than 40 tons per year of NO_x, we have analyzed potential NO_x BART controls for the source.

b. BART Analysis for NO_x

The Hayden Smelter's NO_x emissions result from the combustion of natural gas to heat process equipment. LNB are an available, feasible and effective technical option for such process heaters, with an estimated control efficiency of 50 percent.[109]

[107] 40 CFR 51.308(e)(1)(iii). See also 40 CFR 51.100(z)(defining "emission limitation" and "emission standard" to include "any requirements which . . . prescribe equipment . . . for a source to assure continuous emission reduction."
[108] 40 CFR 51.308(e)(1)(ii)(C).
[109] AirControlNet, Version 4.1, documentation report by E.H. Pechan and Associates, Inc. for U.S. EPA, Office of Air Quality, Planning, and Standards, May 2006, section III, page 445.

Cost of Compliance: According to the Documentation Report accompanying AirControlNet, the cost to retrofit process heaters with LNB is $2,200 per ton.[110]

Energy and Non-Air Quality Environmental Impacts: No significant energy and non-air environmental impacts are expected to result from use of LNB.

Pollution Control Equipment in Use at the Source: No NO_x controls are currently employed at either the converters or the anode furnaces.

Remaining Useful Life of the Source: ASARCO has not indicated that any of the units would need to be replaced during the 20-year capital cost recovery period.

Degree of Visibility Improvement: The maximum modeled 98th percentile visibility impact resulting from baseline NO_x emissions from the Hayden Smelter is no higher than 0.01 dv[111] at any of the Class I areas. Thus, the maximum visibility benefit of controls is less than 0.01 dv.

c. Proposed BART Determination for NO_x

Given the small potential for visibility improvement, we propose that controlling these NO_x emissions is not warranted for purposes of BART. However, in order to ensure that NO_x emissions do not increase in the future, we propose to set a 12-month rolling limit of 40 tons of NO_x from the subject-to-BART units, which is equivalent to the de minimis level of emissions set out in the RHR.[112] This emission limit is slightly lower than the annual 50 tpy baseline emissions noted above. Nonetheless, we consider it to be a reasonable limit because the 50 tpy estimate assumes that all of the converters are all operating simultaneously, which is not how

[110] *Id.*
[111] Summary of WRAP RMC BART Modeling for Arizona, Draft Number 5, May 25, 2007. Also, ASARCO response letter, July 11, 2013, ENVIRON memo attachment, March 4, 2012, ("H-09 2013-03-04 ENVIRON report-Asarco-Hayden-BART.pdf".
[112] 40 CFR 51.308(e)(1)(ii)(C).

they typically operate. Therefore, we expect actual emissions to be well below 40 tpy, which is consistent with ASARCO's own estimate.[113]

4. Summary of EPA's Proposed BART Determinations

We propose that BART for SO_2 from the converters is a control efficiency of 99.8 percent, 30-day rolling average, on all SO_2 captured by the primary and secondary control systems. We propose to require compliance with this requirement within three years of promulgation of a final rule. We also are proposing monitoring, recordkeeping and reporting as well as operation and maintenance requirements, to ensure the enforceability of our proposed BART determination. We propose a work practice standard consistent with current practices for the anode furnaces. We also propose to set a 12-month rolling limit of 40 tons of NO_x from the subject-to-BART units.

We are seeking comment on all aspects of this proposal. In particular, we are seeking comment on the following elements of our BART analysis and determination for SO_2 from the converters:

- the cost of controls;
- the collection efficiency for the primary collection system;
- the collection efficiency for the secondary collection system;
- the control efficiency to be applied to the primary and secondary collections systems;
- the compliance methodology; and
- the compliance schedule.

If we receive additional information concerning these or other elements of our analysis, we may finalize a BART determination that differs in some respects from this proposal.

D. Miami Smelter

[113] Letter from Krishna Parameswaran, ASARCO, to Gregory Nudd, EPA dated March 6, 2013, page 15.

Summary: EPA proposes to find that the Miami Smelter is subject to BART for NO_x in addition to SO_2 and PM_{10}, as determined by the State. For SO_2 from the converters, we propose to require construction of a secondary capture system consistent with the requirements of MACT QQQ and an SO_2 control efficiency of 99.7 percent, 30-day rolling average, on all SO_2 captured by the primary and secondary capture systems. For SO_2 emissions from the electric furnace, we propose to prohibit active aeration of the electric furnace. For NO_x, we propose to find that controlling emissions from the converters and anode furnaces is cost-effective, but would not result in sufficient visibility improvement to warrant the cost. Therefore, we are proposing an annual emission limit of 40 tpy NO_x emissions from the BART-eligible units at the Miami Smelter, which is consistent with current emissions from these units. We previously approved Arizona's determination that BART for PM_{10} at the Miami Smelter is the NESHAP for Primary Copper Smelting. Please refer to the Long Term Strategy in Section VII below, regarding our proposal to ensure the enforceability of this determination.

Affected Class I Areas: Twelve Class I areas are within 300 km of the Miami Smelter with the nearest borders ranging from 55 km to 260 km away. The set of areas differs from the ones near the Hayden Smelter only in that Bosque Del Apache WA is included, and Sycamore Canyon WA is not. The baseline visibility impacts are 0.70 dv or less at all Class I areas except at Superstition where the visibility impact is 3.6 dv. The cumulative sum of visibility impacts at all areas within 300 km is 8.2 dv.

Facility Overview: The Miami Smelter is a batch-process copper smelter in Gila County, Arizona. We previously approved ADEQ's determination that Hoboken Converters 2, 3, 4 and 5 and the Electric Furnace at the facility are BART-eligible.[114] We also approved ADEQ's determination that these units are subject to BART for SO_2 and that BART for PM_{10} at the

[114] 78 FR 46412 (July 30, 2013). See also the TSD for a description of these units.

Miami Smelter is the Maximum Achievable Control Technology (MACT) Subpart QQQ under the National Emission Standards for Hazardous Air Pollutants (NESHAP) for primary copper smelting. However, we disapproved ADEQ's determination that existing controls constitute BART for SO_2 and that the units are not subject to BART for NO_x. In light of these disapprovals and our FIP duty for Regional Haze in Arizona, we are required to promulgate a FIP to address BART for both SO_2 and NO_x.

Baseline Emissions: Because neither FMMI nor ADEQ identified baseline emissions for the Miami Smelter, we selected emissions from 2010 as the baseline. We chose 2010 because ADEQ provided the most detailed emissions information from this year in its RH SIP and because FMMI used 2010 as a basis for calculating uncaptured emissions of SO_2 for 2011 and 2012. FMMI reports emissions of SO_2 to ADEQ by stack, and performs a mass-balance equation to determine uncaptured emissions. SO_2 emissions in tons per year are presented in Table 34 as reported by FMMI to ADEQ for the acid plant duct, acid plant bypass duct, and the vent fume duct.[115] Because each of these stacks vents emissions from both BART and non-BART emission units, EPA apportioned the emissions to BART and non-BART units for purposes of our analysis. The BART-eligible emissions from the acid plant were based on FMMI and ADEQ's estimate that 35 percent of SO_2 sent to the acid plant is emitted by the converters and 65 percent of SO_2 is emitted by the primary smelter (often called by a proprietary name, the IsaSmelt furnace) and electric furnace. Because it is not possible to differentiate which converter emissions are from the one converter that is not BART-eligible, we are treating all converter emissions as subject to BART. Subject-to-BART emissions from the vent fume duct were set at seven tons per year based on our estimate of the share of emissions originating from the electric

[115] The vent fume duct is the stack for a wet scrubber used to control emissions collected by the IsaSmelt secondary collection system, other collection systems associated with conveyors that are not BART-eligible, and emissions collected by the BART-eligible electric furnace secondary collection system.

furnace. Please refer to the TSD for an explanation for how the subject-to-BART uncaptured emissions are determined.

TABLE 34—MIAMI SMELTER: BART BASELINE EMISSIONS FOR SO_2 IN 2010 (TONS PER YEAR)

	Acid Plant Duct	Acid Plant Bypass	Vent Fume Duct	Uncaptured
Total SO_2 Emissions	1,415	93	331	8,472
Subject-to-BART SO_2 Emissions	495	33	7	3,231 – 8,078

FMMI also reports potentially BART-eligible NO_x emissions from the acid plant duct and from "natural gas combustion" to ADEQ as depicted in Table 35. FMMI estimates that 15 percent of NO_x emitted from the acid plant duct originates from the BART-eligible converters. While "natural gas emissions" includes emissions from the converter burners, it is not possible to separate the BART-eligible emissions from ineligible emissions. Thus, we are assuming that all these emissions are BART-eligible.

TABLE 35—MIAMI SMELTER: BART BASELINE EMISSIONS FOR NO_X IN 2010 (TONS PER YEAR)

	Acid Plant Duct	Natural Gas Combustion
Total NO_x Emissions	154	15
Subject-to-BART NO_x Emissions	23	15

Modeling Overview: Using the CALPUFF model, EPA estimated the visibility impacts of the Miami Smelter in its current (i.e., baseline) configuration, and with two different control options for SO_2 emissions. Model inputs were developed using work by the WRAP and updated stack and other information from FMMI. EPA made two different emissions calculations, incorporating high and low estimates of the amount of emissions that are not captured by the existing systems. Most of the discussion below focuses on modeling performed using the high estimate as shown in Table 37.

An additional complication for this facility is that most of the emissions occur via a "roofline," a long rectangular hole in the roof of the building containing the converters. Modeling the roofline as if it were a stack may be problematic, especially for nearby Class I areas. Modeling the roofline as a buoyant line source is a better characterization of the source. EPA performed sensitivity simulations, described in the TSD, and found that impacts do vary depending on whether it is modeled as a stack or a line source. Which modeling scenario resulted in higher impacts depended on the particular Class I area. EPA therefore modeled the main emissions from FMMI as a buoyant line source, despite the considerably longer model run times.

1. BART Analysis for SO_2 from Converters

a. Control Technology Availability, Technical Feasibility and Effectiveness

We identified two available and feasible technologies to control SO_2 emissions from the converters: a double contact acid plant and wet scrubbing. FMMI already uses these two technologies in series to control SO_2 emissions currently captured from the converters. Based on SO_2 acid plant emissions and sulfuric acid production data provided to EPA by FMMI, we calculated that the existing acid plant and tail gas scrubber system is controlling at least 99.7 percent of the SO_2 ducted to the acid plant,[116] which we consider effective. Because FMMI already uses both of the two available control technologies to control SO_2 emissions currently captured from the converters and achieves a high degree of control of these emissions, we did not further evaluate additional controls or upgrades to the existing controls as BART. Rather, we evaluated ways to improve the capture efficiency of the existing system so that additional emissions may be collected and controlled.

[116] Letter from Derek Cooke, FMMI, to Thomas Webb, EPA, Appendices A and C, January 25, 2013.

In order to analyze options for improved capture, we requested information from FMMI regarding potential design improvements, upgrades to existing equipment or new equipment that could increase the degree of capture of SO_2 emissions from the converters.[117] In response, FMMI reported that it planned to improve the converter mouth covers, reconfigure the roofline capture system and route the captured emissions to the existing acid plant.[118] Accordingly, we performed a five-factor BART analysis for these improvements, which we refer to collectively as a "secondary capture system."

b. Secondary Capture System

The purpose of the secondary capture system is to improve capture and control of SO_2 emissions from the converters that can then be directed to the existing double contact acid plant.

Cost of Compliance: FMMI claimed as confidential business information (CBI) the cost information for improvements in SO_2 capture, so we relied on other information to estimate the cost of controls. In particular, we considered cost estimates supplied by ASARCO for the Hayden Smelter, a similar facility, for a series of upgrades to its capture systems.[119] We estimated cost-effectiveness using a capital cost of $47,850,000, and annualized those costs assuming a 20-year lifespan and a 7 percent interest rate with an operation and maintenance cost of 50 percent of the capital cost. We applied a control efficiency of 99.7 percent, which the existing acid plant and tail stack scrubber system currently achieves using very limited cesium catalyst. The emission reduction was applied to 85 percent of the currently uncaptured SO_2 emissions from the converters.[120] Based on these calculations, we estimate the cost-effectiveness

[117] Letter from Thomas Webb, EPA, to Derek Cooke, FMMI (June 27, 2013).
[118] Letter from Derek Cooke, FMMI to Thomas Webb, EPA, Item 2 (July 12, 2013). FMMI indicated that "[t]hese proposed changes are in anticipation of measures that may be adopted by ADEQ as necessary to demonstrate compliance" with the 2012 SO_2 NAAQS." Regardless of their regulatory purpose of the changes, FMMI's proposal indicates that these changes are technically feasible.
[119] See the TSD, Section III.D.4.
[120] *Review of New Source Performance Standards for Primary Copper Smelters*, OAQPS, EPA 450/3-83-018a, March 1984. According to Section 4.7.6.3, the overall collection efficiency of secondary fixed hoods is approximately 90 percent.

of installing and operating a secondary capture system would be \$990 to \$2,474 per ton of SO_2 removed, as shown in Table 36. This range reflects the uncertainty in the quantity of SO_2 emissions that are currently not captured.

TABLE 36—MIAMI SMELTER: COST OF SECONDARY CAPTURE OF SO_2 FROM CONVERTERS

Capital Cost	Annualized Capital Cost	Annual Variable Cost	Total Annual Cost	Tons SO_2 Reduced	Control Efficiency	\$/ton SO_2 Removed
\$47,850,000	\$4,516,701	\$2,258,351	\$6,775,052	2,379–6,845	99.7%	\$990 - 2,474

Energy and Non-Air Quality Environmental Impacts: We do not anticipate significant energy or other non-air quality environmental impacts resulting from capturing and ducting additional emissions to the existing SO_2 control system given that FMMI already has the capacity to handle and store the much larger quantities of sulfuric acid produced by emissions captured from the IsaSmelt and converter primary capture systems.

Pollution Control Equipment in Use at the Source: SO_2 emissions collected from the converters are ducted to the four-pass, double contact acid plant. There is a wet scrubber (the tailstack scrubber) located after the acid plant outlet, to which emissions may be vented during periods of elevated SO_2 concentrations.[121]

Remaining Useful Life: The BART-eligible converters have each been in place for about 40 years. FMMI has not indicated that any of them would be replaced during the 20-year capital cost recovery period.

Degree of Visibility Improvement: As shown in Table 37, installing a secondary capture system to collect and direct SO_2 emissions from the converters to the acid plant, the maximum 98th percentile baseline improvement ranges from a low of 0.41 dv to a high of 1.06 dv at Superstition WA. The cumulative improvement ranges from 1.7 to 4.3 dv. These are large visibility improvements that support using the existing acid plant with a new secondary capture

[121] Letter from Derek Cooke, FMMI to Thomas Webb, EPA, Item 2 (July 12, 2013).

system as BART for SO_2. The high and low visibility impacts and improvements in Table 37 correspond to the range of emissions that are not captured. The range is 3,231 (low) to 8,078 (high) tpy. For the low emission estimate, the maximum improvement from the secondary capture system is 0.41 dv, and the cumulative improvement is 1.7 dv. These are considerably less than for the high emission estimate, which has a maximum improvement of 1.06 dv and cumulative improvement of 4.3 dv, but is still substantial.

TABLE 37—MIAMI SMELTER: VISIBILITY IMPACT AND IMPROVEMENT FROM SECONDARY CAPTURE SYSTEM

Class I Area	Distance (km)	Impact	Improvement from Control	Impact	Improvement from Control
		High Base Case (basehi)	Converter 85% Capture (opt1hi)	Low Base Case (baselo)	Converter 85% Capture (opt1lo)
Bosque del Apache WA	235	0.15	0.12	0.07	0.05
Chiricahua NM	113	0.36	0.27	0.16	0.10
Chiricahua WA	125	0.35	0.27	0.16	0.10
Galiuro WA	99	0.56	0.40	0.28	0.17
Gila WA	55	0.34	0.26	0.16	0.10
Mazatzal WA	220	0.64	0.44	0.32	0.17
Mount Baldy WA	95	0.27	0.20	0.13	0.08
Petrified Forest NP	197	0.33	0.25	0.16	0.10
Pine Mountain WA	260	0.43	0.32	0.20	0.12
Saguaro NP	143	0.45	0.34	0.21	0.13
Sierra Ancha WA	158	0.70	0.40	0.42	0.17
Superstition WA	163	3.61	1.06	2.86	0.41
Cumulative (sum)		8.2	4.3	5.1	1.7
Maximum		3.61	1.06	2.86	0.41
# CIAs >= 0.5 dv		4	1	1	0
million $/dv (cumul. dv)			$1.6		$4.0
million $/dv (max. dv)			$6.4		$16.7

c. Proposed BART Determination for SO_2 from Converters

Based on the results of our BART analysis, we propose that BART for SO_2 from the converters is construction of a secondary capture system (i.e., construction of hooding and ventilation systems to capture escaped SO_2 emissions) and ducting the emissions to existing controls. We have determined that these improvements are feasible and cost-effective, will result in significant visibility improvements, and should not result in significant adverse impacts.

As noted above, the RHR allows for use of equipment requirements or work practice standards in lieu of a numeric limit where "technological or economic limitations on the applicability of measurement methodology to a particular source would make the imposition of an emission standard infeasible."[122] In this instance, we propose to find that technological limitations on the source's ability to measure accurately uncaptured SO_2 emissions make numeric capture efficiency infeasible. Therefore, we are proposing to prescribe specific equipment for capture of SO_2 emissions, in addition to numeric control efficiency and related compliance requirements. Specifically, we are proposing the following as BART for SO_2 from the converters:

- Construction of a secondary capture system consistent with the requirements of MACT QQQ as a work practice standard.
- An SO_2 control efficiency of 99.7 percent, 30-day rolling average, on all SO_2 captured by the primary and secondary capture systems.
- Compliance with the SO_2 BART limit may be verified either through the use of SO_2 CEMS before and after controls or by using post-control CEMS and acid production rates. A limit of 4.06 lbs SO_2 emissions per tons of sulfuric acid production is equivalent to 99.7 percent control.

d. Alternative Control Efficiency

[122] 40 CFR 51.308(e)(1)(iii). See also 40 CFR 51.100(z)(defining "emission limitation" and "emission standard" to include "any requirements which . . . prescribe equipment . . . for a source to assure continuous emission reduction."

We are also seeking comment on whether FMMI should be expected to meet a 99.8 percent control efficiency, 30-day rolling average, on all SO_2 captured by the primary and secondary capture systems. ASARCO Hayden has demonstrated that a control efficiency of 99.8 percent is achievable in practice at a batch copper smelter. FMMI could increase control efficiency by increasing its use of cesium promoted catalyst in the acid plant, increasing the volume of gas exiting the acid plant that is further controlled by the tail stack scrubber, and/or using sodium rather than magnesium in the scrubbing liquor. If we received comments establishing that a control efficiency greater than 99.7 percent is achievable at FMMI, we may finalize a control efficiency of up to 99.8 percent.

2. BART Analysis for SO_2 from Electric Furnace

a. Control Technology Availability, Technical Feasibility and Effectiveness

EPA identified two possible technologies to control SO_2 emissions from the electric furnace: double contact acid plant and wet scrubbing. FMMI has indicated to EPA that emissions from the electric furnace are already controlled by the existing double contact acid plant and tail stack scrubber.[123] In addition, a secondary capture system ducts gases not captured by the primary capture system to the vent fume scrubber, which has a control efficiency of 80 percent. Because FMMI already uses both of the two available control technologies to control SO_2 emissions currently captured from the furnace, we did not evaluate the addition of new controls, nor did we evaluate upgrades to the acid plant system, which already achieves a high degree of control. The one improvement to controls that we identified was upgrading the scrubber, which currently uses magnesium oxide, to use sodium hydroxide, which could increase the control efficiency from 80 percent to 98 percent.

b. Existing Double Contact Acid Plant and Wet Scrubbing

[123] ADEQ Class 1 Permit Number 53592, Application for a Significant Permit Revision, July, 2013.

