Appendix D

Arizona BART – Supplemental Information

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Arizona Best Available Retrofit Technology (BART) Analysis and Determination

Arizona Department of Environmental Quality

Technical Support Document

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I. EXECUTIVE SUMMARY

Sections 169A and 169B of the Clean Air Act were promulgated by Congress in the 1990 Clean Air Act Amendments with the intent of preventing any future, and remedying any existing, impairment of visibility caused by manmade sources in 156 mandatory Class I areas. Through this requirement, Congress set the goal of achieving natural visibility conditions in the Class I areas by 2064. In the interim, States are required to make reasonable progress towards the achievement of this national goal.

Title 40 CFR §§ 51.300 through 309 (the "regional haze rules") implement §§ 169A and 169B of the Clean Air Act and require States to submit state implementation plans (SIPs) to address regional haze visibility impairment in the 156 Class I areas. These SIPs are intended to be the first in a series of actions that will become long term regional haze strategies to demonstrate reasonable further progress toward the goal that Congress set. One of the tools provided to the States to address reasonable further progress is called Best Available Retrofit Technology, or BART.

The regional haze rules use the term "BART-eligible source" to describe the sources that are potentially subject to this program. BART-eligible sources are those sources that have the potential to emit 250 tons or more of a visibility-impairing air pollutant; were constructed between August 7, 1962 and August 7, 1977, and whose operations fall within one or more of the 26 specifically listed source categories. Once a facility has been determined to be BART-eligible, air dispersion modeling tools are used to determine if that facility causes or contributes to regional haze. If a State determines that the facility "emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area," then the facility is deemed to be subject-to-BART. Visibility impairing pollutants include emissions of oxides of nitrogen (NOx), sulfur dioxide (SO2) and particulate matter (PM). The term "particulate matter" includes particles with an aerodynamic diameter that is less than 10 microns (μm), and particles with an aerodynamic diameter that is less than 2.5 μm.

On June 9, 2006, ADEQ provided potential emissions information along with stack parameters for each potentially-BART-eligible facility to the Western Regional Air Partnership's (WRAP's) Regional Modeling Center, which performed a CALPUFF modeling analysis to determine the predicted visibility impairment apportioned to each facility.

On June 7, 2007, the WRAP's Regional Modeling Center provided ADEQ with the results of the CALPUFF modeling analysis. Based upon the CALPUFF modeling results, ADEQ determined that if a "potentially-BART-eligible" source's twenty-second highest (98th percentile) visibility impact across the three years of modeling was greater than 0.5 deciviews (dv) in any Class I area less than 300 kilometers away, the facility would be considered to contribute to impairment of visibility in that Class I area. Similarly, if the "potentially-BART-eligible" source's impact was found to be greater than 1.0 dv in any Class I area less than 300 kilometers away, the facility would be considered to cause impairment of visibility in that Class I area. In most cases where a "potentially-BART-eligible" source was found to have emissions that contributed to, or caused, impairment of visibility in a Class I area, ADEQ determined that the facility was "potentially-subject-to-BART." In some cases where a facility's contributions to impairment of visibility in a Class I area were within 20% of 0.5 dv, ADEQ requested that the source provide further information demonstrating that the facility was not "potentially-subject-to-BART." As a result, nine BART-eligible facilities were determined to be potentially-subject-to-BART, and one facility was recommended for further evaluation.

On July 13, 2007, eight sources that were potentially-subject-to-BART and another source that was recommended for further evaluation were provided with a set of three options: (i) demonstrate that the

facility is not BART-eligible; (ii) demonstrate that while the facility is BART-eligible, it is not potentially-subject-to-BART as the facility does not cause or contribute to regional haze; or (iii) agree that the facility is potentially-subject-to-BART and conduct a BART analysis for the facility. The one potentially-subject-to-BART facility that did not receive a letter from ADEQ (Tucson Electric Power Company's Irvington Generating Station) was also subject to additional scrutiny. Due to on-going conversations and information that Tucson Electric Power (TEP) had already submitted, ADEQ did not provide that facility a letter on July 13, 2007. The ten facilities and the options that were chosen are as follows:

Option 1: Demonstrate that the facility is not BART-eligible:
TEP - Irvington Generating Station

Option 2: Demonstrate that while the facility is BART-eligible, it is not subject-to-BART:
Arizona Portland Cement Company
APS West Phoenix
ASARCO Hayden Smelter
Chemical Lime Nelson Lime Plant
Freeport-McMoRan Miami Smelter (formerly Phelps Dodge Miami Smelter)

Option 3: Conduct a BART analysis:
Catalyst Paper (Snowflake) Inc. (formerly Abitibi Consolidated)
Arizona Electric Power Cooperative (AEPCO)
APS Cholla Power Plant
SRP Coronado Generating Station

ADEQ analysis of the information that was submitted by each of the companies listed above resulted in the following determinations:

Arizona Sources That Chose to Demonstrate "Not BART-Eligible":
TEP - Irvington Generating Station

Arizona Sources That Chose to Demonstrate Not "Potentially-Subject-to-BART":
Arizona Portland Cement Company
APS West Phoenix
Chemical Lime Nelson Lime Plant

Facilities That Required a BART Analysis:
Catalyst Paper
AEPCO
APS Cholla Power Plant
ASARCO Hayden Smelter
Freeport-McMoRan Miami Smelter
SRP Coronado Generating Station

With the exceptions of the ASARCO Hayden Smelter and the Freeport-McMoRan Miami Smelter, those facilities which were determined to be subject-to-BART agreed with ADEQ's June 13, 2007, letter, and submitted their own analyses of what BART should be for each facility. The Freeport-McMoRan Miami Smelter also provided information about BART applicability to its facility. While the company agreed that BART was applicable to specific emissions units, it provided arguments that the existing controls and emissions limitations at the facility comprised BART. ADEQ reviewed these arguments and, with some supplementary information, was able to conclude that the same arguments applied to the ASARCO

Hayden Smelter. After reviewing the analyses submitted, ADEQ determined that the following controls and emissions limitations constituted BART:

Table 1.1 – NO_X BART		
Facility	**BART Control**	**BART Limit**
Catalyst Paper	**Power Boiler #2:** No additional controls	**Power Boiler #2:** 0.70 lb/MMBtu
AEPCO	**ST1:** LNB with Flu Gas Recirculation (FGR) **ST2:** LNB with OFA **ST3:** LNB with OFA	**ST1:** 0.056 lb/MMBtu **ST2:** 0.31 lb/MMBtu **ST3:** 0.31 lb/MMBtu
APS Cholla Power Plant	**Unit 2:** LNB with Separate Over Fire Air (SOFA) **Unit 3:** LNB with SOFA **Unit 4:** LNB with SOFA	**Unit 2:** 0.22 lb/MMBtu **Unit 3:** 0.22 lb/MMBtu **Unit 4:** 0.22 lb/MMBtu
ASARCO Hayden Smelter	Not Applicable	Not Applicable
Freeport-McMoRan Miami Smelter	Not Applicable	Not Applicable
SRP Coronado Generating Station	**Unit 1:** LNB with OFA **Unit 2:** LNB with OFA	**Unit 1:** 0.32 lb/MMBtu **Unit 2:** 0.32 lb/MMBtu