Cost of Compliance: We estimated the emissions from the electric furnace by multiplying the relevant AP 42 emission factors for copper smelters[124] by the 2010 concentrate throughput provided by FMMI. This results in uncontrolled emissions of SO_2 from the electric furnace of 379 tons per year. Because the scrubber is a secondary control device, however, this would likely result in an emissions decrease of no more than 5 to 10 tons per year. Replacing magnesium oxide with sodium hydroxide would cost at least $2,000,000 per year, resulting in control costs of $200,000 - $400,000 per ton of SO_2 removed, as shown in Table 38.

TABLE 38—MIAMI SMELTER: COST OF UPGRADING VENT FUME SCRUBBER

Capital Cost	Annualized Capital Cost	Annual Variable Cost	Total Annual Cost	Tons SO_2 Reduced	Control Efficiency	$/ton SO_2 Removed
-	-	$2,000,000	$2,000,000	5-10	98%	$200,000 - $400,000

Energy and Non-Air Quality Environmental Impacts: We do not anticipate significant energy or non-air quality environmental impacts resulting from capturing and ducting additional emissions to the existing SO_2 control system. Non-air quality impacts from venting additional captured emissions to the existing scrubber are not expected to be significant given that FMMI is already controlling much larger quantities of SO_2 in the existing scrubber and managing the wastewater and sludge that result.

Pollution Control Equipment in Use at the Source: SO_2 emissions collected from the electric furnace are ducted to the four-pass, double contact acid plant. There is a wet scrubber (the tailstack scrubber) located after the acid plant outlet, to which emissions may be vented "if needed." In addition, gases collected from the secondary collection system are ducted to the vent

[124] AP 42, Chapter 12.3, Primary Copper Smelters, Table 12.3-3 (cleaning furnace) and Table 12.3-11 (converter slag return).

fume scrubber, which is another wet scrubber. The vent fume scrubber also controls secondary emissions from the IsaSmelt and emissions collected from other equipment.

Remaining Useful Life: FMMI has not indicated any plans to remove the electric furnace from service.

Degree of Visibility Improvement: Our modeling results did not demonstrate even modest visibility improvements at any Class I areas from this option. Improvements were 0.004 dv or less at each Class I area, and only 0.008 dv for the cumulative sum over all areas. These are negligible visibility improvements over the baseline levels, as expected from the small emission reductions associated with this option.

c. BART Determination for Electric Furnace

Based on the high cost of compliance to upgrade the vent fume scrubber and low potential for visibility improvement, we are proposing that existing controls represent BART for SO_2 emissions from the electric furnace. While we would prefer to set a numeric emission limit in order to ensure that SO_2 emissions from the electric furnace do not increase in the future, such a limit is impracticable because emissions from the electric furnace are commingled with emissions from non-BART eligible units in the vent fume stack. Therefore, consistent with 40 CFR 51.308(e)(1) , we propose a work practice standard prohibiting active aeration of the electric furnace.

3. BART Analysis for NO_x from Process Heaters

NO_x emissions from the FMMI smelter result from the combustion of natural gas to heat process equipment. According to the Documentation Report accompanying AirControlNet, the cost to retrofit process heaters with low NO_x burners, which can reduce NO_x emissions by 50 percent, is $2,200 per ton.[125] Although this is not necessarily cost-prohibitive, there is relatively little potential for visibility improvement from installation of any NO_x controls at FMMI. In particular, the maximum modeled 98th percentile visibility impact resulting from baseline NO_x emissions from FMMI is 0.11 dv.[126] In addition, the WRAP estimated the annual BART-eligible NO_x emissions from the facility as 159 tons per year,[127] whereas we estimate annual BART-eligible NO_x baseline emissions as 38 tons per year. Therefore, the baseline visibility impact attributable to NO_x, and thus, the potential for visibility improvement due to NO_x reductions, is, in fact, significantly less than 0.11 dv. Given the small potential for visibility improvement, we propose that NO_x controls are not warranted for purposes of BART. However, in order to ensure that NO_x emissions do not increase in the future, we propose to set a 12-month rolling cap of 40 tons of NO_x from the subject-to-BART units, which is equivalent to the de minimis level of emissions set out in the RHR and is roughly equivalent to current annual emissions from these units.[128]

VI. EPA's Proposed Reasonable Progress Analyses and Determinations

Summary: In this section, EPA addresses point sources for NO_x, area sources for NO_x and SO_2, the reasonable progress goals for the Class I areas, and a demonstration that the rate of progress is reasonable compared to the URP. In our previous actions on the Arizona RH SIP, EPA narrowed the focus of the RP analysis to point sources of NO_x and area sources of NO_x and SO_2. Based on our analysis, we propose to require emissions reductions consistent with SNCR on Kiln 4 at the Phoenix Cement Clarkdale Plant and on Kiln 4 at the CalPortland Cement Rillito Plant. EPA proposes to find that it is not reasonable to require additional controls on area sources

[125] AirControlNet, Version 4.1, Documentation Report. Prepared by E.H. Pechan and Associates, Inc. for U.S. EPA, Office of Air Quality, Planning, and Standards. May, 2006, section III, page 445.
[126] Summary of WRAP RMC BART Modeling for Arizona, Draft Number 5, May 25, 2007, page 23.
[127] *Id.*
[128] 40 CFR 51.308(e)(1)(ii)(C).

of NO_x and SO_2 at this time. We are also proposing RPGs consistent with a combination of control measures that include the approved Arizona RH SIP measures as well as the finalized and proposed Arizona RH FIP measures. Finally, we propose to find that it is not reasonable for any of Arizona's Class I areas to meet the URP during this planning period, and demonstrate that rate of progress is reasonable based on our RP analysis.

Background: The RHR requires the State, or EPA in the case of a FIP, to set RPGs by considering four factors: "the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources" (collectively "the RP factors").[129] The RPGs must provide for an improvement in visibility on the worst days and ensure no degradation in visibility on the best days during the planning period. Furthermore, if the projected progress for the worst days is less than the Uniform Rate of Progress (URP), then the state or EPA must demonstrate, based on the factors above, that it is not reasonable to provide for a rate of progress consistent with the URP.[130]

In our final rule on the Arizona RH SIP published on July 30, 2013, we partially approved and partially disapproved the State's RP analysis.[131] In particular, we approved the State's decision to focus on NO_x and SO_2 sources and its decision not to require additional controls on non-BART point sources of SO_2 for this planning period. However, we disapproved the State's RPGs for the worst days and best days, as well as its RP analyses and determinations for point sources of NO_x as well as area sources of SO_2 and NO_x. Accordingly, we have analyzed these remaining source categories to determine whether additional controls are reasonable based on an evaluation of the RP factors.

[129] 40 CFR 51.308(d)(1)(i)(A).
[130] 40 CFR 51.308(d)(1)(ii).
[131] See 78 FR 46173 (codified at 40 CFR 52.145(g)).

A. Reasonable Progress Analysis of Point Sources for NO_x

EPA conducted an extensive statewide analysis of NO_x point sources to determine whether cost-effective controls on sources near Class I areas would contribute to visibility improvements. In this section, we describe the process to identify and analyze these potentially affected NO_x point sources for reasonable progress. Of the nine point sources evaluated for reasonable progress, EPA is proposing to require Phoenix Cement Clarkdale Plant and CalPortland Cement Rillito Plant to comply with new emissions limits for NO_x based on the analysis presented below and in the TSD available in the docket. We are seeking comment on our analyses and proposed determinations for all the identified sources.

1. Identification of NO_x Point Sources

To identify point sources in Arizona that potentially affect visibility in Class I areas, EPA examined the annual emissions data from the WRAP 2002 planning inventory and identified those sources with facility-wide actual emissions that exceed 250 tpy of NO_x or SO_2. For these sources, we calculated the total actual emission rate (Q) in tpy of NO_x and SO_2 and determined the distance (D) in kilometers of each source to its closest Class I area.[132] We employed a contractor to prepare an initial spreadsheet calculating these Q and D values.[133] We used a Q divided by D value of ten as a threshold for further evaluation of RP controls. We selected this value based on guidance contained in the BART Guidelines, which state:

> Based on our analyses, we believe that a State that has established 0.5 deciviews as a contribution threshold could reasonably exempt from the BART review process sources that emit less than 500 tpy of NO_x or SO_2 (or combined NO_x and SO_2), as long as these sources are located more than 50 kilometers from any Class I area; and sources that emit less than 1000 tpy of NO_x or SO_2 (or combined NO_x and SO_2) that are located more than 100 kilometers from any Class I area.[134]

[132] The analysis included NO_X, SO_2, and particulate matter pollutants because we had not yet approved ADEQ's determination to focus on NO_X and SO_2, nor had we approved its conclusion regarding non-BART SO_2 point sources, at the time this screening analysis was performed.
[133] "EP-D-07-102 WA5-12 Task4 Deliverable (AZ-BART-QbyD-Screening-report)-final.xlsx".
[134] See 40 CFR pt. 51, app. Y, § III (How to Identify Sources "Subject to BART").

The approach described above corresponds to a Q/D threshold of ten. In addition, the use of a Q/D threshold of ten or greater is recommended by the Federal Land Managers' Air Quality Related Values Work Group (FLAG) as a screening threshold, as described in the FLAG 2010 Phase I Report.[135] A summary of sources with a Q/D value greater than 10 is included in Table 39.

TABLE 39—SOURCES OF NO_X WITH Q/D VALUE GREATER THAN 10

Owner/Operator	Facility Name	Q (tpy)	D (km)	Q/D
Arizona Public Service	West Phoenix Plant	992	73.10	14
CalPortland Cement Co.	Rillito Plant	5,075	6.99	726
Arizona Electric Power Coop.	Apache Generating Station	11,840	44.86	264
Arizona Public Service	Cholla Power Plant	33,588	31.75	1058
Lhoist North America	Douglas Lime Plant	755	55.16	14
El Paso Natural Gas Co.	Tucson Compressor Station	336	14.72	23
El Paso Natural Gas Co.	Flagstaff Compressor Station	1,010	34.94	29
Tucson Electric Power	Sundt Generating Station	5,659	15.84	357
Lhoist North America	Nelson Lime Plant	2,556	24.56	104
Freeport-McMoRan	Miami Smelter	5,996	15.58	385
Phoenix Cement	Clarkdale Plant	2,744	12.65	217
Pima County	Ina Road Sewage Plant	258	12.56	21
ASARCO	Smelter and Mill	18,486	47.22	392
Salt River Project	Coronado Generating Station	29,674	48.53	611
Salt River Project	San Tan Generating Station	335	28.13	12
Catalyst Paper Abitibi	Snowflake Pulp Mill	5,143	39.36	131
Salt River Project	Aqua Fria Generating Station	994	68.87	14
Tucson Electric Power	Springerville Generating Station	32,434	60.46	536
El Paso Natural Gas Co.	Williams Compressor Station	1,373	19.12	72

Of the sources listed in Table 39, we eliminated several sources from further consideration by calculating updated Q/D values based on 2008-2010 emission data.[136] As a result, APS West Phoenix Plant, Lhoist Douglas Plant, SRP San Tan Generating Station, and

[135] Section 3.2, Initial Screening Criteria (New), Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase I Report—Revised (2010).
[136] See spreadsheet "10D Screening Update - 2008-10 Emission Data.xlsx" in the docket.

SRP Agua Fria Generating Station have Q/D values less than or equal to ten. Thus, we eliminated these sources from further consideration for this planning period. However, if any of these sources resume operations at levels sufficient to increase their Q/D value to ten or greater, Arizona should consider them for potential RP controls in the next planning period.

Finally, we eliminated from further consideration those sources (or units at sources) that were evaluated under BART. These include the Apache Generating Station, Coronado Generating Station, Cholla Power Plant (except Unit 1), Sundt Generating Station (except for Units 1-3), Snowflake Pulp and Paper Mill, and Nelson Lime Plant. Because the BART analysis examines many of the same factors as those evaluated for reasonable progress, we propose that the BART determinations for these facilities satisfy the requirement for reasonable progress from these facilities during this planning period. The final list of sources considered for reasonable progress NO_x controls is summarized in Table 40.

TABLE 40—SOURCES OF NO_X FOR REASONABLE PROGRESS ANALYSES

Owner/Operator	Facility Name	Notes
CalPortland Cement Co.	Rillito Plant	
Arizona Public Service	Cholla Power Plant (Unit 1)	Units 2-4 subject to BART
El Paso Natural Gas Co.	Tucson Compressor Station	
El Paso Natural Gas Co.	Flagstaff Compressor Station	
Tucson Electric Power	Sundt Generating Station (Units 1-3)	Unit 4 subject to BART
Phoenix Cement	Clarkdale Plant	
Pima County	Ina Road Sewage Plant	
Tucson Electric Power	Springerville Generating Station (Units 1-2)	Units 3-4 have SCR
El Paso Natural Gas Co.	Williams Compressor Station	

2. Analysis of Potentially Affected NO_x Point Sources

EPA contracted with the University of North Carolina (UNC) and their subcontractor, Andover Technology Partners (ATP), to perform RP analyses for the nine sources listed in Table 40. EPA considered the four RP factors for each of these sources based on the work from UNC. In addition, for the larger point sources (EGUs and cement kilns), we conducted CALPUFF modeling to assess the potential visibility benefits of controls.[137] These analyses are set out in the TSD and are summarized in the following sections.

a. Phoenix Cement Clarkdale Plant Kiln 4

Costs of Compliance: This facility consists of one precalciner kiln, which currently uses LNB for NO_x control. Our estimate of costs of compliance is based primarily on estimates provided by PCC in their March 6, 2013 comment letter, with revisions to certain cost items we considered to be unreasonable or not allowed by EPA's Control Cost Manual.[138] As explained in further detail in the TSD, we estimated a total annual cost for SNCR of approximately $940,000 per year. SNCR is estimated to reduce emissions at the kiln by 810 tpy at a cost of $1,142/ton, based on baseline emissions of 1620 tpy and a 50 percent SNCR control efficiency. As explained in the TSD, we are seeking comment on whether a different SNCR control efficiency is appropriate for this kiln. If we receive technical information demonstrating that a different SNCR control efficiency is appropriate for Kiln 4, we will incorporate this change into our analysis.

Time Necessary for Compliance: We expect that SNCR could be installed in approximately 3 years from the final date of this action. The Institute of Clean Air Companies estimates that the installation time for SNCR on industrial sources is 10-13 months.[139] CPCC estimates that it would require approximately three years to install SNCR on their similar technology kiln. Given these two pieces of information, a 3-year timeframe appears to be reasonable.

[137] While visibility is not an explicitly listed factor to consider when determining whether additional controls are reasonable, the purpose of the four-factor analysis is to determine what degree of progress toward natural visibility conditions is reasonable. Therefore, it is appropriate to consider the projected visibility benefit of the controls when determining if the controls are needed to make reasonable progress.

[138] Comments submitted on EPA’s December 21, 2012 proposed rulemaking partially approving and disapproving Arizona’s Regional Haze Plan. 77 FR 75704.

[139] Typical Installation Timelines for NOx Emissions Control Technologies on Industrial Sources, Institute of Clean Air Companies, December 4, 2006.

Energy and Non-Air Quality Environmental Impacts of Compliance: The installation and operation of SNCR at the plant would require a small increase in energy usage. The cost of this additional energy usage is included in the cost analysis. Non-air quality environmental impacts associated with SNCR include the hazards of transporting and storing urea or ammonia, especially if anhydrous ammonia is used. However, since the handling of anhydrous ammonia will involve the development of a risk management plan (RMP), we consider the associated safety issues to be manageable as long as established safety procedures are followed. Therefore, we find that these impacts are not sufficient to warrant eliminating SNCR as a control option.

Remaining Useful Life: EPA presumes that the kiln would continue operating for 20 years and fully amortize the cost of controls.

Degree of Improvement in Visibility: There are twelve Class I areas within 300 km of the Clarkdale Plant. As shown in Table 41, the highest 98th percentile baseline visibility impact of Phoenix Cement is 5.2 dv at Sycamore. Pine Mountain, Mazatzal, and the Grand Canyon all have visibility impacts over 0.5 dv, and other areas are at 0.1 dv or less. The cumulative sum of visibility impacts over all the Class I areas is 7.5 dv. The maximum visibility improvement due to SNCR is 1.9 dv at Sycamore, 0.3 dv at Pine Mountain, and slightly less at Mazatzal and the Grand Canyon. The cumulative improvement from SNCR is 3.0 dv.

TABLE 41—PHOENIX CEMENT KILN 4: VISIBILITY IMPACT AND IMPROVEMENT FROM NO_X CONTROLS

Class I Area	Distance (km)	Visibility Impact	Visibility Improvement
		Base Case (base)	SNCR -50% NO_x (ctrl2)
Bryce Canyon NP	296	0.09	0.04
Galiuro WA	278	0.03	0.01
Grand Canyon NP	133	0.51	0.25
Mazatzal WA	59	0.51	0.24

Mount Baldy WA	249	0.05	0.02
Petrified Forest NP	200	0.21	0.10
Pine Mountain WA	56	0.66	0.32
Saguaro NP	284	0.03	0.01
Sierra Ancha WA	142	0.09	0.04
Superstition WA	151	0.10	0.05
Sycamore Canyon WA	10	5.15	1.85
Zion NP	272	0.09	0.05
Cumulative (sum)		7.5	3.0
Maximum		5.15	1.85
# CIAs >= 0.5 dv		4	1
million $/dv (cumul. dv)			$0.3
million $/dv (max. dv)			$0.5

Phoenix Cement is only 10.5 km away from the Sycamore Canyon Wilderness. Therefore NO_x emitted by the Plant may not be fully converted to NO_2 by the time it reaches Sycamore Canyon and may not be fully available to form visibility-degrading particulate nitrate. However, the CALPUFF model assumes 100 percent conversion. EPA explored this issue by scaling back the visibility extinction due to NO_2 and nitrate to reflect lower NO-to-NO_2 conversion rates, described further in the TSD. As shown in Table 42, EPA found that visibility impacts and the improvement due to SNCR decrease along with the percent conversion assumed. However, the benefit of SNCR is 0.52 dv when NO conversion is reduced to 25 percent. Even for an unrealistically low assumption of 10 percent (i.e., no conversion of NO to NO_2 after the plume leaves the stack), the benefit of SNCR is 0.25 dv at Sycamore Canyon alone. Because the other Class I Areas are far enough way for NO_x emitted by the Plant to be fully converted to $NO_{2,}$ the benefits at the other Class I areas would remain the same.

TABLE 42—BENEFIT OF SNCR ON PHOENIX CEMENT AT SYCAMORE CANYON FOR VARIOUS NO-TO-NO_2 CONVERSION RATES

NO % Conversion	100%	75%	50%	25%	10%
Base case	5.14	4.19	3.13	1.94	1.17

SNCR	3.30	2.68	2.07	1.42	0.92
Benefit	1.85	1.51	1.06	0.52	0.25

Proposed RP Determination: Based on our analysis of the four RP factors, as well as the expected degree visibility improvement, EPA proposes to require compliance with an emission limit of 2.12 lb/ton on Kiln 4 based on a 30-day rolling average basis.[140] We propose to find that this emissions limit, equivalent to SNCR control, is cost-effective at $1,142/ton and would result in significant visibility benefits at Sycamore Canyon Wilderness Area. We are proposing to require compliance with the 2.12 lb/ton limit by December 31, 2018.

We are also soliciting comment on the possibility of establishing an annual cap on NO_x emissions from Kiln 4 in lieu of a lb/ton emission limit. Such a cap would provide additional flexibility to PCC by allowing them to comply either by installing controls or by limiting production. In particular, we are seeking comment on an annual NO_x emission cap for Kiln 4 of 810 tpy established on a rolling 12-month basis, effective December 31, 2018.