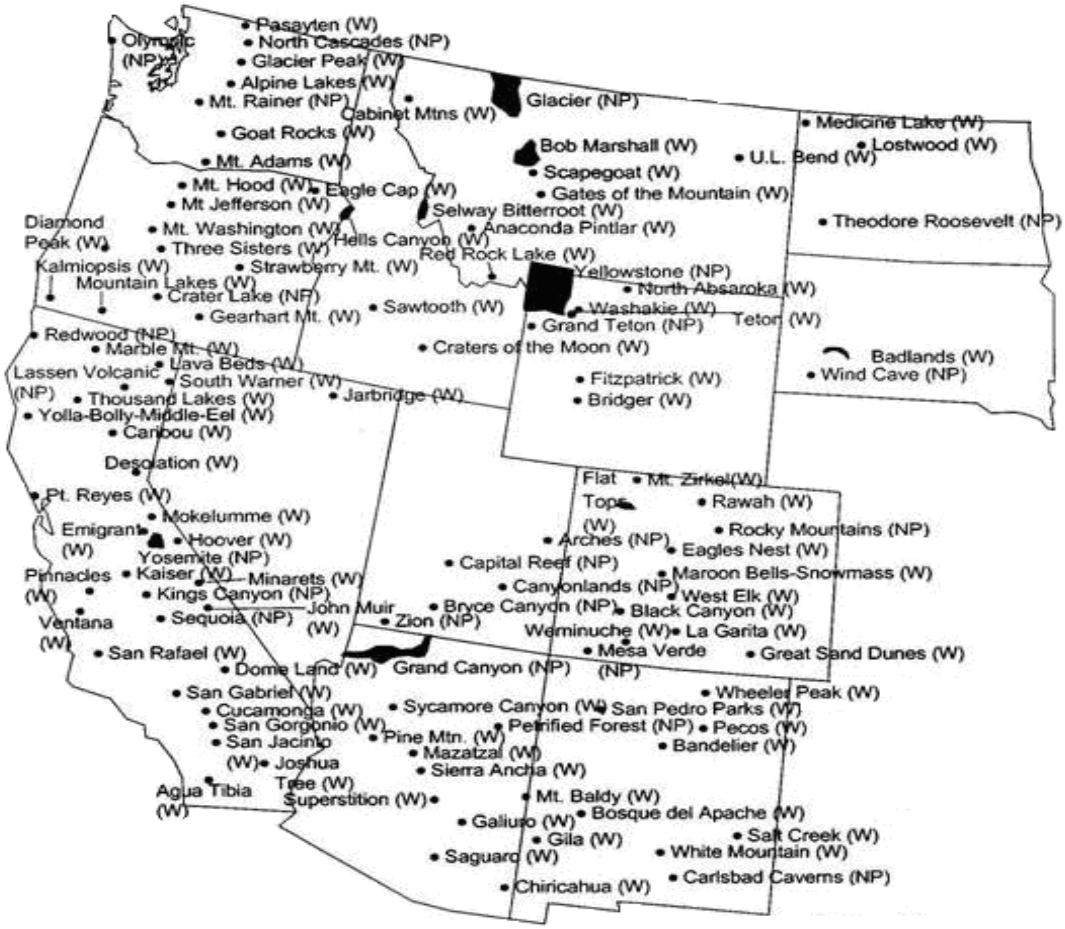
Table 1.2 – PM_{10} BART		
Facility	**BART Control**	**BART Limit**
Catalyst Paper	Not applicable	Not Applicable
AEPCO	**ST1:** Combustion of Pipeline Natural Gas (PNG) **ST2:** Electro Static Precipitator (ESP) Upgrades **ST3:** ESP Upgrades	**ST1:** 0.0075 lb/MMBtu for PNG **ST2:** 0.03 lb/MMBtu **ST3:** 0.03 lb/MMBtu
APS Cholla Power Plant	**Unit 2:** Fabric Filter **Unit 3:** Existing Fabric Filter **Unit 4:** Existing Fabric Filter	**Unit 2:** 0.015 lb/MMBtu **Unit 3:** 0.015 lb/MMBtu **Unit 4:** 0.015 lb/MMBtu
ASARCO Hayden Smelter	Not Applicable	Not Applicable
Freeport-McMoRan Miami Smelter	Existing Controls - Primary Copper Smelting NESHAP	Primary Copper Smelting NESHAP
SRP Coronado Generating Station	Existing Hot Side ESPs	0.03 lb/MMBtu

Table 1.3 – SOx BART		
Facility	**BART Control**	**BART Limit**
Catalyst Paper	**Power Boiler #2:** Upgraded scrubber/Baseline	**Power Boiler #2:** 0.80 lb/MMBtu
AEPCO	**ST1:** Use only PNG **ST2:** Existing Wet Limestone Scrubber **ST3:** Existing Wet Limestone Scrubber	**ST1:** 0.00064 lb/MMBtu for PNG **ST2:** 0.15 lb/MMBtu **ST3:** 0.15 lb/MMBtu
APS Cholla Power Plant	**Unit 2:** Wet Lime Scrubber **Unit 3:** Wet Lime Scrubber **Unit 4:** Wet Lime Scrubber	**Unit 2:** 0.15 lb/MMBtu **Unit 3:** 0.15 lb/MMBtu **Unit 4:** 0.15 lb/MMBtu
ASARCO Hayden Smelter	Existing Controls - Double Contact Acid Plant	Existing Controls
Freeport-McMoRan Miami Smelter	Existing Controls – Double Contact Acid Plant	Existing Controls
SRP Coronado Generating Station	**Unit 1:** Wet FGD **Unit 2:** Wet FGD	**Unit 1:** 0.08 lb/MMBtu **Unit 2:** 0.08 lb/MMBtu

II. Regional Haze Background

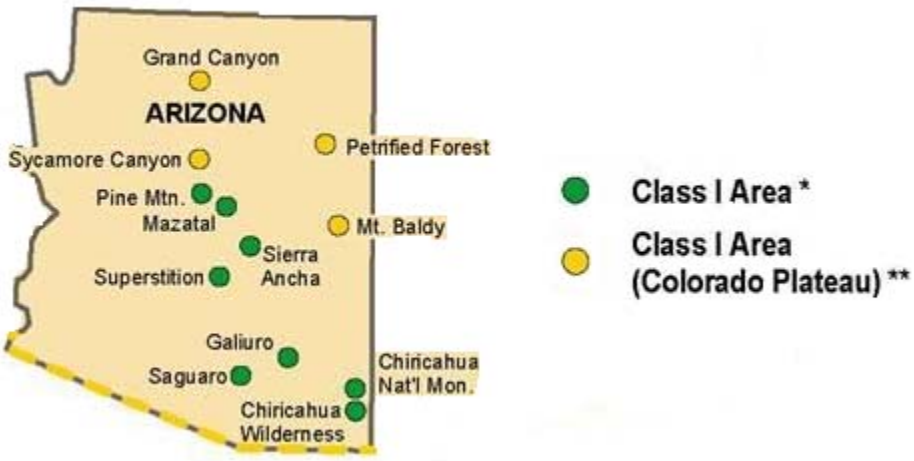
As noted in Section I, there are 156 mandatory, Federally-protected parks and wildernesses throughout the United States that make up Class I areas throughout the country. Of these Class I areas, more than 70 percent (110) are in the Western Continental United States (see Figure 2.1).

Figure 2.1: Class I Areas in the Western Continental United States



Arizona is home to 12 Class I Areas, including the Grand Canyon and Petrified Forest National Parks; the Mount Baldy, Sycamore Canyon, Pine Mountain, Mazatzal, Sierra Ancha, Superstition, Galiuro, Saguaro, and Chiricahua Wilderness Areas; and the Chiricahua National Monument (see Figure 2.2).

Figure 2.2: Arizona Class I Areas



In 1999, EPA adopted regional haze rules that address Congress' stated intent to remedy the existing visibility impairment, and to prevent future visibility impairment in the mandatory Class I areas. Congress also stated its goal that visibility in the Class I areas return to natural conditions by the year 2064. To achieve this, EPA's rules required the States to submit SIPs to address visibility impairment. Arizona's SIP must provide reasonable progress towards the national goal for the 12 Class I areas within the state, as well as address progress in those Class I areas outside Arizona that are impacted by emissions of visibility impairing pollutants originating within the State.

Title 40 CFR 51 §§ 308 and 309 both require States to address visibility impairing pollutant emissions from stationary sources. The principal tool for addressing such emissions is the requirement for specific stationary sources to install BART

III. BACKGROUND FOR BART

Clean Air Act Sections 169A(b)(2) and (g)(7) use the term "major stationary source" to describe those sources that are the focus of the BART requirement. Because this term introduces some potential confusion with other Clean Air Act requirements which also use the term "major stationary source", EPA's regional haze rules coined the term "BART-eligible source" to describe the sources that might be subject to this program. BART-eligible sources are those sources which have the potential to emit 250 tons or more of a visibility-impairing air pollutant, were put into place between August 7, 1962, and August 7, 1977, and whose operations fall within one or more of the 26 specifically listed source categories.

Once a facility has been determined to be BART-eligible, an air dispersion modeling tool is used to determine if that facility causes or contributes to regional haze. If a State determines that the facility "emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area," then the facility is deemed to be subject-to-BART. Visibility impairing pollutants include emissions of oxides of nitrogen (NOx), sulfur dioxide (SO2) and particulate matter (PM). The term particulate matter includes particles with an aerodynamic diameter that is less than 10 microns (μm), and particles with an aerodynamic diameter that is less than 2.5 μm.

The regional haze rules at 40 CFR 51.308(e)(1)(ii) require States to address any BART-eligible existing source that is determined by the State to emit any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I area. In addressing BART, the Clean Air Act requires the State to consider the following factors:

- The costs of compliance;
- The energy and non-air quality environmental impacts of compliance;
- Any existing pollution control technology already in use at the source;
- The remaining useful life of the source; and
- The degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

Over the course of the regional haze rules, there have been a number of challenges to the provisions of the rules and the methodologies prescribed or accepted by EPA. In 1999, EPA explained in its preamble to the rules that the BART requirements demonstrated Congress' intent to focus attention directly on the problem of pollution from a specific set of sources which, as determined by a State, emit any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I area.

Specifically, EPA concluded that if a potentially-subject-to-BART source was located within an area upwind from a downwind Class I area, that source "may reasonably be anticipated to cause or contribute" to visibility impairment in the Class I area. The regional haze rules address visibility impairment resulting from emissions from a multitude of sources that are located across a wide geographic area. The problem of regional haze is caused in large part by the long-range transport of emissions from multiple sources. Therefore, EPA had also concluded that when weighing the factors set forth in the statute for determining BART, the States should consider the collective impact of BART sources on visibility. In particular, when considering the degree of visibility improvement that could reasonably be anticipated to result from the use air pollution control technology, EPA explained that the State should consider the degree of improvement in visibility that would result from the cumulative impact of applying controls to all sources subject-to-BART. EPA then proposed that the States should use this analysis to determine the appropriate BART emission limitations for specific sources.