If production remains at current levels, PCC could meet this cap without installing any additional controls. However, if production increases to pre-2008 levels, we expect that PCC would need to install SNCR on Kiln 4 to comply with the cap.

b. CalPortland Cement Rillito Plant Kilns 1-4

The facility consists of three long dry kilns (Kilns 1-3) and one precalciner kiln (Kiln 4). Due to the significant differences between long dry kilns and precalciner kilns, we have separately analyzed Kilns 1-3 and Kiln 4.

1. Rillito Plant Kilns 1-3

[140] The basis for this specific emission rate is described in the TSD.

Kilns 1-3 have not operated since 2008 due to economic conditions. However, CPCC retains the ability to start using these kilns again at any time. Therefore, we conducted an analysis of the kilns using pre-2008 emission levels.

Costs of Compliance: Our estimate of the costs of compliance is based primarily on estimates provided by CalPortland in its RP analysis, with revisions to certain cost items we considered to be unreasonable or not allowed by EPA's Control Cost Manual.[141] Our analysis identified SNCR with Mixing Air Technology (MAT) as the most cost-effective control technology. Installation of SNCR with MAT on Kilns 1-3 is estimated to reduce emissions at each kiln by 182 tpy at a cost of $5,603/ton reduced, based on an annualized cost of approximately $1 million per year and 30-percent control efficiency for SNCR.[142]

Time Necessary for Compliance: CPCC estimates that the time needed to install the control equipment is about 3 years.

Energy and Non-Air Quality Environmental Impacts of Compliance: The installation and operation of SNCR at the plant would require a small increase in energy usage. The cost of this additional energy usage is included in the cost analysis. Non-air quality environmental impacts associated with SNCR include the hazards of transporting and storing urea or ammonia, especially if anhydrous ammonia is used. However, since the handling of anhydrous ammonia will involve the development of an RMP, we consider the associated safety issues to be manageable as long as established safety procedures are followed. Therefore, we find that these impacts are not sufficient to warrant eliminating SNCR as a control option.

Remaining Useful Life: The plant’s owner intends to shut down all four kilns and replace them with a new kiln that would be subject to Best Available Control Technology and a visibility

[141] “Reasonable Progress Analysis for CalPortland Company Rillito Cement Plant Kiln, prepared by CalPortland Company” Submitted to EPA May 9, 2013.
[142] See TSD for an analysis of all control options and associated control efficiencies and control costs.

impact analysis.[143] This project has been on hold while the economy in Arizona recovers. As a result, it is unclear whether these kilns will be in service long enough to fully amortize the cost of controls. However, because there is no enforceable shutdown date at this time, we assume that the kilns will remain in service for a 20-year amortization period.

Degree of Improvement in Visibility: The maximum visibility improvement due to SNCR on Kilns 1-3 is 0.22 dv at the eastern unit of Saguaro NP, 0.18 dv at Galiuro WA, and smaller for other areas. The cumulative visibility improvement is 0.7 dv.

TABLE 43—CALPORTLAND CEMENT KILNS 1-3 AND KILN 4: VISIBILITY IMPACT AND IMPROVEMENT FROM NO_X CONTROLS

Class I Area	Distance (km)	Visibility Impact	Visibility Improvement	
		Base Case (c0)	SNCR on Kilns 1,2,3 (c22)	SNCR on Kiln 4 (c24)
Chiricahua NM	171	0.25	0.05	0.06
Chiricahua WA	170	0.23	0.05	0.05
Galiuro WA	73	1.02	0.18	0.19
Gila WA	240	0.12	0.02	0.03
Mazatzal WA	171	0.13	0.02	0.03
Mount Baldy WA	223	0.11	0.03	0.03
Petrified Forest NP	290	0.11	0.02	0.03
Pine Mountain WA	213	0.11	0.02	0.02
Saguaro NP	8	1.26	0.22	0.24
Sierra Ancha WA	153	0.13	0.02	0.03
Superstition WA	108	0.30	0.06	0.06
Sycamore Canyon WA	287	0.09	0.02	0.02
Cumulative (sum)		3.9	0.7	0.8
Maximum		1.26	0.22	0.24
# CIAs >= 0.5 dv		2	0	0
million $/dv (cumul. dv)			$1.5	$1.4
million $/dv (max. dv)			$4.8	$4.6

The Saguaro NP results in this table are for the eastern unit of the park only.

[143] See Arizona RH SIP supplement, page 32.

Proposed RP Determination: Given the lack of emissions from Kilns 1-3 over the last five years and the relatively high cost of controls ($5,603/ton), EPA proposes to find that requiring controls for these units is not reasonable at this time.

2. Rillito Plant Kiln 4

Costs of Compliance: Our estimate of the costs of compliance is based primarily on estimates provided by CalPortland in its RP analysis, with revisions to certain cost items we considered to be unreasonable or not allowed by EPA's Control Cost Manual.[144] Our analysis identified the addition of SNCR to the existing LNB as the most cost-effective available control technology. As explained in further detail in the TSD, we estimated a total annual cost for SNCR of approximately $1.1 million per year. SNCR is estimated to reduce emissions by 1,041 tpy at a cost of $1,047/ton reduced, based on baseline emissions of 2,082 tons per year and a 50 percent SNCR control-efficiency. As explained in the TSD, we are seeking comment on whether a different SNCR control efficiency is appropriate for Kiln 4. If we receive technical information demonstrating that a different SNCR control efficiency is appropriate for Kiln 4, we will incorporate this change into our analysis.

Energy and Non-Air Quality Environmental Impacts of Compliance: The installation and operation of SNCR at the plant would require a small increase in energy usage. The cost of this additional energy usage is included in the cost analysis. Non-air quality environmental impacts associated with SNCR include the hazards of transporting and storing urea or ammonia, especially if anhydrous ammonia is used. However, since the handling of anhydrous ammonia will involve the development of an RMP, we consider the associated safety issues to be manageable as long as established safety procedures are followed. Therefore, we find that these impacts are not sufficient to warrant eliminating SNCR as a control option.

[144] "Reasonable Progress Analysis for CalPortland Company Rillito Cement Plant Kiln, prepared by CalPortland Company" Submitted to EPA May 9, 2013.

Existing Pollution Control Equipment: Kiln 4 is a precalciner kiln that currently uses LNB for NO_x control.

Remaining Useful Life: The plant's owner intends to shut down all four kilns and replace them with a new kiln that would be subject to Best Available Control Technology and a visibility impact analysis.[145] This project has been on hold while the economy in Arizona recovers. As a result, it is unclear whether these kilns will be in service long enough to fully amortize the cost of controls. However, because there is no enforceable shutdown date at this time, we assume that the kilns will remain in service for a 20-year amortization period.

Degree of Improvement in Visibility: As shown in Table 43, the maximum visibility improvement due to SNCR on Kiln 4 is 0.24 dv at the eastern unit of Saguaro NP, 0.19 dv at Galiuro WA, and smaller for other areas. The cumulative visibility improvement is 0.8 dv. The cumulative visibility improvement from SNCR on all four kilns would be about 1.5 dv.

As discussed above in the section covering visibility improvements for TEP Sundt, EPA remodeled impacts at Saguaro NP to address both the eastern and western units of the park. The modeled visibility impact at the western unit of Saguaro, not shown in the table, is 6.04 dv, far greater than at the eastern unit. The modeled improvement there due to SNCR is 0.30 dv, still rather modest but 25 percent greater than for the eastern unit. However, CalPortland is only 7.8 km away from the western unit, so its emitted NO_x may not be fully converted to NO_2 by the time it reaches there, as is assumed in the CALPUFF model. It thus may not be fully available to form visibility-degrading particulate nitrate. EPA explored this issue by scaling back the visibility extinction due to NO_2 and nitrate to reflect lower NO-to-NO_2 conversion rates, described further in the TSD. EPA found that visibility impacts and the improvement due to SNCR decrease along with the percent conversion assumed, so much so that at a 25 percent

[145] See Arizona RH SIP supplement, page 32.

conversion rate, the SNCR benefit was only 0.05 dv. Therefore, EPA is relying on impacts and improvements for the more distant eastern unit of Saguaro NP.

Proposed RP Determination: EPA finds that SNCR is cost-effective for Kiln 4 at $1,047/ton, would not result in undue non-air quality environmental impacts, and would result in modest visibility benefits at Saguaro NP and Galiuro WA. Therefore, we propose to determine that it is reasonable to require SNCR at Kiln 4. In particular, EPA proposes to require compliance with an emissions limit of 2.67 lb/ton at Kiln 4 based on a 30-day rolling average by December 31, 2018.[146] We are also soliciting comment on the possibility of requiring an annual cap on NO_x emissions in lieu of a lb/ton emission limit. In order to avoid a shift in production from Kiln 4 to Kilns 1-3, we are proposing that the cap would apply to all four kilns. In particular, we are seeking comment on an annual NO_x emission cap for Kilns 1-4 of 2,082 tpy, established on a rolling 12-month basis. CPCC could meet this cap either by retaining production at current levels, or by increasing production and installing SNCR on Kiln 4. We are proposing to require compliance with this rolling 12-month limit by December 31, 2018.

c. APS Cholla Unit 1

Costs of Compliance: Unit 1 is a 1,246 MMBtu/hr tangential coal-fired boiler, which currently employs LNB with separated overfire air (SOFA) for NO_x control. EPA identified two feasible additional controls: SNCR and SCR. The estimated emission reductions and costs for these two options are summarized in Tables 44 and 45.

TABLE 44—CHOLLA UNIT 1: NO_X EMISSION ESTIMATES

Control Option	NO_x Emissions			Emission Reduction
	(lb/MMBtu)	(lb/hr)	(tpy)	(tpy)
Baseline (LNB+OFA)	0.22	274	1,032	--

[146] See TSD for a discussion of how this emission limit was calculated.

SNCR	0.15	192	723	310
SCR	0.05	62	235	798

TABLE 45—CHOLLA UNIT 1: NO_X CONTROL COST ESTIMATES

Control Option	Total Capital Cost	Annualized Capital Cost	Annual O&M Costs	Total Annual Cost	Cost-Effectiveness ($/ton)	
	($)	($)	($)	($)	Ave	Incr
Baseline (LNB+OFA)	--	--	--	--	--	--
SNCR	$2,272,000	$241,725	$918,875	$1,160,599	$3,748	--
SCR	$26,437,190	$2,812,730	$1,425,137	$4,237,867	$5,313	$6,307

Time Necessary for Compliance: Given the estimate from the Institute of Clean Air Companies[147] that about a year is required to install SNCR, and the estimate of three years for installing SNCR on a cement kiln discussed previously in this notice, EPA estimates that SNCR could be installed in less than three years. In our previous Arizona FIP action, EPA estimated that 5 years would be required to install SCR on coal-fired boilers.[148] That estimate also holds for this source.

Energy and Non-Air Quality Environmental Impacts of Compliance: SCR and SNCR can result in additional ammonia emissions. There is also increased truck traffic bringing the reagent on site. SCR will also slightly reduce the efficiency of the plant, resulting in increased fuel usage.

Remaining Useful Life: EPA assumes that this plant would continue operating for 20 years and fully amortize the cost of controls.

Degree of Improvement in Visibility: CALPUFF modeling indicates that installation of SNCR at Unit 1 would provide a 0.10 dv visibility benefit at the most affected Class I area,

[147] Typical Installation Timelines for NOx Emissions Control Technologies on Industrial Sources, Institute of Clean Air Companies, December 4, 2006.
[148] See 77 FR 42834 at 42865 for more details.

Petrified Forest NP, while installation of SCR would provide a 0.20 dv benefit at the same area as shown in Table 46. Note that all of these results, including the base case, assume that SCR has been applied to Units 2, 3 and 4, consistent with EPA's previous BART determination for those units.

TABLE 46—CHOLLA UNIT 1: VISIBILITY IMPACT AND IMPROVEMENT FROM NO_X CONTROLS

Class I Area	Distance (km)	Visibility Impact	Visibility Improvement from Control	
		Base Case (ctrl0/ctrl2_r2)	SNCR on Unit 1 (ctrl2-1)	SCR on Unit 1 (ctrl2-2)
Capitol Reef NP	300	0.71	0.04	0.09
Galiuro WA	249	0.30	0.01	0.01
Gila WA	222	0.48	0.01	0.01
Grand Canyon NP	179	1.14	0.05	0.12
Mazatzal WA	128	0.79	0.02	0.04
Mesa Verde NP	292	0.65	0.03	0.06
Mount Baldy WA	128	0.71	0.01	0.02
Petrified Forest NP	39	3.38	0.10	0.20
Pine Mountain WA	149	0.55	0.01	0.03
Saguaro NP	300	0.23	0.00	0.00
Sierra Ancha WA	126	0.87	0.02	0.06
Superstition WA	166	0.81	0.03	0.06
Sycamore Canyon WA	147	0.76	0.03	0.07
Cumulative (sum)		11.4	0.3	0.7
Maximum		3.38	0.10	0.20

Proposed Determination: EPA proposes to determine that it is not reasonable to require additional controls on this facility at this time. The costs for both SNCR and SCR are relatively high in light of the relatively small anticipated visibility benefits of the controls. However, this decision should be revisited in future planning periods.

d. El Paso Natural Gas Company's Tucson Compressor Station

Costs of Compliance: This site includes seventeen 1,071 hp compressor engines. EPA's analysis indicates that the most cost-effective control would be an air/fuel ratio controller that would reduce emissions by 578 tpy at a cost of $792/ton.[149]

The site also includes four 370 hp engines. EPA's analysis indicates that the most cost-effective control would be a three-way catalyst that would reduce emissions by 96 tons per year at a cost of $290/ton.

Time Necessary for Compliance: The Institute of Clean Air Companies estimates that 8 to 14 weeks would be required to install these kinds of controls.[150]

Energy and Non-Air Quality Environmental Impacts of Compliance: Both controls may increase fuel usage by reducing the thermal efficiency of the engines.

Remaining Useful Life: EPA assumes that the engines would continue operating for 20 years and fully amortize the cost of controls.

Proposed Determination: EPA proposes to find that it is not reasonable to require additional controls on this facility at this time. Natural gas engines similar to those at the Tucson Compressor Station are found in various locations throughout Arizona. EPA's assessment indicates that a state-wide or regional approach to controlling this source category could result in significant emissions reductions. Given the dispersed nature of these engines, it is not practical for EPA to control these sources. Therefore, EPA proposes to find that it is not reasonable to require additional controls on this particular source at this time. This source category should be given serious consideration for future planning periods, as it would be more appropriately controlled by the State.

e. El Paso Natural Gas Company's Flagstaff Compressor Station

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[149] See spreadsheet "Non EGU_RP_Ch5.xlsx" in the docket.

[150] Typical Installation Timelines for NO_x Emissions Control Technologies on Industrial Sources, Institute of Clean Air Companies, December 4, 2006.

Costs of Compliance: This site includes two 5,500 hp compressor engines. EPA's analysis indicates that the most cost-effective control would be an air/fuel ratio controller that would reduce emissions by 398 tpy at a cost of $432/ton. [151]

Time Necessary for Compliance: The Institute of Clean Air Companies estimates that 8 to 14 weeks would be required to install these kinds of controls.[152]

Energy and Non-Air Quality Environmental Impacts of Compliance: The controls may increase fuel usage by reducing the thermal efficiency of the engines.

Remaining Useful Life: EPA assumes that the engines would continue operating for 20 years and fully amortize the cost of controls.

Proposed RP Determination: EPA proposes to find that it is not reasonable to require additional controls on this facility at this time. Natural gas engines similar to those comprising the Flagstaff Compressor Station are found in various locations throughout Arizona. EPA's assessment indicates that a state-wide or regional approach to controlling this source category could result in significant emissions reductions. Given the dispersed nature of these engines, many of which may fall into the area source category discussed above, it is not practical for EPA to control these sources. Therefore, EPA proposes to find that it is not reasonable to require additional controls on this particular source at this time. This source category should be given serious consideration for future planning periods.

f. Tucson Electric Power Sundt Station (Units 1 – 3)

Costs of Compliance: TEP Sundt has three natural gas-fired boilers rated at approximately 1,220 MMBTU/hr each. EPA's analysis indicates that the most cost-effective control would be ultra-low NO_x burners (ULNB). This retrofit would reduce emissions from Unit

[151] See spreadsheet "Non EGU_RP_Ch5.xlsx" in the docket.
[152] Typical Installation Timelines for NO_x Emissions Control Technologies on Industrial Sources, Institute of Clean Air Companies, December 4, 2006.

1 by 46 tpy at a cost of $8,300/ton. It would reduce emissions from Unit 2 by 55 tpy at a cost of $7,000/ton. The retrofit would reduce emissions from Unit 3 by 90 tpy at a cost of $4,400/ton. As shown in Table 47, modeling indicates that these controls would provide a 0.40 dv visibility benefit at the most improved Class I area.

Time Necessary for Compliance: The Institute of Clean Air Companies estimates that 6 to 8 months would be required to install these kinds of controls.[153]

Energy and Non-Air Quality Environmental Impacts of Compliance: The ultra-low-NO_x burners may reduce the thermodynamic efficiency of the boilers and require an increase in fuel consumption.

Remaining Useful Life: EPA assumes that the boilers would continue operating for 20 years and fully amortize the cost of controls.

Proposed RP Determination: EPA proposes to find that it is not reasonable to require additional controls on this facility at this time. As noted above, ULNB has cost-effectiveness values for Sundt Units 1-3 in the range of $4,000 to 7,000 per ton. These costs are relatively high in light of the anticipated visibility benefits of the controls. However, this decision should be revisited in future planning periods, particularly if these units operate at a higher capacity factor in the future.

Degree of Improvement in Visibility: Modeling indicates that installation of ULNB on all three units would provide a 0.40 dv visibility benefit at the most improved Class I area, Saguaro National Park, as shown in Table 47. Note that all of these results assume that SNCR has been applied to Sundt Unit 4, consistent with EPA's previous BART determination for that unit. The

[153] Typical Installation Timelines for NO_x Emissions Control Technologies on Industrial Sources, Institute of Clean Air Companies, December 4, 2006.

visibility cost-effectiveness values are based on an annualized cost of $1.2 million per year, based on the analysis by UNC, contractor to EPA.[154]

TABLE 47—SUNDT UNIT 1, 2 AND 3: VISIBILITY IMPACT AND IMPROVEMENT FROM NO_X CONTROLS

Class I Area	Distance (km)	Visibility Impact	Visibility Improvement from Control
		Base Case (SNCR on Unit 4)	ULNB
Chiricahua NM	144	0.43	0.08
Chiricahua WA	141	0.51	0.07
Galiuro WA	64	1.10	0.22
Gila WA	232	0.17	0.02
Mazatzal WA	203	0.19	0.02
Mount Baldy WA	232	0.15	0.02
Pine Mountain WA	247	0.15	0.01
Saguaro NP	17	3.40	0.40
Sierra Ancha WA	178	0.19	0.02
Superstition WA	137	0.32	0.04
Cumulative (sum)		6.6	0.9
Maximum		3.40	0.40
# CIAs >= 0.5 dv		3	0
million $/dv (cumul. dv)			$1.3
million $/dv (max. dv)			$2.9

g. Ina Road Sewage Plant

Costs of Compliance: This site has seven 1,000 hp natural gas-fired internal combustion engines. EPA's analysis indicates that the most cost-effective control is non-selective catalytic

[154] Technical Analysis for Arizona and Hawaii Regional Haze FIPs: Task 9: Five-Factor RP Analyses for TEP Springerville, APS Cholla, TEP Sundt, CalPortland Cement and Phoenix Cement Plants, Contract No. EP-D-07-102, Work Assignment 5-12; Prepared for EPA Region 9 by University of North Carolina at Chapel Hill, ICF International, and Andover Technology Partners; October 3, 2012, Table 20.

reduction (NSCR). Installation of this control would reduce emissions by 1,029 tpy at a cost of $210/ton.[155]

Time Necessary for Compliance: The Institute of Clean Air Companies estimates that 8 to 14 weeks would be required to install these kinds of controls.[156]

Energy and Non-Air Quality Environmental Impacts of Compliance: The control measure may decrease the thermodynamic efficiency of the engines and increase fuel usage.