In American Corn Growers v. EPA, in addition to other challenges to the rules, industry petitioners challenged EPA's interpretations that any source with any potential impacts in any Class I area should be subject-to-BART, and that BART should be applied after considering the collective impacts of BART sources on Class I areas. In 2002, the court concluded that the BART provisions in the 1999 regional haze rule were inconsistent with the provision in the Clean Air Act, as the Act gave the "states broad authority over BART determinations." 291 F.3d at 8.

With respect to the test for determining whether a source is subject-to-BART, the court held that the method that EPA had prescribed for determining which eligible sources are subject-to-BART illegally constrained the authority Congress had conferred to the States. Although the court did not decide whether EPA's proposed general collective contribution approach to determining BART was inconsistent with the Clean Air Act, the court did state that "[i]f the [regional haze rule] contained some kind of a mechanism by which a state could exempt a BART-eligible source on the basis of an individual contribution determination, then perhaps the plain meaning of the Act would not be violated. But the [regional haze rule] contains no such mechanism." Id, at 12.

With respect to EPA's interpretation that the Clean Air Act required the States to consider the degree of improvement in visibility that would result from the cumulative impact of applying controls in determining BART, the court also found that EPA was inconsistent with the language of the Act. 291 F.3d at 8. Based on its review of the statute, the court concluded that the five statutory factors in section 169A(g)(2) "were meant to be considered together by the states." Id. At 8.

On July 6, 2005, EPA took action to address the court's vacatur of the requirement in the regional haze rule requiring States to assess visibility impacts on a cumulative basis in determining which sources are subject-to-BART. Because this requirement was found only in the preamble to the 1999 regional haze rule, EPA concluded that no changes to the regulations were required. Instead, this issue was ultimately addressed by the BART guidelines, which provided States with different techniques and methods for determining which BART-eligible sources "may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area."

The July 6, 2005, amendments to the rules also required the States to consider the degree of visibility improvement resulting from a source's installation and operation of retrofit technology, along with the other statutory factors set out in Clean Air Act § 169A(g)(2), when making a BART determination. This was accomplished by listing the visibility improvement factor with the other statutory BART determination factors in 40 CFR 51.308(e)(91)(A), so that States are now required to consider all five factors, including visibility impacts, on an individual source basis when making each source's BART determination.

IV. ARIZONA "POTENTIALLY-SUBJECT-TO-BART" DETERMINATION PROCESS

A. Identification of Potentially-BART-Eligible Emissions Units

On April 4, 2005, the Stationary Sources Joint Forum (SSJF) of the WRAP published a draft report identifying BART-eligible sources in the WRAP region[1]. This report took a broad-brush approach to reviewing existing stationary sources of air pollution in order to determine whether or not emissions units at the facility could be considered to be BART-eligible. The report explains that the following series of steps were used to identify potentially BART-eligible facilities in the WRAP region:

Step 1: Identify the facilities that are categorical sources (i.e., one of the 26 source categories);

Step 2: Identify whether or not any of the emissions units at the facility are within the date range of BART;

Step 3: Determine whether or not the potential emissions of the entire facility (all emissions units) are greater than 250 tons per year of visibility-impairing pollutants.

B. BART-Eligibility Determination

On June 15, 2005, EPA published final regulatory text and guidelines for implementing BART, including methodologies that are to be used to establish whether or not emissions units at a facility are truly BART-eligible. According to the language of the guidelines, there are three steps for determining which emissions units at a facility are considered to be BART-eligible. Those three steps are summarized as follows:

Step 1: Determine whether the plant contain emissions units in one or more of the 26 source categories:
- a. If no, then emissions units are not BART-eligible.
- b. If yes, proceed to Step 2.

Step 2: Identify the start-up dates of emissions units identified in Step 1. Determine whether the emissions units had begun operation after August 7, 1962 and were in existence on August 7, 1977:
- a. If no, then emissions units are not BART-eligible.
- b. If yes, proceed to Step 3.

Step 3: Compare the potential emissions from all emissions units identified in Steps 1 and 2. Determine whether the combined potential emissions of visibility impairing pollutants from these emissions units are greater than 250 tons per year:
- a. If no, then emissions units are not BART-eligible.
- b. If yes, then emissions units are BART-eligible.

Appendix H of the April 4, 2005, draft SSJF report that identified potentially BART-eligible sources in the WRAP Region specifically recognized a list of sources under the jurisdiction of the Arizona Department of Environmental Quality (ADEQ), the Maricopa Air Quality Department (MCAQD), the

1 See: http://www.wrapair.org/forums/ssjf/bartsources.html

Pima County Department of Environmental Quality (PDEQ) and the Pinal County Air Quality Control District (PCAQCD). Using this list as a basis, ADEQ concluded that 14 distinct sources comprised of 42 separate emissions units in Arizona were "potentially-BART-eligible".

C. Potentially Subject-to-BART

1. Background

After determining BART-eligibility, the State must then determine whether the air pollution emission unit is "potentially-subject-to-BART". EPA finalized several options that allowed States flexibility when making the determination of whether a source "emits any pollutants which may reasonably be anticipated to cause or contribute to any visibility impairment."

Option 1: All BART-eligible sources are Subject-to-BART

EPA provided the States with the discretion to consider all BART-eligible sources within the State to be "reasonably anticipated to cause or contribute" to some degree of visibility impairment in a Class I area. EPA held that this option is consistent with the American Corn Growers court's decision, as it would be an impermissible constraint of State authority for the EPA to force States to conduct individualized analyses in order to determine that a BART eligible source "emits any air pollutant which may reasonably anticipated to cause or contribute to any impairment of visibility in any [Class I] area."

Option 2: All BART-Eligible Sources Do Not Cause or Contribute to Regional Haze

EPA also provided States with the option of performing an analysis to show that the full group of BART-eligible sources in a State may not, as a whole, be reasonably anticipated to cause or contribute to any visibility impairment in Class I areas. Although the option was provided, EPA did also state that it anticipated that in most, if not all, States BART-eligible-sources are likely to cause or contribute to some level of visibility impairment in at least one Class I area.

Option 3: Case-by-Case BART Analysis

The final option that was provided to the States was to consider the individual contributions of a BART-eligible source to determine whether the facility is subject-to-BART. Specifically, EPA allowed States to choose to undertake an analysis of each BART-eligible source in the State in considering whether each such source "emit[s] any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any [Class I] area." Alternatively, States may choose to presume that all BART-eligible sources within the State meet this applicability test, but provide sources with the ability to demonstrate on a case-by-case basis that this is not the case.

2. Arizona Process

When considering the options provided by EPA, ADEQ determined that the third option is the most consistent with the American Corn Growers case, as this option provides a rebuttable method for the evaluation of the visibility impact from a single source. If the air dispersion modeling analysis shows that a facility causes or contributes to Regional Haze, then it is required to address BART. A State is also provided with flexibility under this option, as it may exempt from BART any source that is not reasonably anticipated to cause or contribute to visibility degradation in a Class I area.

As noted in Section IV.B above, fourteen Arizona facilities were determined to be potentially-BART-eligible. On June 9, 2006, ADEQ provided potential emissions information along with stack parameters for each potentially-BART-eligible facility to the WRAP's Regional Modeling Center, which performed a CALPUFF modeling analysis to determine the predicted visibility impairment apportioned to each facility.

On June 7, 2007, the WRAP's Regional Modeling Center provided ADEQ with the results of the CALPUFF modeling analysis. Based upon the CALPUFF modeling results, ADEQ determined that if a "potentially-BART-eligible" source's twenty-second highest (98th percentile) visibility impact across the three years of modeling was greater than 0.5 deciviews (dv) in any Class I area less than 300 kilometers away, the facility would be considered to contribute to impairment of visibility in that Class I area. Similarly, if the "potentially-BART-eligible" source's impact was found to be greater than 1.0 dv in any Class I area less than 300 kilometers away, the facility would be considered to cause impairment of visibility in that Class I area. In every case where a "potentially-BART-eligible" source was found to have emissions that contributed to, or caused, impairment of visibility in a Class I area, ADEQ determined that the facility was "potentially-subject-to-BART." In some cases where a facility's contributions to impairment of visibility in a Class I area were within 20% of 0.5 dv, ADEQ requested that the source provide further information demonstrating that the facility was not "potentially-subject-to-BART." As a result, eight BART-eligible facilities were determined to be potentially-subject-to-BART, and one facility was recommended for further evaluation.

On July 13, 2007, the eight sources that were potentially-subject-to-BART and the source that was recommended for further evaluation were provided with a set of three options: (i) demonstrate that the facility is not BART-eligible; (ii) demonstrate that while the facility is BART-eligible, it is not potentially-subject-to-BART as the facility does not cause or contribute to regional haze; or (iii) agree that the facility is potentially-subject-to-BART and conduct a BART analysis for the facility.

D. Subject-to-BART Determination

Once the "universe" of potentially-BART-eligible sources has been set, the State must make a determination about which of these sources are truly subject-to-BART. In order for a source to be subject-to-BART, a State must conclude that emissions of visibility impairing pollution from a BART-eligible source may reasonably be anticipated to cause or contribute to any visibility impairment in a mandatory Class I area.