Remaining Useful Life: EPA assumes that the engines would continue operating for 20 years and fully amortize the cost of controls.

Proposed RP Determination: EPA proposes to find that it is not reasonable to require additional controls on this facility at this time. Natural gas engines similar to those at the Ina Road Sewage Plant are found in many locations throughout Arizona. EPA's assessment indicates that a state-wide or regional approach to controlling this source category could result in significant emissions reductions. Given the dispersed nature of these engines, many of which may fall into the area source category discussed above, it is not practical for EPA to control these sources. Therefore, EPA proposes to find that it is not reasonable to require additional controls on this particular source at this time. This source category should be given serious consideration for future planning periods, as it would be more appropriately controlled by the State.

h. Tucson Electric Power Springerville Plant

Costs of Compliance: TEP Springerville Plant Units 1 and 2 are 4,700 MMBtu/hr tangential coal-fired boilers, which currently employ LNB with OFA for NO_x control. EPA identified two feasible additional controls: SNCR and SCR. The estimated emission reductions and costs for these two options are summarized in Tables 48 and 49.

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[155] See spreadsheet "Non EGU_RP_Ch5.xlsx" in the docket.

[156] Typical Installation Timelines for NO_x Emissions Control Technologies on Industrial Sources, Institute of Clean Air Companies, December 4, 2006.

TABLE 48—TEP SPRINGERVILLE 1 AND 2: NO_X EMISSION ESTIMATES

Control Option	NO_x Emissions			Emission Reduction
	lb/MMBtu	lb/hr	tpy	tpy
Springerville 1				
Baseline (LNB+OFA)	0.18	769	2,189	--
SNCR	0.13	538	1532	657
SCR	0.05	212	605	1,584
Springerville 2				
Baseline (LNB+OFA)	0.19	798	2,448	--
SNCR	0.13	559	1714	734
SCR	0.05	210	644	1,804

TABLE 49—TEP SPRINGERVILLE 1 AND 2: NO_X CONTROL COST ESTIMATES

Control Option	Total Capital Cost	Annualized Capital Cost	Annual O&M Costs	Total Annual Cost	Cost-Effectiveness ($/ton)	
	$	$/yr	$/yr	$/yr	Ave	Incr
Springerville 1						
Baseline (LNB+OFA)	--	--	--	--	--	--
SNCR	$8,496,000	$903,914	$1,933,059	$2,836,973	$4,320	--
SCR	$71,796,257	$7,638,614	$3,181,809	$10,820,423	$6,829	$8,606
Springerville 2						
Baseline (LNB+OFA)	--	--	--	--	--	--
SNCR	$8,496,000	$903,914	$2,141,291	$3,045,205	$4,146	--
SCR	$71,402,351	$7,596,705	$3,379,514	$10,976,219	$6,085	$7,416

Time Necessary for Compliance: Given the estimate from the Institute of Clean Air Companies[157] that approximately a year is required to install SNCR and the estimate of three years for installing SNCR on a cement kiln discussed previously in this notice. EPA estimates that SNCR could be installed in less than three years. In our previous Arizona FIP action, EPA

[157] Typical Installation Timelines for NO_x Emissions Control Technologies on Industrial Sources, Institute of Clean Air Companies, December 4, 2006.

estimated that 5 years would be required to install SCR on coal-fired boilers.[158] That estimate also holds for this source.

Energy and Non-Air Quality Environmental Impacts of Compliance: SCR and SNCR can result in additional ammonia emissions. There is also increased truck traffic bringing the reagent on site. SCR will also slightly reduce the efficiency of the plant, resulting in increased fuel usage.

Remaining Useful Life: EPA assumes that this plant would continue operating for 20 years and fully amortize the cost of controls.

Degree of Improvement in Visibility: As shown in Table 50, CALPUFF modeling indicates that SNCR at Units 1 and 2 would provide a 0.18 dv visibility benefit at the most affected Class I area and a cumulative 0.8 dv benefit across all affected areas. SCR would provide a 0.41 dv benefit at the most affected Class I area and cumulative 1.7 dv across all affected areas.

TABLE 50—SPRINGERVILLE UNITS 1 & 2: VISIBILITY IMPACT AND IMPROVEMENT FROM NO_X CONTROLS

Class I Area	Distance (km)	Impact	Improvement from Control	
		Base Case	SNCR (ctrl-1)	SCR (ctrl-2)
Bandelier NM	298	1.08	0.07	0.13
Chiricahua NM	253	0.85	0.07	0.14
Chiricahua WA.	264	0.88	0.00	0.01
Galiuro WA	211	0.95	0.03	0.08
Gila WA	111	4.39	0.18	0.41
Grand Canyon NP	302	0.79	0.07	0.07
Mazatzal WA	209	0.86	0.01	0.01
Mount Baldy WA	51	3.63	0.13	0.32
Petrified Forest NP	79	2.46	0.06	0.09
Pine Mountain Wa	236	0.67	0.02	0.06
Saguaro NP	263	0.57	0.01	0.04
San Pedro Parks WA	281	1.53	0.05	0.23

[158] See 77 FR 42834 at 42865 for more details.

Sierra Ancha Wa	165	1.01	0.02	0.05
Superstition WA	194	0.52	0.03	0.06
Sycamore Canyon WA	263	0.65	0.02	0.04
Cumulative (sum)		20.8	0.8	1.7
Maximum		4.39	0.18	0.41
# CIAs >= 0.5 dv		15	0	0
million $/dv (cumul. dv)			$7.3	$12.6
million $/dv (max. dv)			$32.2	$53.4

Proposed RP Determination: EPA proposes to determine that it is not reasonable to require additional controls at Springerville Units 1 and 2 at this time. While the cost per ton for SNCR may be reasonable, the projected visibility benefits are relatively small (0.18 dv at the most affected area). The projected visibility benefits of SCR are larger (0.41 dv at the most affected area), but we do not consider them sufficient to warrant the relatively high cost of controls for purposes of RP in this planning period. However, these units should be considered for additional NO_x controls in future planning periods.

i. El Paso Natural Gas Williams Compressor Station

Costs of Compliance: This site consists of five 2,500 hp engines, one 3,400 hp engine, and one 32,200 hp gas turbine. EPA's analysis indicates that air/fuel ratio controllers are the most cost-effective controls for the five 2,500 hp engines and would reduce emissions by 288 tpy at a cost of $547/ton. Our analysis indicates that an air/fuel ratio controller is also the most cost-effective control for the 3,400 hp engine and would reduce emissions from that engine by 131 tpy at a cost of $444/ton. Our analysis further indicates that water injection would be the most cost-effective control for the gas turbine and would reduce emissions from that engine by 505 tpy at a cost of $854/ton. [159]

[159] See spreadsheet "Non EGU_RP_Ch5.xlsx" in the docket.

Time Necessary for Compliance: The Institute of Clean Air Companies estimates that 8 to 14 weeks would be required to install these kinds of controls.[160]

Energy and Non-Air Quality Environmental Impacts of Compliance: These controls may increase fuel usage by reducing the thermal efficiency of the engines.

Remaining Useful Life: EPA assumes that the engines would continue operating for 20 years and fully amortize the cost of controls.

Proposed RP Determination: EPA proposes to find that it is not reasonable to require additional controls on this facility at this time. Natural gas engines similar to those comprising the Williams Compressor Station are found in various locations throughout Arizona. EPA's assessment indicates that a state-wide or regional approach to controlling this source could result in significant emissions reductions. Given the dispersed nature of these engines, many of which may fall into the area source category discussed above, it is not practical for EPA to control these sources. Therefore, EPA proposes to find that it is not reasonable to require additional controls on this particular source at this time. This source category should be given serious consideration for future planning periods, as it would be more appropriately controlled by the State.

B. Reasonable Progress Analysis of Area Sources for NO_x and SO_2

1. Identification of Area Sources of SO_2 and NO_x

The initial step in our area source RP analysis was the identification of specific SO_2 and NO_x area source categories to evaluate for potential controls. To that end, we examined data from the 2008 National Emissions Inventory (NEI) to determine the most significant area sources of SO_2 and NO_x. This analysis is described in the TSD, and the results are summarized in Tables 51 and 52. As discussed in the TSD, there are significant uncertainties in the area source

[160] Typical Installation Timelines for NO_x Emissions Control Technologies on Industrial Sources, Institute of Clean Air Companies, December 4, 2006.

emissions inventory for Arizona. In spite of the uncertainty, it is evident that the primary area source categories of most concern are Industrial and Commercial Boilers and Internal Combustion Engines burning distillate fuel oil. A third category, Residential Natural Gas Combustion, also comprises a significant portion of NO_x emissions. EPA has therefore identified these categories as "potentially affected sources." EPA proposes to find that the remaining source categories comprise too small of a percentage contribution to overall emissions to justify consideration for additional controls in this initial planning period.

TABLE 51—SIGNIFICANT AREA SOURCES OF NO_X IN ARIZONA

Source Type	Source Classification Code	Tons per Year (2008)	Portion of Total Area Source Emissions	Cumulative Portion
Industrial Boilers and Internal Combustion Engines (burning distillate fuel oil)	2102004000	2,300	29.3%	29.3%
Residential Natural Gas Combustion	2104006000	1,645.7	20.2%	49.5%
Industrial Natural Gas Combustion	2102006000	765.4	9.4%	58.8%
Open Burning, Land Clearing Debris		727.0	8.9%	67.7%

TABLE 52—SIGNIFICANT AREA SOURCES OF SO_2 IN ARIZONA

Source Type	Source Classification Code	Tons per Year (2008)	Portion of Total Area Source Emissions	Cumulative Portion
Industrial Boilers and Internal Combustion Engines (burning distillate fuel oil)	2102004000	1652.1	65.3%	65.3%
Commercial and Institutional Boilers and Internal Combustion Engines (burning distillate fuel oil)	2103004000	483.5	19.1%	84.5%
Industrial processes not elsewhere classified	2399000000	110.4	4.4%	88.8%

2. Analysis of Significant Area Source Categories

a. Approach to Area Source Analysis

In conducting an RP analysis for area source, EPA encountered significant limitations on the availability and accuracy of data concerning the relevant source categories. For purposes of emission inventory development, an area source is not a single facility, but a category of polluting sources known to exist within a certain geographic area (such as a county), whose actual number, age, and design is not known. The emissions from area sources are usually estimated based on a "top-down" method, where a surrogate piece of information, such as the number of people living in a county or the gallons of diesel fuel sold there in a given year, is used to estimate emissions. Each of the source categories analyzed has an emissions estimate derived from Federal, state, or local databases of fuel consumption. In the aggregate, these numbers are sufficiently accurate for most analyses. However, they do not provide adequate detail for EPA to precisely estimate the actual costs and benefits of controlling the existing population of sources.

Given these limitations in available data, EPA's analyses of area sources are limited in scope. For each category we have developed ranges for the estimated cost of compliance and general information about each of the other factors, based largely on data from three sources: the WRAP Four-Factor Analysis report,[161] EPA's Control Strategy Tool, and the documentation for EPA's AirControlNet tool.[162] The WRAP report lists several possible NO_x and SO_2 controls for industrial boilers and internal combustion engines, depending on their size and pre-existing controls. The WRAP report also addresses the other mandatory factors for an RP analysis. The Control Strategy Tool is EPA's most current tool for assessing the cost-effectiveness of control strategies for various source categories. EPA used this tool to confirm that the cost estimates in the WRAP report are still reasonable.[163] We also consulted the AirControlNet documentation

[161] "Supplementary Information for Four Factor Analyses by WRAP States," EC/R Incorporated, corrected version, April 20, 2010.
[162] "AirControlNet, Version 4.1," May 2006, E.H. Pechan and Associates.
[163] See spreadsheet titled "AZ FIP Cost Analysis_for Greg Nudd Rg 9_2013-08-13.xls".

report that contains the most current data on the cost-effectiveness of NO_x controls for residential natural gas combustion. Finally, while we lacked sufficient data to conduct visibility modeling for particular categories of area sources, we have analyzed the overall contribution of area sources to nitrate and sulfate-caused visibility impairment in Arizona's Class I areas in order to estimate the potential benefits of controls. The results of this analysis are provided below, following the results of the four-factor analyses for all of the source categories.

b. RP Analysis of Industrial, Commercial, and Institutional Boilers Burning Distillate Fuel Oil

Cost of Compliance: The estimated cost-effectiveness values for NO_x control options are:

- LNB: $400-7,000/ton;
- LNB/OFA: $400-7,000/ton;
- SNCR: $400-6,900/ton;
- SCR: $1,000-8,000/ton.

The estimated cost-effectiveness values for SO_2 control options for this category are:

- DSI: $5,000-11,000/ton;
- Wet FGD: $6,000-13,000/ton.

Time Necessary for Compliance: Installation of the control devices, in most cases, should take no more than 2-3 years. The only possible exception may be for installation of SCR, which may take as long as 5 years.

Energy and Non-Air Quality Environmental Impacts of Compliance: LNB may reduce combustion efficiency and slightly increase fuel consumption; SNCR and SCR would require some electricity use and environmental impacts from ammonia slip and transport and storage of the reagent. Wet FGD requires large quantities of water and requires disposal of wet ash.

Remaining Useful Life: It is reasonable to assume that the units would remain in use long enough to fully recover the costs of controls.

c. RP Analysis of Industrial, Commercial, and Institutional Internal Combustion Engines Burning Distillate Fuel Oil

Costs of Compliance: We estimate the following cost-effectiveness values for NO_x control options:

- Ignition timing retard: $1,000-2,200/ton;
- Exhaust Gas Recirculation: $780-2,000/ton;
- SCR: $3,000-7,700/ton;
- Replacement with Tier 4 engines: $900-2,400/ton.

We did not identify any technically feasible options for SO_2 control other than lower sulfur fuel.

Time Necessary for Compliance: Installation of the control devices, in most cases, should take no more than 2-3 years. The only possible exception may be for installation of SCR, which may take as long as 5 years.

Energy and Non-Air Quality Environmental Impacts of Compliance: SCR would require some electricity use and there may also environmental impacts from ammonia slip and transport and storage of the reagent. The other options would not have negative energy or non-air quality environmental impacts.

Remaining Useful Life: It is reasonable to assume that the units would remain in use long enough to fully recover the costs of controls.

d. RP Analysis of Residential Natural Gas Combustion

Costs of Compliance: We estimate the following cost-effectiveness values for NO_x control options:

- Replace space heaters with Low NO_x equivalent: $1,600/ton;

- Replace water heaters with Low NO_x equivalent: $1,230/ton. [164]

SO_2 controls are not needed for this category due to low sulfur content of pipeline natural gas.

Time Necessary for Compliance: Installation of the new devices, in most cases, should take no more than 2-3 years.

Energy and Non-Air Quality Environmental Impacts of Compliance: We did not identify any energy or non-air quality environmental impacts.

Remaining Useful Life: This factor is not applicable for a unit replacement.

Visibility Significance of Area Sources: As explained above, we do not have sufficient information to assess the likely visibility benefits of requiring controls on particular categories of area sources. However, in order to estimate the total potential visibility benefits that might result from controlling NO_x and SO_2 emissions from area sources, we have analyzed the overall contribution of area sources to nitrate- or sulfate-caused visibility impairment in Arizona's Class I areas. The relative contribution can be estimated by reviewing the results of the Particulate Source Apportionment Technology (PSAT) modeling conducted by the WRAP. This method and our evaluation of it are described in the WRAP TSD prepared by EPA.[165] Tables 53 and 54 below compare the contribution of Arizona area sources to visibility impairment in Arizona's Class I areas with the contributions from point and mobile sources.[166] Table 53 shows the relative contribution of these Arizona source categories to the 2018 predicted total nitrate impairment at the Class I areas. Table 54 shows the same data for 2018 predicted total sulfate impairment. Nitrate and sulfate comprise a subset of the total visibility impairment at these Class I areas. To calculate the source category's total contribution to visibility impairment, one would have to account for the other pollutants (such as coarse mass, black carbon, etc.). EPA has not

[164] Both estimates from AirControlNet Manual p. III-90 and are in 1990 dollars.
[165] "Technical Support Document for Technical Products Prepared by the Western Regional Air Partnership (WRAP) in Support of Western Regional Haze Plans," February 28, 2011.
[166] See http://vista.cira.colostate.edu/tss/Results/HazePlanning.aspx, select "Emissions and Source Apportionment" and the 2018 Base Case (base 18b) emissions scenario.

made that calculation here, as we are looking specifically at nitrate and sulfate impairment for this RP analysis.

TABLE 53 – 2018 PROJECTED NITRATE IMPAIRMENT: COMPARISON OF ARIZONA SOURCE CATEGORIES

Class I Area	Arizona Area Sources	Arizona Point Sources	Arizona Mobile Sources
CHIR1	0.7%	5.1%	5.1%
GRCA2	2.9%	7.4%	18.3%
IKBA1	4.1%	12.3%	23.6%
BALD1	0.8%	18.1%	8.7%
PEFO1	1.7%	26.7%	14.2%
SAGU1	5.2%	19.3%	27.5%
SAWE1	4.3%	18.4%	23.5%
SIAN1	4.1%	5.0%	20.7%
TONT1	5.4%	12.7%	30.2%
SYCA1	2.7%	14.0%	19.3%

TABLE 54 – 2018 PROJECTED SULFATE IMPAIRMENT: COMPARISON OF ARIZONA SOURCE CATEGORIES

Class I Area	Arizona Area Sources	Arizona Point Sources	Arizona Mobile Sources
CHIR1	0.4%	4.7%	0.5%
GRCA2	0.4%	4.3%	1.0%
IKBA1	1.0%	6.7%	1.2%
BALD1	0.7%	11.3%	0.7%
PEFO1	0.7%	19.6%	0.9%
SAGU1	2.1%	10.2%	1.7%
SAWE1	1.7%	9.6%	1.4%
SIAN1	0.8%	7.8%	1.1%
TONT1	1.3%	7.8%	2.8%
SYCA1	1.0%	3.5%	0.8%

As indicated in Tables 53 and 54, area sources in Arizona currently comprise a relatively small portion of the visibility impairment due to nitrate and sulfate, so the potential visibility benefits of NO_x or SO_2 controls on these sources would be relatively small at this point in time. However, the relative contribution of area sources to visibility impairment at Arizona's Class I areas may increase over time, as additional point source and mobile source controls are implemented. Therefore, additional analysis of these sources will be necessary in future planning periods.

f. Proposed RP Determination for Area Sources

EPA proposes to find that it is not reasonable to require additional controls on area sources of NO_x and SO_2 at this time. There are significant uncertainties about the costs and potential benefits of such rules at this time. Furthermore, the visibility benefits due to area source controls are likely to be much smaller than the significant reductions in SO_2 and NO_x emissions from point sources achieved during this planning period. We also note that no other Regional Haze SIP or FIP has imposed controls on such sources primarily to ensure reasonable progress.[167] EPA will work with the State and the relevant regional planning organizations to improve our understanding of the nature of these area source emissions, the costs and methods of controlling them, and their impact on visibility at Class I areas. Based on the results of these efforts, these source categories should be carefully considered in future Regional Haze SIPs.

C. Reasonable Progress Goals

We are proposing reasonable progress goals (RPGs) that are consistent with the combination of control measures included in the Arizona RH SIP measures that we previously approved; [168] the partial RH FIP that we promulgated on December 5, 2012; [169] and the partial RH FIP we are proposing today. In total, these final and proposed controls to meet the BART and RP requirements will result in higher emissions reductions and commensurate visibility improvements beyond what was in the State's plan. As a result, we expect that the visibility

[167] The Colorado Regional Haze SIP includes rules limiting emissions from certain Reciprocating Internal Combustion Engines. 77 FR 18052, 18089. However these rules are part of a State regulation intended to control ozone rather than regional haze. Colorado Air Quality Control Commission, Regulation Number 7, 5 CCR 1001-9, Control of Ozone via Ozone Precursors, Section XVII, Statewide Control for Oil and Gas Operations and Natural Gas-Fired Reciprocating Internal Combustion Engines, subsection E.3.a, (Regional Haze SIP) Rich Burn Reciprocating Internal Combustion Engines.

[168] 77 FR 72512, 78 FR 46142.

[169] 77 FR 72512.

levels at Arizona Class I areas will be substantially better than predicted in the WRAP modeling that served as the basis for the State's RPGs. In addition, our final BART FIP for the Four Corners Power Plant on the Navajo Nation is expected to result in tens of thousands of tons per year of additional NO_x reductions that will benefit some of Arizona's Class I areas. Likewise, our proposed BART FIP for the Navajo Generating Station, if finalized, will result in substantial visibility benefit for Class I areas.

While we would prefer to quantify these proposed RPGs for each of Arizona's 12 Class I areas based on the new state and federal plans, we lack sufficient time and resources to conduct the type of regional-scale modeling required to develop such numerical RPGs.[170] Nonetheless, we anticipate that the additional controls required in EPA's Regional Haze FIPs will result in an increase in visibility improvement during the 20 percent worst days and the 20 percent best days in all of Arizona's Class 1 Areas.

D. Meeting the Uniform Rate of Progress

As explained in our proposed and final rules on the Arizona RH SIP, the State set RPGs that provide for slower rates of improvement in visibility than the URP for each of the State's twelve Class I areas.[171] Given the variety and location of the sources contributing to visibility impairment in Arizona, EPA considers it unlikely that all of Arizona's Class I areas will meet the URP during this planning period, even with the additional controls required in EPA's Regional Haze FIPs. Therefore, EPA must demonstrate that it is not reasonable to provide for rates of progress consistent with the URP for this planning period, based upon the four RP factors.[172] Given that this demonstration must be based on the same four factors as the initial RP analysis, EPA proposes to find that the extensive reasonable progress analysis underlying our actions on

[170] The regional-scale modeling that formed the basis for Arizona's RPGs was developed by the WRAP's Regional Modeling Center over the course of several years with input from numerous sources.
[171] See 77 FR 75728, 78 FR 29298 and 78 FR 46160.
[172] 40 CFR 51.308(d)(1)(ii).

the Arizona SIP, and the reasonable progress analysis found in this proposal are sufficient to make this demonstration. In particular, for the reasons explained in our proposed and final rules on the Arizona RH SIP, we have approved Arizona's determinations that it is not reasonable to require additional controls to address organic carbon, elemental carbon, coarse mass and fine soil during this planning period.[173] We also approved the State's decision not to require additional controls on non-BART point sources of SO_2.[174] Moreover, based on the analyses set out in the preceding sections of this document, we are now proposing to find that it is not reasonable to require additional controls on most point sources of NO_x or area sources of NO_x and SO_2 during this planning period. However, we are proposing to require additional NO_x controls on two cement kilns. Based on all of these analyses, we propose to find that it is not reasonable for any of Arizona's Class I areas to meet the URP during this planning period.

VII. EPA's Proposed Long-Term Strategy Supplement

In our final rule on the Arizona RH SIP published on July 30, 2013, we disapproved portions of the State's LTS related to three RHR requirements. These requirements were for measures needed to achieve emission reductions for out-of-state Class I areas, emissions limitations and schedules for compliance to achieve the reasonable progress goals, and enforceability of emissions limitations and control measures.[175] These RHR requirements are found in 40 CFR 51.308(d)(3)(ii), (v)(C) and (v)(F). We now are obligated to address these requirements through a FIP under CAA section 110(c). In this section, we describe each of these requirements, our rationale for disapproving these elements in the Arizona RH SIP, and propose how to address these requirements in our FIP.

[173] See 77 FR 75728 for a discussion on sources of organic carbon and elemental carbon (fires), and 78 FR 29297-29299 for a discussion of coarse mass and fine soil.
[174] See 78 FR 46172.
[175] See 78 FR 46173 (codified at 40 CFR 52.145(e)(ii)).

A. Emission Reductions for Out-of-State Class I Areas

Under the RHR, where a state has participated in a regional planning process, the state's LTS must include all measures needed to achieve that state's apportionment of emission reduction obligations agreed upon through that process.[176] Arizona participated in a regional planning process through the WRAP and incorporated the WRAP-developed visibility modeling into the Arizona RH SIP. However, the Arizona RH SIP did not include all measures needed to achieve the State's apportionment of emission reductions that were included in the WRAP modeling. In particular, Arizona's BART determinations lacked the necessary compliance schedules and requirements for operation and maintenance of control equipment and monitoring, recordkeeping and reporting to ensure that the assumed reductions at Arizona's BART sources are achieved. Therefore, we disapproved this element of the Arizona RH SIP.

B. Emissions Limitations and Schedules for Compliance to Achieve RPGs

One of the factors a state must consider in developing its LTS is emissions limitations and schedules for compliance to achieve the State's RPGs for its own Class I areas.[177] As explained in the preceding section, the Arizona RH SIP did not contain any enforceable emission limitations or schedules for compliance to achieve the State's RPGs. Therefore, we found that the Arizona RH SIP did not meet this requirement.

C. Enforceability of Emissions Limitations and Control Measures

Another factor a state must consider in developing its LTS is the enforceability of emissions limitations and control measures.[178] As explained in the preceding sections, Arizona's BART determinations lack provisions to ensure their enforceability. Therefore, we disapproved the Arizona RH SIP with respect to this requirement.

[176] 40 CFR 51.308(d)(3)(ii).
[177] 40 CFR 51.308(d)(3)(v)(C).
[178] 40 CFR 51.308(d)(3)(v)(F).

D. Proposed Partial LTS FIP

The primary flaw in Arizona's LTS is the lack of enforceable emission limitations for BART controls. We propose to remedy this deficiency by promulgating BART emission limitations and compliance schedules as well as monitoring, recordkeeping and reporting requirements, to ensure the enforceability of these limits.

1. Enforceability Requirements for Arizona and EPA's Phase 1 BART Determinations

As part of our final rule published on December 5, 2012, regarding BART for Apache Generating Station, Cholla Power Plant and Coronado Generating Station, we promulgated compliance deadlines and requirements for equipment maintenance and operation including monitoring, recordkeeping and reporting, to ensure the enforceability of both Arizona's and EPA's BART determinations.

2. Enforceability Requirements for EPA's Proposed Phase 3 BART and RP Determinations

As described above, today, we are proposing to promulgate similar requirements for the remaining subject-to-BART sources and pollutants in Arizona. We are also proposing emission limitations and compliance requirements for two RP sources: the Phoenix Cement Clarkdale Plant and the CalPortland Rillito Plant.

3. Enforceability Requirements for Arizona's Phase 2 BART Determinations

The final element of our proposed LTS consists of enforceable emission limitations and associated requirements for PM_{10} at the Hayden and Miami Copper Smelters. While we previously approved the State's determination that existing controls constitute BART for PM_{10} at each of these facilities, the Arizona RH SIP lacked any emission limitation or associated requirements to ensure the enforceability of these determinations, as required under the CAA and EPA's regulations.[179] Therefore, we are proposing to promulgate such limits and associated

[179] See CAA section 110(a)(2)(F) and 40 CFR 51.212(c), 51.308(d)(3)(v)(C) and (F).

compliance requirements for these BART determinations, as necessary to ensure their enforceability.

a. Hayden Smelter PM_{10}

In its BART analysis for PM_{10}, ASARCO relied on the particulate limits established in National Emission Standard for Hazardous Air Pollutants (NESHAP) Subpart QQQ, Primary Copper Smelting at 40 CFR 63.1444(d)(5) and (6).[180] These limits and associated monitoring requirements formed the basis for ASARCO's BART determination, which ADEQ incorporated in its Regional Haze SIP.[181] We are now proposing to incorporate these requirements into the FIP. In particular, we propose to set a limit of 6.2 mg/dscm non-sulfuric acid particulate matter from the primary capture system, and a limit of 23 mg/dscm particulate matter from the secondary capture system, as measured using the test methods specified in 40 CFR 63.1450(b). We propose to require demonstration of compliance with these limits through the applicable procedures in 40 CFR 63.1451 and 1453.

b. Miami Smelter PM_{10}

In the Arizona Regional Haze SIP, ADEQ determined that the NESHAP for Primary Copper Smelting constitutes BART for PM emissions from the Miami Smelter. Because the FMMI smelter is a major source of Hazardous Air Pollutants (HAPs), and therefore subject to the requirements of the NESHAP, these requirements are already incorporated into the facility's Title V permit.[182] We propose to find that these existing, federally enforceable requirements are sufficient to ensure the enforceability of ADEQ's PM_{10} BART determination for the Miami Smelter.

VIII. EPA's Proposal for Interstate Transport

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[180] Letter from Eric Hiser, Counsel for ASARCO, to Balaji Vaidyanathan, ADEQ dated March 20, 2013, page 5.
[181] Arizona RH SIP Supplement (May 3, 2013), Appendix D, page 23, and Section XII.
[182] ADEQ Air Quality Class I Permit Number 53592 issued November 26, 2012, attachment B.

We propose that a combination of SIP and FIP measures will satisfy the FIP obligation for the visibility requirement of CAA section 110(a)(2)(D)(i)(II) for the 1997 8-hour ozone, 1997 $PM_{2.5}$, and 2006 $PM_{2.5}$ NAAQS. As discussed in section II.B (''Overview of Proposed Actions; Interstate Transport of Pollutants that affect Visibility'') of this proposed rule, EPA disapproved Arizona's 2007 and 2009 Transport SIPs as well as its Regional Haze SIP for the interstate transport visibility protection requirement of CAA section 110(a)(2)(D)(i)(II) for the 1997 8-hour ozone, 1997 $PM_{2.5}$, and 2006 $PM_{2.5}$ NAAQS. As noted in our proposed SIP action,[183] we interpret the visibility requirement of section 110(a)(D)(i)(II) as requiring states to include in their SIPs either measures to prohibit emissions that would interfere with attaining RPGs of Class I areas in other states, or a demonstration that emissions from the state's sources and activities will not have the prohibited impacts under the existing SIP. Arizona's 2007 and 2009 Transport SIP revisions indicated that the interstate transport visibility requirement should be assessed in conjunction with the Arizona RH SIP, but did not specify which parts of the RH SIP should be considered as meeting the visibility requirement of section 110(a)(2)(D)(i)(II). Therefore we have considered the Arizona RH SIP as a whole in assessing whether Arizona has met this visibility requirement.

As a result of the partial disapprovals of the Arizona RH SIP, we found that the Arizona SIP did not contain adequate provisions to prohibit emissions that may interfere with SIP measures required of other states to protect visibility. Therefore, we disapproved Arizona's submittals with respect to the interstate transport visibility requirement for the 1997 8-hour ozone, 1997 $PM_{2.5}$, and 2006 $PM_{2.5}$ NAAQS, which triggered the obligation for EPA to promulgate a FIP under CAA section 110(c)(1). We anticipated that this FIP obligation could be

[183] 77 FR 75704 at 75709.

satisfied by a combination of the State's measures that we previously approved and EPA's promulgation of FIPs for the disapproved elements of the Arizona RH SIP.[184]

We propose to find that the combination of elements in the applicable RH SIPs and FIPs will contain adequate provisions to prohibit emissions from Arizona that would interfere with SIP measures required of other states to protect visibility. These elements are the Arizona RH SIP measures that we previously approved;[185] the partial RH FIP that we promulgated on December 5, 2012;[186] and the partial RH FIP we are proposing today. As explained in the LTS section, the combination of all of these measures will ensure that the applicable implementation plan (i.e., the combination of SIP and FIP measures) will include all of the measures needed to achieve Arizona's allotment of emission reductions agreed upon through the WRAP process. We propose that this combination of SIP and FIP measures will satisfy the FIP obligation for the visibility requirement of CAA section 110(a)(2)(D)(i)(II) for the 1997 8-hour ozone, 1997 $PM_{2.5}$, and 2006 $PM_{2.5}$ NAAQS.

IX. Summary of EPA's Proposed Actions

A. Regional Haze

EPA is proposing a FIP to address the remaining portions of the Arizona's RH SIP that we disapproved on July 30, 2013, which includes requirements for Best Available Retrofit Technology, Reasonable Progress, and the Long-term Strategy. We are proposing more stringent emission limits on six sources that impact visibility in 17 Class I areas inside and outside the State. We welcome comments on all of our proposals and indicate specific issues or areas where feedback would be particularly useful. Our proposal includes compliance dates and specific requirements for monitoring, recordkeeping, reporting and equipment operation and maintenance

[184] 77 FR 75704 at 75736.
[185] 77 FR 72512, 78 FR 46142.
[186] 77 FR 72512.

for all of the units covered by this action as described in Part 52 attached to this notice. Today's proposed FIP, once finalized, along with previously approved SIPs and a finalized FIP, will constitute Arizona's regional haze program for the first planning period that ends in 2018.

B. Interstate Visibility Transport

We propose that the interstate transport visibility requirement of section 110(a)(2)(D)(i)(II) for the 1997 8-hour ozone, 1997 $PM_{2.5}$, and 2006 $PM_{2.5}$ NAAQS is satisfied by a combination of SIP and FIP elements. These elements are the Arizona RH SIP measures that we previously approved; the partial RH FIP that we promulgated on December 5, 2012; and the partial RH FIP we are proposing today.

X. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

This proposed action is not a "significant regulatory action" under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011). The proposed FIP applies to only six facilities. It is therefore not a rule of general applicability.

B. Paperwork Reduction Act

This proposed action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. Under the Paperwork Reduction Act, a ''collection of information'' is defined as a requirement for ''answers to * * * identical reporting or recordkeeping requirements imposed on ten or more persons * * *.'' 44 U.S.C. 3502(3)(A). Because the proposed FIP applies to just six facilities, the Paperwork Reduction Act does not apply. See 5 CFR 1320(c). Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid Office of Management and Budget (OMB) control number. The OMB control numbers for our regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions. For purposes of assessing the impacts of today's proposed rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this proposed action on small entities, I certify that this proposed action will not have a significant economic impact on a substantial number of small entities. None of the facilities subject to this proposed rule is owned by a small entity.[187] We continue to be interested in the potential impacts of the proposed rule on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104-4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under section 202 of UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures to State, local, and Tribal governments, in the aggregate, or to the private sector, of $100 million or more (adjusted for inflation) in any 1 year. Before promulgating an EPA rule for which a written statement is needed, section 205 of UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 of UMRA do not apply when they are inconsistent with applicable law. Moreover, section 205 of UMRA allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments, it must have developed under section 203 of UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory

[187] See Regulatory Flexibility Act Screening Analysis for Proposed Arizona Regional Haze Federal Implementation Plan (EPA-R09-OAR-2013-0588).

proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

Under Title II of UMRA, EPA has determined that this proposed rule does not contain a Federal mandate that may result in expenditures that exceed the inflation-adjusted UMRA threshold of $100 million by State, local, or Tribal governments or the private sector in any 1 year. In addition, this proposed rule does not contain a significant Federal intergovernmental mandate as described by section 203 of UMRA nor does it contain any regulatory requirements that might significantly or uniquely affect small governments.[188]

E. Executive Order 13132: Federalism

Executive Order 13132 Federalism (64 FR 43255, August 10, 1999) revokes and replaces Executive Orders 12612 (Federalism) and 12875 (Enhancing the Intergovernmental Partnership). Executive Order 13132 requires EPA to develop an accountable process to ensure "meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications." "Policies that have federalism implications" is defined in the Executive Order to include regulations that have "substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government." Under Executive Order 13132, EPA may not issue a regulation that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, or EPA consults with State and local officials early in the process of developing the proposed regulation. EPA also may not issue a regulation that has federalism implications and that

[188] See "Summary of EPA BART Cost Estimates" in the docket.

preempts State law unless the Agency consults with State and local officials early in the process of developing the proposed regulation.

This rule will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. In this action, EPA is fulfilling our statutory duty under CAA Section 110(c) to promulgate a partial Regional Haze FIP. Thus, Executive Order 13132 does not apply to this action. In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on this proposed rule from State and local officials.

F. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

Subject to the Executive Order 13175 (65 FR 67249, November 9, 2000) EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement.

EPA has concluded that this action, if finalized, will have tribal implications, because it will impose substantial direct compliance costs on tribal governments, and the Federal government will not provide the funds necessary to pay those costs. PCC is a division of Salt River Pima Maricopa Indian Community (SRPMIC or the Community) and profits from the Phoenix Cement Clarkdale Plant are used to provide government services to SRPMIC's members. Therefore, EPA is providing the following tribal summary impact statement as required by section 5(b).

EPA consulted with tribal officials early in the process of developing this regulation to permit them to have meaningful and timely input into its development. In November 2012, we shared our initial analyses with SRPMIC and PCC to ensure that the tribe had an early opportunity to provide feedback on potential controls at the Clarkdale Plant. PCC submitted comments on this initial analysis as part of the rulemaking on the Arizona Regional Haze SIP and we revised our initial analysis based on these comments. On November 6, 2013, the EPA Region 9 Regional Administrator met with the President and other representatives of SRPMIC to discuss the potential impacts of the FIP on SRPMIC. Following this meeting, staff from EPA, SPRMIC and PCC shared further information regarding the Plant and potential impacts of the FIP on SRPMIC.[189]

During these consultations, SRPMIC expressed its concern regarding the potential financial impacts of any new controls that might be required at the Clarkdale Plant. In particular, SRPMIC requested that EPA provide PCC with an extended compliance schedule for any controls in order to enable PCC and SRPMIC to plan for such controls in their long-term budgets and thus mitigate the potential impacts to the Community.[190] However, SRPMIC provided only limited information documenting the potential for such impacts and claimed all such information as CBI.

As explained above, EPA is proposing to determine that it is reasonable to require installation of SNCR at Kiln 4 at the Clarkdale Plant by December 31, 2018. EPA is also seeking comment on the possibility of establishing an annual cap on NO_x emissions from Kiln 4 in lieu of a lb/ton emission limit. An annual cap would allow SRPMIC to delay installation of controls until the Plant's production returns to pre-recession levels and would thus help to address the

[189] See Memorandum to Docket: Summary of Communications and Consultation between EPA, PCC and SRPMIC (January 27, 2014).

Community's concerns about the budgetary impacts of control requirements. EPA specifically solicits additional comment on this proposed rule from tribal officials.

G. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks (62 FR 19885, April 23, 1997), applies to any rule that: (1) is determined to be economically significant as defined under Executive Order 12866; and (2) concerns an environmental health or safety risk that we have reason to believe may have a disproportionate effect on children. EPA interprets EO 13045 as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5-501 of the EO has the potential to influence the regulation. This action is not subject to EO 13045 because it implements specific standards established by Congress in statutes. However, to the extent this proposed rule will limit emissions of NO_x, SO_2 and PM, the rule will have a beneficial effect on children's health by reducing air pollution.

H. Executive Order 13211: Actions Concerning Regulations that Significantly affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12 of the National Technology Transfer and Advancement Act (NTTAA) of 1995 requires Federal agencies to evaluate existing technical standards when developing a new regulation. To comply with NTTAA, EPA must consider and use ‘‘voluntary consensus standards’’ (VCS) if available and applicable when developing programs and policies unless doing so would be inconsistent with applicable law or otherwise impractical. EPA believes that VCS are inapplicable to this action. Today's action does not require the public to perform activities conducive to the use of VCS.

J. Executive Order 12898: Federal Actions to address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994), establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

We have determined that this proposed rule, if finalized, will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. This proposed federal rule limits emissions of NO_x and SO_2 from six facilities in Arizona.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen oxides, Sulfur dioxide, Particulate matter, Reporting and recordkeeping requirements, Visibility, Volatile organic compounds.

AUTHORITY: 42 U.S.C. 7401 et seq.