As noted in Section V.C above, ADEQ's process only resulted in the determination that certain facilities are potentially-subject-to-BART. The cause for this intermediate step was that ADEQ was unable to access emissions and stack parameter information that is recommended by the EPA BART guidelines for analyzing a facility. Instead, ADEQ relied on information that was publicly available through the Title V permit applications for each of the facilities. Each of the facilities found to be potentially-subject-to-BART was provided with the opportunity to conduct a modeling analysis using emissions estimates that are reflective of steady-state operating conditions during periods of high capacity utilization. In other words, in accordance with the EPA July 6, 2005, BART guidelines, facilities were provided with the option of using of an emissions rate based on the maximum actual emissions over a 24-hour period for the most recent five year periods as an appropriate gauge of a source's potential impact. EPA explained that this would ensure that peak emission conditions are reflected, but would not overestimate a source's potential impact on any given day.

In its analysis of potentially BART-eligible sources, ADEQ identified one facility that appeared to be BART-eligible but deferred sending a letter to that facility, as representatives of the facility were already

engaged in dialogue regarding the facility's BART eligibility. Ultimately, the facility chose to demonstrate that it was never BART-eligible.

Arizona Sources That Chose to Demonstrate "Not BART-Eligible":

- TEP Irvington Generating Station

Of the nine facilities that received ADEQ's July 13, 2007, letter, five facilities provided documentation that argued that while the facility was BART-eligible, it was not potentially-subject-to-BART. Those five facilities are as follows:

Arizona Sources That Chose to Demonstrate Not "Potentially-Subject-to-BART":

- Arizona Portland Cement Company
- APS West Phoenix
- ASARCO Hayden Smelter
- Chemical Lime Nelson Lime Plant
- Freeport McMoRan Miami Smelter

Of the facilities that received ADEQ's July 13, 2007, letter, four responded that the facilities were indeed subject-to-BART and provided an BART-analysis for the BART-eligible equipment. Those four facilities are as follows:

Arizona Sources that Agreed To Be Subject-to-BART:

- Catalyst Paper
- AEPCO
- APS Cholla Power Plant
- SRP Coronado Generating Station

V. ARIZONA SOURCES THAT CHOSE TO DEMONSTRATE "NOT BART-ELIGIBLE"

A. TEP – Irvington Generating Station

On June 9, 2006, ADEQ sent a letter to the Western Regional Air Partnership's (WRAP's) Regional Modeling Center (RMC) requesting assistance in performing a CALPUFF modeling analysis for all BART-eligible sources. In the letter and supporting attachments, ADEQ identified Steam Unit I4 at Tucson Electric Power Company's (TEP's) Irvington Generating Station as potentially-BART-eligible emissions unit. The attachment to the letter went on to describe Unit I3 as also potentially-BART-eligible, as the emissions unit appeared to have been in existence in 1961, and the "in-service" date for the unit was not well documented in the files that ADEQ had reviewed.

On January 2, 2007, TEP submitted a letter to ADEQ providing information about the BART-eligibility of both Units I3 and I4. The letter explained that the issues to which it was specifically responding were:

- For Unit I3 – the date the unit began "operation"; and
- For Unit I4 – whether the coal conversion project effectively moved its "in existence" date to later than August 7, 1977.

Regarding Unit I3, TEP noted that in order for an emissions unit to be considered BART-eligible, the unit had to be "in existence" on August 7, 1977, but not "in operation" before August 7, 1962. According to the letter, Unit I3 commenced commercial operation on June 26, 1962. As documentation, TEP provided a work log from June 29, 1962, which indicates that "…Unit [I3] was placed in commercial operation on Tuesday, June 26, 1962." After reviewing this documentation, ADEQ agrees that Unit I3 was "in operation" prior to August 7, 1962, and is, therefore, not BART-eligible.

Regarding Unit I4, TEP stated that during the 1980s, Unit I4 was converted to burn coal in accordance with a prohibition order that was issued pursuant to Section 301(c) of the Power Plant and Industrial Fuel Use Act of 1978. The Final Prohibition Order became effective on September 21, 1981, as noted in Federal Register Vol. 46, p. 37960. In its January 2, 2007, letter, TEP stated that compliance with the Final Prohibition Order required TEP to reconstruct Unit I4. According to 40 CFR 51.301, Reconstruction is defined as follows:

> *Reconstruction* will be presumed to have taken place where the fixed capital cost of the new component exceeds 50 percent of the fixed capital cost of a comparable entirely new source. Any final decision as to whether reconstruction has occurred must be made in accordance with the provisions of § 60.15(f)(1) through (3) of this title.

TEP stated that because Unit I4 was reconstructed after August 7, 1977, the Unit was not "in existence" before August 7, 1977, and, therefore, must be considered "not BART-eligible".