January 14, 2014	/ signed by /
Date	Jared Blumenfeld Regional Administrator Region 9

Part 52, chapter I, title 40 of the Code of Federal Regulations is proposed to be amended as follows:

PART 52—[AMENDED]

1. The authority citation for Part 52 continues to read as follows:

AUTHORITY: 42 U.S.C. 7401 *et seq.*

D—Arizona

2. Add new paragraphs (i), (j), (k), (l) and (m) to §52.145 Visibility Protection, to read as follows:

(i) *Source-specific federal implementation plan for regional haze at Nelson Lime Plant*

(1) *Applicability*.

This paragraph (i) applies to the owner/operator of the lime kilns designated as Kiln 1 and Kiln 2 at the Nelson Lime Plant located in Yavapai County, Arizona.

(2) Definitions.

Terms not defined below shall have the meaning given them in the Clean Air Act or EPA's regulations implementing the Clean Air Act. For purposes of this paragraph (i):

Ammonia injection shall include any of the following: anhydrous ammonia, aqueous ammonia or urea injection.

Continuous emission monitoring system or CEMS means the equipment required by this section to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of NO_x emissions, SO_2 emissions, , diluent, or stack gas volumetric flow rate.

Kiln 1 means rotary kiln 1, as identified in paragraph (i)(1) of this section.

Kiln 2 means rotary kiln 2, as identified in paragraph (i)(1) of this section.

Kiln operating day means a 24-hour period between 12 midnight and the following midnight during which the kiln operates.

Lime product means the product of the lime kiln calcination process including calcitic lime, dolomitic lime, and dead-burned dolomite.

*NO_x*means nitrogen oxides.

Owner/operator means any person who owns or who operates, controls, or supervises a kiln identified in paragraph (i)(1) of this section.

SO_2 means sulfur dioxide.

Unit means any of the kilns identified in paragraph (i)(1) of this section.

(3) *Emission limitations*.

The owner/operator of each kiln identified in paragraph (i)(1) shall not emit or cause to be emitted pollutants in excess of the following limitations, in pounds of pollutant per ton of lime product (lb/ton), from any kiln. Each emission limit shall be based on a rolling 30 kiln-operating day basis.

Kiln ID	Pollutant Emission Limit	
	NO_x	SO_2
Kiln 1	3.80	9.32
Kiln 2	2.61	9.73

(4) *Compliance Dates*.

(i) The owner /operator of each unit shall comply with the NO_x emissions limitations and other NO_x-related requirements of this paragraph (i) no later than (three years after date of publication of the final rule in the **Federal Register**).

(ii) The owner /operator of each unit shall comply with the SO_2 emissions limitations and other SO_2-related requirements of this paragraph (i) no later than (six months after date of publication of the final rule in the **Federal Register)**.

(5) *Compliance determination*.

(i) Continuous emission monitoring system. At all times after the compliance dates specified in paragraph (i)(4) of this section, the owner/operator of Kiln 1 and 2 shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found at 40 CFR 60.13 and 40 CFR 60, Appendices B and F, to accurately measure the mass emission rate of NO_x and SO_2 , in pounds per hour, from Kiln 1 and 2. The CEMS shall be used by the owner/operator to determine compliance with the emission limitations in paragraph (i)(3) of this section, in combination with data on actual lime production. The owner/operator must operate the monitoring system and collect data at all required intervals at all times that an affected unit is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments).

(ii) Ammonia consumption monitoring. Upon and after the completion of installation of ammonia injection on a unit, the owner or operator shall install, and thereafter maintain and operate, instrumentation to continuously monitor and record levels of ammonia consumption for that unit.

(iii) Compliance determination for NO_x. Compliance with the NO_x emission limit described in paragraph (i)(3) of this section shall be determined based on a rolling 30 kiln-operating day basis. The 30-day rolling NO_x emission rate for each kiln shall be calculated for each kiln operating day in accordance with the following procedure: Step one, sum the hourly pounds of NO_x emitted for the current kiln operating day and the preceding twenty-nine (29) kiln operating days, to calculate the total pounds of NO_x emitted over the most recent thirty (30) kiln operating day period for that kiln; Step two, sum the total lime product, in tons, produced during the current kiln operating day and the preceding twenty-nine (29) kiln operating days, to calculate the total lime product produced over the most recent thirty (30) kiln operating day period for that kiln; Step three, divide the total amount of NO_x calculated from Step one by the total lime product calculated from Step two to calculate the 30-day rolling NO_x emission rate for that kiln. Each 30-day rolling NO_x emission rate shall include all emissions and all lime product that occur during all periods within any kiln operating day, including emissions from startup, shutdown and malfunction.

(iv) Compliance determination for SO_2. Compliance with the SO_2 emission limit described in paragraph (i)(3) of this section shall be determined based on a rolling 30 kiln-operating day basis. The 30-day rolling SO_2 emission rate for each kiln shall be calculated for each kiln operating day in accordance with the following procedure: Step one, sum the hourly pounds of SO_2 emitted for the current kiln operating day and the preceding twenty-nine (29) kiln operating days, to calculate the total pounds of SO_2 emitted over the most recent thirty (30) kiln operating day period for that kiln; Step two, sum the total lime product, in tons, produced during the current kiln operating day and the preceding twenty-nine (29) kiln operating days, to calculate the total lime product produced over the most recent thirty (30) kiln operating day period for that kiln; Step three, divide the total amount of SO_2 calculated from Step one by the total lime product calculated from Step two to calculate the 30-day rolling SO_2 emission rate for that kiln. Each 30-day rolling SO_2 emission rate shall include all emissions and all lime product that occur during all periods within any kiln operating day, including emissions from startup, shutdown and malfunction.

(6) *Recordkeeping*.

The owner/operator shall maintain the following records for at least five years:

(i) All CEMS data, including the date, place, and time of sampling or measurement; parameters sampled or measured; and results.

(ii) All records of lime production.

(iii) Daily 30-day rolling emission rates of NO_x and SO_2, when applicable, calculated in accordance with paragraphs (i)(5)(iii) and (i)(5)(iv) of this section

(iv) Records of quality assurance and quality control activities for emissions measuring systems including, but not limited to, any records required by 40 CFR part 60, appendix F, Procedure 1.

(v) Records of ammonia consumption, as recorded by the instrumentation required in paragraph (i)(5)(ii) of this section.

(vi) Records of all major maintenance activities conducted on emission units, air pollution control equipment, CEMS and clinker production measurement devices.

(vii) Any other records required by 40 CFR part 60, Subpart F, or 40 CFR part 60, Appendix F, Procedure 1.

(7) *Reporting*.

All reports required under this section shall be submitted by the owner/operator to the Director, Enforcement Division (Mail Code ENF-2-1), U.S. Environmental Protection Agency, Region 9, 75 Hawthorne Street, San Francisco, California 94105-3901. All reports required under this section shall be submitted within 30 days after the applicable compliance date(s) in paragraph (i)(4) of this section and at least semiannually thereafter, within 30 days after the end of a semiannual period. The owner/operator may submit reports more frequently than semiannually for the purposes of synchronizing reports required under this section with other reporting requirements, such as the title V monitoring report required by 40 CFR 70.6(a)(3)(iii)(A), but at no point shall the duration of a semiannual period exceed six months.

(i) The owner/operator shall submit a report that lists the daily 30-day rolling emission rates for NO_x and SO_2.

(ii) The owner/operator shall submit excess emissions reports for NO_x and SO_2 limits. Excess emissions means emissions that exceed the emissions limits specified in paragraph (i)(3) of this section. The reports shall include the magnitude, date(s), and duration of each period of excess emissions, specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the unit, the nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted.

(iii) The owner/operator shall submit CEMS performance reports, to include dates and duration of each period during which the CEMS was inoperative (except for zero and span adjustments and calibration checks), reason(s) why the CEMS was inoperative and steps taken to prevent recurrence, and any CEMS repairs or adjustments.

(iv) The owner/operator shall also submit results of any CEMS performance tests required by 40 CFR part 60, appendix F, Procedure 1 (Relative Accuracy Test Audits, Relative Accuracy Audits, and Cylinder Gas Audits).

(v) When no excess emissions have occurred or the CEMS has not been inoperative, repaired, or adjusted during the reporting period, the owner/operator shall state such information in the semiannual report.

(8) *Notifications*.

(i) The owner/operator shall notify EPA of commencement of construction of any equipment which is being constructed to comply with the NO_x emission limits in paragraph (i)(3) of this section.

(ii) The owner/operator shall submit semiannual progress reports on construction of any such equipment.

(iii) The owner/operator shall submit notification of initial startup of any such equipment.

(9) *Equipment Operations*.

(i) At all times, including periods of startup, shutdown, and malfunction, the owner or operator shall, to the extent practicable, maintain and operate the unit including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. Pollution control equipment shall be designed and capable of operating properly to minimize emissions during all expected operating conditions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Regional Administrator which may include, but is not limited to, monitoring results, review of operating and maintenance procedures, and inspection of the kiln.

(ii) After completion of installation of ammonia injection on a unit, the owner or operator shall inject sufficient ammonia to achieve compliance with NO_x emission limits from paragraph (i)(3) for that unit while preventing excessive ammonia emissions.

(10) *Enforcement.*

Notwithstanding any other provision in this implementation plan, any credible evidence or information relevant as to whether the unit would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed, can be used to establish whether or not the owner or operator has violated or is in violation of any standard or applicable emission limit in the plan.

(11) *Affirmative Defense for Malfunctions*.

The following provisions of the Arizona Administrative Code are incorporated by reference and made part of this federal implementation plan:

(i) R-18-2-101, paragraph 65;

(ii) R18-2-310, sections (A), (B), (D) and (E) only; and

(iii) R18-2-310.01.

(j) *Source-specific federal implementation plan for regional haze at H. Wilson Sundt Generating Station*

(1) *Applicability*.

This paragraph (j) applies to the owner and operator of the electricity generating unit (EGU) designated as Unit I4 at the H. Wilson Sundt Generating Station located in Tucson, Pima County, Arizona.

(2) *Definitions*.

Terms not defined below shall have the meaning given them in the Clean Air Act or EPA's regulations implementing the Clean Air Act. For purposes of this paragraph (j):

Ammonia injection shall include any of the following: anhydrous ammonia, aqueous ammonia or urea injection.

Boiler operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the unit.

Continuous emission monitoring system or CEMS means the equipment required by 40 CFR Part 75 and this paragraph (j).

MMBtu means one million british thermal units.

NO_x means nitrogen oxides.

Owner/operator means any person who owns or who operates, controls, or supervises the EGU identified in paragraph (j)(1) of this section.

Pipeline natural gas means a naturally occurring fluid mixture of hydrocarbons as defined in 40 CFR 72.2.

PM means total filterable particulate matter.

PM_{10} means total particulate matter less than 10 microns in diameter.

SO_2 means sulfur dioxide.

Unit means the EGU identified paragraph (j)(1) of this section.

(3) *Emission limitations*.

The owner/operator of the unit shall not emit or cause to be emitted pollutants in excess of the following limitations, in pounds of pollutant per million british thermal units (lb/MMBtu), from the subject unit.

Pollutant	Pollutant Emission Limit
NO_x	0.36
PM	0.030
SO_2	0.23

(4) *Alternative emission limitations*.

The owner/operator of the unit may choose to comply with the following limitations in lieu of the emission limitations listed in paragraph (j)(3).

(i) The owner/operator of the unit shall combust only pipeline natural gas in the subject unit.

(ii) The owner/operator of the unit shall not emit or cause to be emitted pollutants in excess of the following limitations, in pounds of pollutant per million british thermal units (lb/MMBtu), from the subject unit.

Pollutant	Pollutant Emission Limit
NO_x	0.25
PM_{10}	0.010
SO_2	0.00064

(5) *Compliance Dates*.

(i) The owner /operator of the unit subject to this paragraph shall comply with the NO_x and SO_2 emissions limitations of paragraph (j)(3) no later than (three years after date of publication of the final rule in the **Federal Register).**

(ii) The owner /operator of the unit subject to this paragraph shall comply with the PM emissions limitations of paragraph (j)(3) no later than April 16, 2015.

(6) *Alternative Compliance Dates*.

If the owner/operator chooses to comply with the emission limits of paragraph (j)(4) in lieu of paragraph (j)(3), the owner/operator of the unit shall comply with the NO_x, SO_2 and PM_{10} emissions limitations of paragraph (j)(4) no later than December 31, 2017.

(7) *Compliance determination*.

(i) Continuous emission monitoring system.

A. At all times after the compliance date specified in paragraph (j)(5)(i) of this section, the owner/operator of the unit shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found at 40 CFR Part 75, to accurately measure SO_2, NO_x, diluent, and stack gas volumetric flow rate from the unit. All valid CEMS hourly data shall be used to determine compliance with the emission limitations for NO_x and SO_2 in paragraph (j)(3) of this section. When the CEMS is out-of-control as defined by Part 75, that CEMs data shall be treated as missing data and not used to calculate the emission average. Each required CEMS must obtain valid data for at least 90 percent of the unit operating hours, on an annual basis.

B. The owner/operator of the unit shall comply with the quality assurance procedures for CEMS found in 40 CFR Part 75. In addition to these Part 75 requirements, relative accuracy test audits shall be calculated for both the NO_x and SO_2 pounds per hour measurement and the heat input measurement. The CEMs monitoring data shall not be bias adjusted. Calculations of relative accuracy for lb/hr of NO_x, SO_2 and heat input shall be performed each time the Part 75 CEMS undergo relative accuracy testing.

(ii) Ammonia consumption monitoring.

Upon and after the completion of installation of ammonia injection on the unit, the owner or operator shall install, and thereafter maintain and operate, instrumentation to continuously monitor and record levels of ammonia consumption for that unit.

(iii) Compliance determination for NO_x.

Compliance with the NO_x emission limit described in paragraph (j)(3) of this section shall be determined based on a rolling 30 boiler-operating-day basis. The 30-day rolling NO_x emission rate for the unit shall be calculated for each boiler operating day in accordance with the following procedure: Step one, sum the hourly pounds of NO_x emitted for the current boiler operating day and the preceding twenty-nine (29) boiler operating days, to calculate the total pounds of NO_x emitted over the most recent thirty (30) boiler operating day period for that unit; Step two, sum the total heat input, in millions of BTU, during the current boiler operating day and the preceding twenty-nine (29) boiler operating days, to calculate the total heat input over the most recent thirty (30) boiler operating day period for that unit; Step three, divide the total amount of NO_x calculated from Step one by the total heat input calculated from Step two to calculate the 30-day rolling NO_x emission rate, in pounds per million BTU for that unit. Each 30-day rolling NO_x emission rate shall include all emissions and all heat input that occur during all periods within any boiler operating day, including emissions from startup, shutdown and malfunction. If a valid NO_x pounds per hour or heat input is not available for any hour for the unit, that heat input and NO_x pounds per hour shall not be used in the calculation of the 30-day rolling emission rate.

(iv) Compliance determination for SO_2.

Compliance with the SO_2 emission limit described in paragraph (j)(3) of this section shall be determined based on a rolling 30 boiler-operating-day basis. The 30-day rolling SO_2 emission rate for the unit shall be calculated for each boiler operating day in accordance with the following procedure: Step one, sum the hourly pounds of SO2 emitted for the current boiler operating day and the preceding twenty-nine (29) boiler operating days, to calculate the total pounds of SO_2 emitted over the most recent thirty (30) boiler operating day period for that unit; Step two, sum the total heat input, in millions of BTU, during the current boiler operating day and the preceding twenty-nine (29) boiler operating days, to calculate the total heat input over the most recent thirty (30) boiler operating day period for that unit; Step three, divide the total amount of SO_2 calculated from Step one by the total heat input calculated from Step two to calculate the 30-day rolling SO_2 emission rate, in pounds per million BTU for that unit. Each 30-day rolling SO_2 emission rate shall include all emissions and all heat input that occur during all periods within any boiler operating day, including emissions from startup, shutdown and malfunction. If a valid SO_2 pounds per hour or heat input is not available for any hour for the unit, that heat input and SO_2 pounds per hour shall not be used in the calculation of the 30-day rolling emission rate.

(v) Compliance determination for PM.

Compliance with the PM emission limit described in paragraph (j)(3) shall be determined from annual performance stack tests. Within sixty (60) days either preceding or following the compliance deadline specified in paragraph (j)(5)(ii) of this section, and on at least an annual basis thereafter, the owner/operator of the unit shall conduct a stack test on the unit to measure PM using EPA Method 5, in 40 CFR part 60, Appendix A. Each test shall consist of three runs, with each run at least 120 minutes in duration and each run collecting a minimum sample of 60 dry standard cubic feet. Results shall be reported in lb/MMBtu using the calculation in 40 CFR Part 60 Appendix A, Method 19.

(8) *Alternative compliance determination.*

If the owner/operator chooses to comply with the emission limits of paragraph (j)(4), this paragraph may be used in lieu of paragraph (j)(7) to demonstrate compliance with the emission limits in paragraph (j)(4) of this section.

(i) Continuous emission monitoring system.

(A) At all times after the compliance date specified in paragraph (j)(6) of this section, the owner/operator of the unit shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found at 40 CFR Part 75, to accurately measure NO_x, diluent, and stack gas volumetric flow rate from the unit. All valid CEMS hourly data shall be used to determine compliance with the emission limitations for NO_x in paragraph (j)(4) of this section. When the

CEMS is out-of-control as defined by Part 75, that CEMS data shall be treated as missing data and not used to calculate the emission average. Each required CEMS must obtain valid data for at least 90 percent of the unit operating hours, on an annual basis.

(B) The owner/operator of the unit shall comply with the quality assurance procedures for CEMS found in 40 CFR Part 75. In addition to these Part 75 requirements, relative accuracy test audits shall be calculated for both the NO_x pounds per hour measurement and the heat input measurement. The CEMS monitoring data shall not be bias adjusted. Calculations of relative accuracy for lb/hr of NO_x and heat input shall be performed each time the Part 75 CEMS undergo relative accuracy testing.

(ii) Compliance determination for NO_x. Compliance with the NO_x emission limit described in paragraph (j)(4) of this section shall be determined based on a rolling 30 boiler-operating-day basis. The 30-day rolling NO_x emission rate for the unit shall be calculated for each boiler operating day in accordance with the following procedure: Step one, sum the hourly pounds of NO_x emitted for the current boiler operating day and the preceding twenty-nine (29) boiler operating days, to calculate the total pounds of NO_x emitted over the most recent thirty (30) boiler operating day period for that unit; Step two, sum the total heat input, in millions of BTU, during the current boiler operating day and the preceding twenty-nine (29) boiler operating days, to calculate the total heat input over the most recent thirty (30) boiler operating day period for that unit; Step three, divide the total amount of NO_x calculated from Step one by the total heat input calculated from Step two to calculate the 30-day rolling NO_x emission rate, in pounds per million BTU for that unit. Each 30-day rolling NO_x emission rate shall include all emissions and all heat input that occur during all periods within any boiler operating day, including emissions from startup and shutdown. If a valid NO_x pounds per hour or heat input is not available for any hour for the unit, that heat input and NO_x pounds per hour shall not be used in the calculation of the 30-day rolling emission rate.

(iii) Compliance determination for SO_2. Compliance with the SO_2 emission limit for the unit shall be determined from fuel sulfur documentation demonstrating the use of pipeline natural gas.

(iv) Compliance determination for PM_{10}. Compliance with the PM_{10} emission limit for the unit shall be determined from performance stack tests. Within sixty (60) days following the compliance deadline specified in paragraph (j)(6) of this section, and at the request of the Regional Administrator thereafter, the owner/operator of the unit shall conduct a stack test on the unit to measure PM_{10} using EPA Method 201A and Method 202, per 40 CFR part 51, Appendix M. Each test shall consist of three runs, with each run at least 120 minutes in duration and each run collecting a minimum sample of 60 dry standard cubic feet. Results shall be reported in lb/MMBtu using the calculation in 40 CFR Part 60 Appendix A, Method 19.

(9) *Recordkeeping*.

The owner or operator shall maintain the following records for at least five years:

(i) CEMS data measuring NO_x in lb/hr, SO_2 in lb/hr, and heat input rate per hour

(ii) Daily 30-day rolling emission rates of NO_x and SO_2 calculated in accordance with paragraphs (j)(7)(iii) and (j)(7)(iv) of this section

(iii) Records of the relative accuracy test for NO_x lb/hr and SO_2 lb/hr measurement, and hourly heat input measurement.

(iv) Records of quality assurance and quality control activities for emissions systems including, but not limited to, any records required by 40 CFR Part 75.

(v) Records of all major maintenance activities conducted on emission units, air pollution control equipment, and CEMS.

(vi) Any other records required by 40 CFR Part 75.

(vii) Records of ammonia consumption for the unit, as recorded by the instrumentation required in paragraph (j)(7)(ii) of this section.

(viii) All PM stack test results

(10) *Alternative recordkeeping requirements*.

If the owner/operator chooses to comply with the emission limits of paragraph (j)(4), the owner/operator shall maintain the records listed in this paragraph in lieu of the records contained in paragraph (j)(9). The owner or operator shall maintain the following records for at least five years:

(i) CEMS data measuring NO_x in lb/hr and heat input rate per hour

(ii) Daily 30-day rolling emission rates of NO_x calculated in accordance with paragraph (j)(8)(ii) of this section

(iii) Records of the relative accuracy test for NO_x lb/hr measurement and hourly heat input measurement.

(iv) Records of quality assurance and quality control activities for emissions systems including, but not limited to, any records required by 40 CFR Part 75.

(v) Records of all major maintenance activities conducted on emission units, air pollution control equipment, and CEMS.

(vi) Any other records required by 40 CFR Part 75.

(vii) Records sufficient to demonstrate that the fuel for the unit is pipeline natural gas.

(viii) All PM_{10} stack test results.

(11) *Notifications*.

(i) By July 31, 2015, the owner /operator shall notify the Regional Administrator by letter whether it will comply with the emission limits in paragraph (j)(3) of this section or whether it will comply with the emission limits in paragraph (j)(4) of this section

(ii) The owner/operator shall notify EPA of commencement of construction of any equipment which is being constructed to comply with either the NO_x or SO_2 emission limits in paragraph (j)(3) of this section.

(iii) The owner/operator shall submit semiannual progress reports on construction of any such equipment.

(iv) The owner/operator shall submit notification of initial startup of any such equipment.

(12) *Reporting*.

All reports required under this section shall be submitted by the owner/operator to the Director, Enforcement Division (Mail Code ENF-2-1), U.S. Environmental Protection Agency, Region 9, 75 Hawthorne Street, San Francisco, California 94105-3901. All reports required under this section shall be submitted within 30 days after the applicable compliance date(s) in paragraph (j)(5) of this section and at least semiannually thereafter, within 30 days after the end of a semiannual period. The owner/operator may submit reports more frequently than semiannually for the purposes of synchronizing reports required under this section with other reporting requirements, such as the title V monitoring report required by 40 CFR 70.6(a)(3)(iii)(A), but at no point shall the duration of a semiannual period exceed six months.

(i) The owner/operator shall submit a report that lists the daily 30-day rolling emission rates for NO_x and SO_2.

(ii) The owner/operator shall submit excess emission reports for NO_x and SO_2 limits. Excess emissions means emissions that exceed the emissions limits specified in paragraph (j)(3) of this section. Excess emission reports shall include the magnitude, date(s), and duration of each period of excess emissions, specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the unit, the nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted.

(iii) The owner/operator shall submit CEMS performance reports, to include dates and duration of each period during which the CEMS was inoperative (except for zero and span adjustments and calibration checks), reason(s) why the CEMS was inoperative and steps taken to prevent recurrence, and any CEMS repairs or adjustments.

(iv) The owner/operator shall submit the results of any relative accuracy test audits performed during the two preceding calendar quarters.

(v) When no excess emissions have occurred or the CEMS has not been inoperative, repaired, or adjusted during the reporting period, the owner/operator shall state such information in the semiannual report.

(vi) The owner/operator shall submit results of any PM stack tests conducted for demonstrating compliance with the PM limit specified in paragraph (j)(3).

(13) *Alternative reporting requirements*.

If the owner/operator chooses to comply with the emission limits of paragraph (j)(4), the owner/operator shall submit the reports listed in this paragraph in lieu of the reports contained in paragraph (j)(12). All reports required under this paragraph shall be submitted by the owner/operator to the Director, Enforcement Division (Mail Code ENF-2-1), U.S. Environmental Protection Agency, Region 9, 75 Hawthorne Street, San Francisco, California 94105-3901. All reports required under this paragraph shall be submitted within 30 days after the applicable compliance date(s) in paragraph (j)(6) of this section and at least semiannually thereafter, within 30 days after the end of a semiannual period. The owner/operator may submit reports more frequently than semiannually for the purposes of synchronizing reports required under this section with other reporting requirements, such as the title V monitoring report required by 40 CFR 70.6(a)(3)(iii)(A), but at no point shall the duration of a semiannual period exceed six months.

(i) The owner/operator shall submit a report that lists the daily 30-day rolling emission rates for NO_x.

(ii) The owner/operator shall submit excess emissions reports for NO_x limits. Excess emissions means emissions that exceed the emissions limits specified in paragraph (j)(4) of this section. The reports shall include the magnitude, date(s), and duration of each period of excess emissions, specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the unit, the nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted.

(iii) The owner/operator shall submit CEMS performance reports, to include dates and duration of each period during which the CEMS was inoperative (except for zero and span adjustments and calibration checks), reason(s) why the CEMS was inoperative and steps taken to prevent recurrence, and any CEMS repairs or adjustments.

(iv) The owner/operator shall submit the results of any relative accuracy test audits performed during the two preceding calendar quarters.

(v) When no excess emissions have occurred or the CEMS has not been inoperative, repaired, or adjusted during the reporting period, the owner/operator shall state such information in the semiannual report.

(vi) The owner/operator shall submit results of any PM_{10} stack tests conducted for demonstrating compliance with the PM_{10} limit specified in paragraph (j)(4).

(14) *Equipment Operations*.

(i) At all times, including periods of startup, shutdown, and malfunction, the owner or operator shall, to the extent practicable, maintain and operate the unit including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. Pollution control equipment shall be designed and capable of operating properly to minimize emissions during all expected operating conditions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Regional Administrator which may include, but is not limited to, monitoring results, review of operating and maintenance procedures, and inspection of the unit.

(ii) After completion of installation of ammonia injection on a unit, the owner or operator shall inject sufficient ammonia to achieve compliance with NO_x emission limits contained in paragraph (j)(3)forthat unit while preventing excessive ammonia emissions.

(15) *Enforcement.*

Notwithstanding any other provision in this implementation plan, any credible evidence or information relevant as to whether the unit would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed, can be used to establish whether or not the owner or operator has violated or is in violation of any standard or applicable emission limit in the plan.

(16) *Affirmative Defense for Malfunctions*.

The following provisions of the Arizona Administrative Code are incorporated by reference and made part of this federal implementation plan:

(i) R-18-2-101, paragraph 65;

(ii) R18-2-310, sections (A), (B), (D) and (E) only; and

(iii) R18-2-310.01.

(k) *Source-specific federal implementation plan for regional haze at Clarkdale Cement Plant and Rillito Cement Plant*

(1) *Applicability*.

This paragraph (k) applies to each owner/operator of the following cement kilns in the state of Arizona: Kiln 4 located at the cement plant in Clarkdale, Arizona, and Kiln 4 located at the cement plant in Rillito, Arizona.

(2) *Definitions*.

Terms not defined below shall have the meaning given them in the Clean Air Act or EPA's regulations implementing the Clean Air Act. For purposes of this paragraph (k):

Ammonia injection shall include any of the following: anhydrous ammonia, aqueous ammonia or urea injection.

Continuous emission monitoring system or CEMS means the equipment required by this section to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of NO_x emissions, diluent, or stack gas volumetric flow rate.

Kiln operating day means a 24-hour period between 12 midnight and the following midnight during which the kiln operates.

NO_x means nitrogen oxides.

Owner/operator means any person who owns or who operates, controls, or supervises a cement kiln identified in paragraph (k)(1) of this section.

Unit means a cement kiln identified in paragraph (k)(1) of this section

(3) *Emissions Limitations*. The owner/operator of each unit identified in paragraph (k)(1) shall not emit or cause to be emitted NO_x in excess of the following limitations, in pounds per ton of clinker produced, based on a rolling 30-kiln operating day basis.

Cement Kiln	NO_x Emission Limitation
Clarkdale Plant, Kiln 4	2.12
Rillito Plant, Kiln 4	2.67

(4) *Compliance Date*. The owner /operator of each unit identified in paragraph (k)(i) shall comply with the NO_x emissions limitations and other NO_x-related requirements of this paragraph (k) no later than (three years after date of publication of the final rule in the **Federal Register**).

(5) *Compliance Determination*.

(i) Continuous emission monitoring system.

(A) At all times after the compliance date specified in paragraph (k)(4) of this section, the owner/operator of the unit at the Clarkdale Plant shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found at 40 CFR 60.63(f) and (g), to accurately measure concentration by volume of NO_x, diluent, and stack gas volumetric flow rate from the in-line/raw mill stack, as well as the stack gas volumetric flow rate from the coal mill stack. The CEMS shall be used by the owner/operator to determine compliance with the emission limitation in paragraph (k)(3) of this section, in combination with data on actual clinker production. The owner/operator must operate the monitoring system and collect data at all required intervals at all times the affected unit is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments).

(B) At all times after the compliance date specified in paragraph (k)(4) of this section, the owner/operator of the unit at the Rillito Plant shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found at 40 CFR 60.63(f) and (g), to accurately measure concentration by volume of NO_x, diluent, and stack gas volumetric flow rate from the unit. The CEMS shall be used by the owner/operator to determine compliance with the emission limitation in paragraph (k)(3) of this section, in combination with data on actual clinker production. The owner/operator must operate the monitoring system and collect data at all required intervals at all times the affected unit is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments).

(ii) Methods.

(A) The owner/operator of each unit shall record the daily clinker production rates.

(B) The owner/operator of each unit shall calculate and record the 30-kiln operating day average emission rate of NO_x, in lb/ton of clinker produced, as the total of all hourly emissions data for the cement kiln in the preceding 30-kiln operating days, divided by the total tons of clinker produced in that kiln during the same 30-day operating period, using the following equation:

$$E_D = k\frac{1}{(n)}\sum_{i=1}^{n}\frac{C_i Q_i}{P_i}$$

Where:

E_D = 30 kiln operating day average emission rate of NO_x, lb/ton of clinker;

C_i = Concentration of NO_x for hour i, ppm;

Q_i = volumetric flow rate of effluent gas for hour i, where C_i and Q_i are on the same basis (either wet or dry), scf/hr;

P_i = total kiln clinker produced during production hour i, ton/hr;

k = conversion factor, 1.194×10^{-7} for NO_x; and.

n = number of kiln operating hours over 30 kiln operating days, n = 1 to 720.

For each kiln operating hour for which the owner/operator does not have at least one valid 15-minute CEMS data value, the owner/operator must use the average emissions rate (lb/hr) from the most recent previous hour for which valid data are available. Hourly clinker production shall be determined by the owner/operator in accordance with the requirements found at 40 CFR 60.63(b).

(C) At the end of each kiln operating day, the owner/operator shall calculate and record a new 30-day rolling average emission rate in lb/ton clinker from the arithmetic average of all valid hourly emission rates for the current kiln operating day and the previous 29 successive kiln operating days.

(D) Upon and after the completion of installation of ammonia injection on a unit, the owner/operator shall install, and thereafter maintain and operate, instrumentation to continuously monitor and record levels of ammonia consumption that unit.

(6) *Recordkeeping*. The owner/operator of each unit shall maintain the following records for at least five years:

(i) All CEMS data, including the date, place, and time of sampling or measurement; parameters sampled or measured; and results.

(ii) All records of clinker production.

(iii) Daily 30-day rolling emission rates of NO_x, calculated in accordance with paragraph (k)(5)(ii) of this section.

(iv) Records of quality assurance and quality control activities for emissions measuring systems including, but not limited to, any records required by 40 CFR part 60, appendix F, Procedure 1.

(v) Records of ammonia consumption, as recorded by the instrumentation required in paragraph (k)(5)(ii)(D) of this section.

(vi) Records of all major maintenance activities conducted on emission units, air pollution control equipment, CEMS and clinker production measurement devices.

(vii) Any other records required by 40 CFR part 60, Subpart F, or 40 CFR part 60, Appendix F, Procedure 1.

(7) *Reporting*.

All reports required under this section shall be submitted by the owner/operator to the Director, Enforcement Division (Mailcode ENF-2-1), U.S. Environmental Protection Agency, Region 9, 75 Hawthorne Street, San Francisco, California 94105-3901. All reports required under this section shall be submitted within 30 days after the applicable compliance date in paragraph (k)(4) of this section and at least semiannually thereafter, within 30 days after the end of a semiannual period. The owner/operator may submit reports more frequently than semiannually for the purposes of synchronizing reports required under this section with other reporting requirements, such as the title V monitoring report required by 40 CFR 70.6(a)(3)(iii)(A), but at no point shall the duration of a semiannual period exceed six months.

(i) The owner/operator shall submit a report that lists the daily 30-day rolling emission rates for NO_x.

(ii) The owner/operator shall submit excess emissions reports for NO_x limits. Excess emissions means emissions that exceed the emissions limits specified in paragraph (k)(3) of this section. The reports shall include the magnitude, date(s), and duration of each period of excess emissions, specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the unit, the nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted.

(iii) The owner/operator shall submit CEMS performance reports, to include dates and duration of each period during which the CEMS was inoperative (except for zero and span adjustments and calibration checks), reason(s) why the CEMS was inoperative and steps taken to prevent recurrence, and any CEMS repairs or adjustments.

(iv) The owner/operator shall also submit results of any CEMS performance tests required by 40 CFR part 60, appendix F, Procedure 1 (Relative Accuracy Test Audits, Relative Accuracy Audits, and Cylinder Gas Audits).

(v) When no excess emissions have occurred or the CEMS has not been inoperative, repaired, or adjusted during the reporting period, the owner/operator shall state such information in the reports required by paragraph (k)(7)(ii) of this section.

(8) *Notifications*.

(i) The owner/operator shall submit notification of commencement of construction of any equipment which is being constructed to comply with the NO_x emission limits in paragraph (k)(3) of this section.

(ii) The owner/operator shall submit semiannual progress reports on construction of any such equipment.

(iii) The owner/operator shall submit notification of initial startup of any such equipment.

(9) *Equipment operation*.

(i) At all times, including periods of startup, shutdown, and malfunction, the owner or operator shall, to the extent practicable, maintain and operate the unit including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. Pollution control equipment shall be designed and capable of operating properly to minimize emissions during all expected operating conditions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Regional Administrator which may include, but is not limited to, monitoring results, review of operating and maintenance procedures, and inspection of the unit.

(ii) After completion of installation of ammonia injection on a unit, the owner or operator shall inject sufficient ammonia to achieve compliance with NO_x emission limits from paragraph (k)(3)for that unit while preventing excessive ammonia emissions.

(10) *Enforcement*.

Notwithstanding any other provision in this implementation plan, any credible evidence or information relevant as to whether the unit would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed, can be used to establish whether or not the owner or operator has violated or is in violation of any standard or applicable emission limit in the plan.

(11) *Affirmative Defense for Malfunctions*.

The following provisions of the Arizona Administrative Code are incorporated by reference and made part of this federal implementation plan:

(i) R-18-2-101, paragraph 65;

(ii) R18-2-310, sections (A), (B), (D) and (E) only; and

(iii) R18-2-310.01.

(l) *Source-specific federal implementation plan for regional haze at Hayden Copper Smelter*

(1) *Applicability*.

This paragraph (l) applies to each owner/operator of each batch copper converter and anode furnaces #1 and #2 at the copper smelting plant located in Hayden, Gila County, Arizona.

(2) *Definitions*.

Terms not defined below shall have the meaning given them in the Clean Air Act or EPA’s regulations implementing the Clean Air Act. For purposes of this paragraph (l):

Anode furnace means a furnace in which molten blister copper is refined through introduction of a reducing agent such as natural gas.

Batch copper converter means a Pierce-Smith converter or Hoboken converter in which copper matte is oxidized to form blister copper by a process that is performed in discrete batches using a sequence of charging, blowing, skimming, and pouring.

Blister copper means an impure form of copper, typically between 98 and 99 percent pure copper, that is the output of the converters.

Calendar day means a 24 hour period that begins and ends at midnight, local standard time.

Continuous emission monitoring system or CEMS means the equipment required by this section to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of SO_2 emissions, other pollutant emissions, diluent, or stack gas volumetric flow rate.

Copper matte means a material predominately composed of copper and iron sulfides produced by smelting copper ore concentrates.

NO_x means nitrogen oxides.

Owner/operator means any person who owns or who operates, controls, or supervises the equipment identified in paragraph (l)(1) of this section.

SO_2 means sulfur dioxide.

(3) *Emission Capture*.

(i) The owner/operator of the batch copper converters identified in paragraph (j)(1) must operate a capture system that has been designed to maximize collection of process off gases vented from each converter. At all times when one or more converters are blowing, you must operate the capture system consistent with a written operation and maintenance plan that has been prepared according to the requirements in 40 CFR 63.1447(b) and approved by EPA within 180 days of the compliance date in paragraph (j)(5) of this section. The capture system must include a primary capture system as described in 40 CFR 63.1444(d)(2) and a secondary hood as described in 40 CFR 63.1444(d)(2).

(ii)The operation of the batch copper converters and secondary hood shall be optimized to capture the maximum amount of process off gases vented from each converter at all times.

(4) *Emission limitations and work practice standards*.

(i) SO_2 emissions collected by the capture system required by paragraph (l)(3) must be controlled by one or more control devices and reduced by at least 99.81 percent, based on a 30-day rolling average.

(ii) The owner/operator must not cause or allow to be discharged to the atmosphere from any primary capture system required by paragraph (l)(3) off-gas that contains nonsulfuric acid particulate matter in excess of 6.2 mg/dscm as measured using the test methods specified in 40 CFR 63.1450(b)

(iii) The owner/operator must not cause or allow to be discharged to the atmosphere from any secondary capture system required by paragraph (l)(3) off-gas that contains particulate matter in excess of 23 mg/dscm as measured using the test methods specified in 40 CFR 63.1450(a)

(iv) Total NO_x emissions from anode furnaces #1 and #2 and the batch copper converters shall not exceed 40 tons per12-continuous month period.

(v) Anode furnaces #1 and #2 shall only be charged with blister copper or higher purity copper.

(5) *Compliance Dates*.

The owner/operator of each batch copper converter identified in paragraph (l)(1) shall comply with the emissions limitations and other requirements of this section no later than (three years after date of publication of the final rule in the **Federal Register**).

(6) *Compliance determination.*

(i) Continuous emission monitoring system. At all times after the compliance date specified in paragraph (e) of this section, the owner/operator of each batch copper converter identified in paragraph (l)(1) shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found at 40 CFR 60.13 and 40 CFR 60, Appendices B and F, to accurately measure the mass emission rate in pounds per hour of SO_2 emissions 1) entering each control device used to control emissions from the converters, and 2) venting from the converters to the atmosphere after passing through a control device or an uncontrolled bypass stack. The CEMS shall be used by the owner/operator to determine compliance with the emission limitation in paragraph (l)(4) of this plan. The owner/operator must operate the monitoring system and collect data at all required intervals at all times that an affected unit is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments).

(ii) Compliance determination for SO_2. The 30-day rolling SO_2 emission control efficiency for the converters shall be calculated for each calendar day in accordance with the following procedure: Step one, sum the hourly pounds of SO_2 vented to each uncontrolled bypass stack and to each control device used to control emissions from the converters for the current calendar day and the preceding twenty-nine (29) calendar days, to calculate the total pounds of pre-control SO_2 emissions over the most recent thirty (30) calendar day period; Step two, sum the hourly pounds of SO_2 vented to each uncontrolled bypass stack and emitted from the release point of each control device used to control emissions from the converters for the current calendar day and the preceding twenty-nine (29) calendar days, to calculate the total pounds of post-control SO_2 emissions over the most recent thirty (30) calendar day period; Step three, divide the total amount of post-control SO_2 emissions calculated from Step two by the total amount of pre-control SO_2 emissions calculated from Step one, subtract the resulting quotient from one, and multiply the difference by 100 percent to calculate the 30-day rolling SO_2 emission control efficiency as a percentage.

(iii) Compliance determination for nonsulfuric acid particulate matter. Compliance with the emission limit for nonsulfuric acid particulate matter in paragraph (l)(4)(ii) shall be demonstrated by the procedures in 40 CFR 63.1451(b) and 40 CFR 63.1453(a)(2).

(iv) Compliance determination for particulate matter. Compliance with the emission limit for particulate matter in paragraph (l)(4)(iii) shall be demonstrated by the procedures in 40 CFR 63.1451(a) and 40 CFR 63.1453(a)(1).

(v) Compliance determination for NO_x. Compliance with the emission limit for NO_x in paragraph (l)(4)(iv) shall be demonstrated by monitoring natural gas consumption in each of the units identified in paragraph (l)(1) for each calendar day. At the end of each calendar month, the owner/operator shall calculate 12-consecutive month NO_x emissions by multiplying the daily natural gas consumption rates for each unit by an approved emission factor and adding the sums for all units over the previous 12-consecutive month period.

(7) *Alternative compliance determination for sulfuric acid plants*.

If the owner/operator uses one or more double contact acid plants to control SO_2 from the batch copper converters identified in paragraph (l)(1), this paragraph may be used to demonstrate compliance with the emission limit in paragraph (l)(4)(i) of this section.

(i) Continuous emission monitoring system. At all times after the compliance date specified in paragraph (l)(5) of this section, the owner/operator of each batch copper converter identified in paragraph (l)(1) shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found at 40 CFR 60.13 and 40 CFR 60, Appendices B and F, to accurately measure the mass emission rate in pounds per hour of SO_2 emissions venting from the converters to the atmosphere after passing through a control device or an uncontrolled bypass stack. The CEMS shall be used by the owner/operator to determine compliance with the emission limitation in paragraph (l)(4). The owner/operator must operate the monitoring system and collect data at all required intervals at all times that an affected unit is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments).

(ii) Daily sulfuric acid production monitoring. At all times after the compliance date specified in paragraph (l)(5) of this section, the owner/operator of each batch copper converter subject to this section shall monitor and maintain records of sulfuric acid production for each calendar day.

(iii) Compliance determination for SO_2. The 30-day rolling SO_2 emission rate for the converters shall be calculated for each calendar day in accordance with the following procedure: Step one, sum the hourly pounds of SO_2 vented to each uncontrolled bypass stack and emitted from the release point of each double contact acid plant used to control emissions from the converters for the current calendar day and the preceding twenty-nine (29) calendar days, to calculate the total pounds of SO_2 emissions over the most recent thirty (30) calendar day period; Step two, sum the total sulfuric acid production in tons of pure sulfuric acid for the current calendar day and the preceding twenty-nine (29) calendar days, to calculate the total tons of sulfuric acid production over the most recent thirty (30) calendar day period; Step three, divide the total amount of SO_2 emissions calculated from Step one by the total tons of sulfuric acid production calculated from Step one to calculate the 30-day rolling SO_2 emission rate in lbs-SO_2 per ton of sulfuric acid. An emission rate of 4.06 or lower shall be deemed to be in compliance with the emission limit in paragraph (i)(4) of this section.

(8) *Capture system monitoring*.

For each operating limit established under the capture system operation and maintenance plan required by paragraph (l)(4) of this section, the owner/operator must install, operate, and maintain an appropriate monitoring device according to the requirements in paragraphs (a)(1) though (6) of 40 CFR 63.1452 to measure and record the operating limit value or setting at all times the required capture system is operating. Dampers that are manually set and remain in the same position at all times the capture system is operating are exempted from these monitoring requirements.

(9) *Recordkeeping*.

The owner/operator shall maintain the following records for at least five years:

(i) All CEMS data, including the date, place, and time of sampling or measurement; parameters sampled or measured; and results.

(ii) Records of quality assurance and quality control activities for emissions measuring systems including, but not limited to, any records required by 40 CFR part 60, appendix F, Procedure 1.

(iii) Records of all major maintenance activities conducted on emission units, air pollution control equipment, and CEMS.

(iv) Any other records required by 40 CFR part 60, Subpart F, or 40 CFR part 60, Appendix F, Procedure 1.

(v) Records of all monitoring required by paragraph (l)(8) of this section.

(vi) Records of daily sulfuric acid production in tons per day of pure sulfuric acid if the owner/operator chooses to use the alternative compliance determination method in paragraph (l)(7) of this section.

(vii) Records of daily natural gas consumption in each units identified in paragraph (l)(1) and all calculations performed to demonstrate compliance with the limit in paragraph (l)(4)(iv).

(10) *Reporting*.

All reports required under this section shall be submitted by the owner/operator to the Director, Enforcement Division (Mail Code ENF-2-1), U.S. Environmental Protection Agency, Region 9, 75 Hawthorne Street, San Francisco, California 94105-3901. All reports required under this section shall be submitted within 30 days after the applicable compliance date in paragraph (l)(5) of this section and at least semiannually thereafter, within 30 days after the end of a semiannual period. The owner/operator may submit reports more frequently than semiannually for the purposes of synchronizing reports required under this section with other reporting requirements, such as the title V monitoring report required by 40 CFR 70.6(a)(3)(iii)(A), but at no point shall the duration of a semiannual period exceed six months.

(i) The owner/operator shall promptly submit excess emissions reports for the SO_2 limit. Excess emissions means emissions that exceed the emissions limit specified in paragraph (d) of this section. The reports shall include the magnitude, date(s), and duration of each period of excess emissions, specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the unit, the nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted. For the purpose of this paragraph, promptly shall mean within 30 days after the end of the month in which the excess emissions were discovered.

(ii) The owner/operator shall submit CEMS performance reports, to include dates and duration of each period during which the CEMS was inoperative (except for zero and span adjustments and calibration checks), reason(s) why the CEMS was inoperative and steps taken to prevent recurrence, and any CEMS repairs or adjustments. The owner/operator shall submit reports semiannually.

(iii) The owner/operator shall also submit results of any CEMS performance tests required by 40 CFR part 60, appendix F, Procedure 1 (Relative Accuracy Test Audits, Relative Accuracy Audits, and Cylinder Gas Audits).

(iv) When no excess emissions have occurred or the CEMS has not been inoperative, repaired, or adjusted during the reporting period, the owner/operator shall state such information in the semiannual report.

(v) When performance testing is required to determine compliance with an emission limit in paragraph (l)(4) of this section, the owner/operator shall submit test reports as specified in 40 CFR part 63, subpart A

(11) *Notifications*.

(i) The owner/operator shall notify EPA of commencement of construction of any equipment which is being constructed to comply with the capture or emission limits in paragraph (l)(3) or (l)(4) of this section.

(ii) The owner/operator shall submit semiannual progress reports on construction of any such equipment.

(iii) The owner/operator shall submit notification of initial startup of any such equipment.

(12) *Equipment Operations*.

At all times, including periods of startup, shutdown, and malfunction, the owner or operator shall, to the extent practicable, maintain and operate the unit including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. Pollution control equipment shall be designed and capable of operating properly to minimize emissions during all expected operating conditions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Regional Administrator which may include, but is not limited to, monitoring results, review of operating and maintenance procedures, and inspection of the unit.

(13) *Enforcement*.

Notwithstanding any other provision in this implementation plan, any credible evidence or information relevant as to whether the unit would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed, can be used to establish whether or not the owner or operator has violated or is in violation of any standard or applicable emission limit in the plan.

(14) *Affirmative Defense for Malfunctions*.

The following provisions of the Arizona Administrative Code are incorporated by reference and made part of this federal implementation plan:

(i) R-18-2-101, paragraph 65;

(ii) R18-2-310, sections (A), (B), (D) and (E) only; and

(iii) R18-2-310.01.

(m) *Source-specific federal implementation plan for regional haze at Miami Copper Smelter*

(1) *Applicability*.

This paragraph (m) applies to each owner/operator of each batch copper converter and the electric furnace at the copper smelting plant located in Hayden, Gila County, Arizona.

(2) *Definitions*.

Terms not defined below shall have the meaning given them in the Clean Air Act or EPA's regulations implementing the Clean Air Act. For purposes of this paragraph (m):

Batch copper converter means a Pierce-Smith converter or Hoboken converter in which copper matte is oxidized to form blister copper by a process that is performed in discrete batches using a sequence of charging, blowing, skimming, and pouring.

Calendar day means a 24 hour period that begins and ends at midnight, local standard time.

Continuous emission monitoring system or CEMS means the equipment required by this section to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of SO_2 emissions, other pollutant emissions, diluent, or stack gas volumetric flow rate.

Copper matte means a material predominately composed of copper and iron sulfides produced by smelting copper ore concentrates.

Electric furnace means a furnace in which copper matte and slag are heated by electrical resistance without the mechanical introduction of air or oxygen.

NO_x means nitrogen oxides.

Owner/operator means any person who owns or who operates, controls, or supervises the equipment identified in paragraph (m)(1) of this section.

Slag means the waste material consisting primarily of iron sulfides separated from copper matte during the smelting and refining of copper ore concentrates.

SO_2 means sulfur dioxide.

(3) *Emission Capture*.

(i)The owner/operator of the batch copper converters identified in paragraph (k)(1) must operate a capture system that has been designed to maximize collection of process off gases vented from each converter. At all times when one or more converters are blowing, you must operate the capture system consistent with a written operation and maintenance plan that has been prepared according to the requirements in 40 CFR 63.1447(b) and approved by EPA within 180 days of the compliance date in paragraph (j)(5) of this section . The capture system must include a primary capture system as described in 40 CFR 63.1444(d)(3) and a secondary hood as described in 40 CFR 63.1444(d)(2).

(ii)The operation of the batch copper converters and secondary hood shall be optimized to capture the maximum amount of process off gases vented from each converter at all times.

(4) *Emission limitations and work practice standards*.

(i) SO_2 emissions collected by the capture system required by paragraph (m)(3) must be controlled by one or more control devices and reduced by at least 99.69 percent, based on a 30-day rolling average.

(ii) Total NO_x emissions the electric furnace and the batch copper converters shall not exceed 40 tons per12-continuous month period.

(iii) The owner/operator shall not actively aerate the electric furnace.

(5) *Compliance Dates*.

The owner/operator of each batch copper converter identified in paragraph (m)(1) shall comply with the emissions limitations and other requirements of this section no later than (three years after date of publication of the final rule in the **Federal Register**).

(6) *Compliance determination*.

(i) Continuous emission monitoring system. At all times after the compliance date specified in paragraph (e) of this section, the owner/operator of each batch copper converter identified in paragraph (m)(1) shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found at 40 CFR 60.13 and 40 CFR 60, Appendices B and F, to accurately measure the mass emission rate in pounds per hour of SO_2 emissions 1) entering each control device used to control emissions from the converters, and 2) venting from the converters to the atmosphere after passing through a control device or an uncontrolled bypass stack. The CEMS shall be used by the owner/operator to determine compliance with the emission limitation in paragraph (m)(4) of this plan. The owner/operator must operate the monitoring system and collect data at all required intervals at all times that an affected unit is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments).

(ii) Compliance determination for SO_2. The 30-day rolling SO_2 emission control efficiency for the converters shall be calculated for each calendar day in accordance with the following procedure: Step one, sum the hourly pounds of SO_2 vented to each uncontrolled bypass stack and to each control device used to control emissions from the converters for the current calendar day and the preceding twenty-nine (29) calendar days, to calculate the total pounds of pre-control SO_2 emissions over the most recent thirty (30) calendar day period; Step two, sum the hourly pounds of SO_2 vented to each uncontrolled bypass stack and emitted from the release point of each control device used to control emissions from the converters for the current calendar day and the preceding twenty-nine (29) calendar days, to calculate the total pounds of post-control SO_2 emissions over the most recent thirty (30) calendar day period; Step three, divide the total amount of post-control SO_2 emissions calculated from Step two by the total amount of pre-control SO_2 emissions calculated from Step one, subtract the resulting quotient from one, and multiply the difference by 100 percent to calculate the 30-day rolling SO_2 emission control efficiency as a percentage.

(iii) Compliance determination for NO_x. Compliance with the emission limit for NO_x in paragraph (m)(4)(ii) shall be demonstrated by monitoring natural gas consumption in each of the units identified in paragraph (m)(1) for each calendar day. At the end of each calendar month, the owner/operator shall calculate monthly and 12-consecutive month NO_x emissions by multiplying the daily natural gas consumption rates for each unit by an approved emission factor and adding the sums for all units over the previous 12-consecutive month period.

(7) *Alternative compliance determination for sulfuric acid plants*.

If the owner/operator uses one or more double contact acid plants to control SO_2 from the batch copper converters identified in paragraph (m)(1), this paragraph may be used to demonstrate compliance with the emission limit in paragraph (m)(4)(i) of this section.

(i) Continuous emission monitoring system. At all times after the compliance date specified in paragraph (m)(5) of this section, the owner/operator of each batch copper converter identified in paragraph (m)(1) shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found at 40 CFR 60.13 and 40 CFR 60, Appendices B and F, to accurately measure the mass emission rate in pounds per hour of SO_2 emissions venting from the converters to the atmosphere after passing through a control device or an uncontrolled bypass stack. The CEMS shall be used by the owner/operator to determine compliance with the emission limitation in paragraph (m)(4). The owner/operator must operate the monitoring system and collect data at all required intervals at all times that an affected unit is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments).

(ii) Daily sulfuric acid production monitoring. At all times after the compliance date specified in paragraph (m)(5) of this section, the owner/operator of each batch copper converter subject to this section shall monitor and maintain records of sulfuric acid production for each calendar day.

(iii) Compliance determination for SO_2. The 30-day rolling SO_2 emission rate for the converters shall be calculated for each calendar day in accordance with the following procedure: Step one, sum the hourly pounds of SO_2 vented to each uncontrolled bypass stack and emitted from the release point of each double contact acid plant used to control emissions from the converters for the current calendar day and the preceding twenty-nine (29) calendar days, to calculate the total pounds of SO_2 emissions over the most recent thirty (30) calendar day period; Step two, sum the total sulfuric acid production in tons of pure sulfuric acid for the current calendar day and the preceding twenty-nine (29) calendar days, to calculate the total tons of sulfuric acid production over the most recent thirty (30) calendar day period; Step three, divide the total amount of SO_2 emissions calculated from Step one by the total tons of sulfuric acid production calculated from Step one to calculate the 30-day rolling SO_2 emission rate in lbs-SO_2 per ton of sulfuric acid. An emission rate of 4.06 or lower shall be deemed to be in compliance with the emission limit in paragraph (i)(4) of this section.

(8) *Capture system monitoring*.

For each operating limit established under the capture system operation and maintenance plan required by paragraph (m)(4) of this section, the owner/operator must install, operate, and maintain an appropriate monitoring device according to the requirements in paragraphs (a)(1) though (6) of 40 CFR 63.1452 to measure and record the operating limit value or setting at all times the required capture system is operating. Dampers that are manually set and remain in the same position at all times the capture system is operating are exempted from these monitoring requirements.

(9) *Recordkeeping*.

The owner/operator shall maintain the following records for at least five years:

(i) All CEMS data, including the date, place, and time of sampling or measurement; parameters sampled or measured; and results.

(ii) Records of quality assurance and quality control activities for emissions measuring systems including, but not limited to, any records required by 40 CFR part 60, appendix F, Procedure 1.

(iii) Records of all major maintenance activities conducted on emission units, air pollution control equipment, and CEMS.

(iv) Any other records required by 40 CFR part 60, Subpart F, or 40 CFR part 60, Appendix F, Procedure 1.

(v) Records of all monitoring required by paragraph (m)(8) of this section.

(vi) Records of daily sulfuric acid production in tons per day of pure sulfuric acid if the owner/operator chooses to use the alternative compliance determination method in paragraph (m)(7) of this section.

(vii) Records of daily natural gas consumption in each units identified in paragraph (m)(1) and all calculations performed to demonstrate compliance with the limit in paragraph (m)(4)(iv).

(10) *Reporting*.

All reports required under this section shall be submitted by the owner/operator to the Director, Enforcement Division (Mail Code ENF-2-1), U.S. Environmental Protection Agency, Region 9, 75 Hawthorne Street, San Francisco, California 94105-3901. All reports required under this section shall be submitted within 30 days after the applicable compliance date in paragraph (m)(5) of this section and at least semiannually thereafter, within 30 days after the end of a semiannual period. The owner/operator may submit reports more frequently than semiannually for the purposes of synchronizing reports required under this section with other reporting requirements, such as the title V monitoring report required by 40 CFR 70.6(a)(3)(iii)(A), but at no point shall the duration of a semiannual period exceed six months.

(i) The owner/operator shall promptly submit excess emissions reports for the SO_2 limit. Excess emissions means emissions that exceed the emissions limit specified in paragraph (d) of this section. The reports shall include the magnitude, date(s), and duration of each period of excess emissions, specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the unit, the nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted. For the purpose of this paragraph, promptly shall mean within 30 days after the end of the month in which the excess emissions were discovered.

(ii) The owner/operator shall submit CEMS performance reports, to include dates and duration of each period during which the CEMS was inoperative (except for zero and span adjustments and calibration checks), reason(s) why the CEMS was inoperative and steps taken to prevent recurrence, and any CEMS repairs or adjustments. The owner/operator shall submit reports semiannually.

(iii) The owner/operator shall also submit results of any CEMS performance tests required by 40 CFR part 60, appendix F, Procedure 1 (Relative Accuracy Test Audits, Relative Accuracy Audits, and Cylinder Gas Audits).

(iv) When no excess emissions have occurred or the CEMS has not been inoperative, repaired, or adjusted during the reporting period, the owner/operator shall state such information in the semiannual report.

(v) When performance testing is required to determine compliance with an emission limit in paragraph (m)(4) of this section, the owner/operator shall submit test reports as specified in 40 CFR part 63, subpart A

(11) *Notifications*.

(i) The owner/operator shall notify EPA of commencement of construction of any equipment which is being constructed to comply with the capture or emission limits in paragraph (m)(3) or (m)(4) of this section.

(ii) The owner/operator shall submit semiannual progress reports on construction of any such equipment.

(iii) The owner/operator shall submit notification of initial startup of any such equipment.

(12) *Equipment Operations*.

At all times, including periods of startup, shutdown, and malfunction, the owner or operator shall, to the extent practicable, maintain and operate the unit including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. Pollution control equipment shall be designed and capable of operating properly to minimize emissions during all expected operating conditions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Regional Administrator which may include, but is not limited to, monitoring results, review of operating and maintenance procedures, and inspection of the unit.

(13) *Enforcement*.

Notwithstanding any other provision in this implementation plan, any credible evidence or information relevant as to whether the unit would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed, can be used to establish whether or not the owner or operator has violated or is in violation of any standard or applicable emission limit in the plan.

(14) *Affirmative Defense for Malfunctions*.

The following provisions of the Arizona Administrative Code are incorporated by reference and made part of this federal implementation plan:

(i) R-18-2-101, paragraph 65;

(ii) R18-2-310, sections (A), (B), (D) and (E) only; and

(iii) R18-2-310.01.