In an electronic mail that was sent to a representative of TEP on May 15, 2007, ADEQ requested that TEP provide additional documentation that demonstrated that Unit I4 was reconstructed in the 1980s. On July 3, 2007, TEP submitted a supplemental letter to ADEQ, with the documentation that ADEQ had requested.

According to the July 3, 2007, the total cost for the Unit I4 coal conversion was reported in the 1987 FERC Form No. 1 to be approximately $125 million dollars, including the Unit I4 portion of the facilities that are shared by Units I3 and I4 (i.e., coal handling facility, water treatment, ash storage and disposal,

etc.). In January of 1988, Unit I4 was sold in a leaseback arrangement for $152 million, which TEP argues approximates the fair market value for the Unit. TEP stated that because Unit I4 was essentially in new condition following the coal conversion, it is reasonable to conclude that the construction of a comparable new unit would not be significantly greater than $152 million. Based upon this information, TEP stated that the coal conversion cost was significantly greater than 50% of the fixed capital cost of a comparable, entirely new unit. As a result, TEP concluded that Unit I4 was reconstructed in the 1980s, effectively changing the "in existence" date to after August 7, 1977. As a result, TEP concluded that Unit I4 was "not BART-eligible".

After reviewing the information that was provided by TEP, including the relevant portions of the December 31, 1987, FERC Form No. 1 Annual Report of Major Electric Utilities, Licensees and Others, TEP's 1987 Annual Report, and a work sheet entitled "Estimated Cost of Irvington Unit 4 Coal Conversion", ADEQ concurs that the cost of modifying TEP Irvington's Unit I4 is greater than 50 percent of the fixed capital cost of a comparable, entirely new source, and that Unit I4 was reconstructed in the 1980s.

In Federal Register, Vol. 70, No. 128, Wednesday, July 6, 2005, pages 39110-39112, EPA discusses Step 2 in determining whether a facility is BART-eligible. According to the background statement in the guidance:

> "Step 2 also addresses the treatment of 'reconstruction' and 'modifications.' Under the definition of BART-eligible facility, sources which were in operation before 1962 but reconstructed during the 1962 to 1977 time period are treated as new sources as of the time of reconstruction."
>
> The footnote attached to this statement goes on to state:
>
> "However, sources reconstructed after 1977, which reconstruction had gone through NSR/PSD permitting, are not BART-eligible."

At the time of TEP's 1987 reconstruction of Unit I4, reconstruction of most units at the Irvington Generating Station would have normally triggered the New Source Review (NSR) or Prevention of Significant Deterioration (PSD) permitting process. As TEP points out in its correspondence, however, TEP only commenced the reconstruction as a result of the an order that was issued pursuant to Section 301(c) of the Power Plant and Industrial Fuel Use Act of 1978. Arizona's PSD rule (Arizona Administrative Code, Title 9, Article 3, Rule 304 or A.A.C. R9-3-304) was approved into the State Implementation Plan in 1983. According to the PSD rule, all "major modifications" were required to obtain a PSD permit prior to construction and operation of the facility. The definitions that support this rule were found in A.A.C. R9-3-101. According to R9-3-101(91)2 a major modification is defined as follows:

> "Major modification" means any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under this Chapter.
>
> a. …
> b. For the purposes of this definition the following shall not be considered a physical change or change in the method of operation:

---

2 http://yosemite.epa.gov/R9/r9sips.nsf/AgencyProvision/ABAB0C337F5775248825698C0064E741/$file/az+deq+r9-3-101.pdf?OpenElement

i. …
ii. Use of an alternative fuel or raw material by reason of an order under Sections 2 (a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) or by reason of a natural gas curtailment plan pursuant to the Federal Power Act;
iii. …
iv. …
v. …
vi. …
vii. …"

Pursuant to A.A.C. R9-3-101(90)(b)(ii), TEP's reconstruction of Unit I4 did not constitute a major modification at the time that the reconstruction occurred, and therefore Arizona's PSD rule did not apply. TEP's January 2, 2007, letter states that "TEP believes that PSD is immaterial to BART eligibility, as Reconstruction under the RHR makes no mention of PSD or any of its provisions. In fact, no where in its rules[footnote omitted] governing BART eligibility, does it state that being subject to PSD is a condition of Reconstruction under the RHR."

ADEQ has reviewed 40 CFR Part 51 Appendix Y, Section II.A.2 and has determined that EPA has addressed this issue:

"What is a 'reconstructed source?'

1. Under a number of CAA programs, an existing source which is completely or substantially rebuilt is treated as a new source. **Such 'reconstructed' sources are treated as new sources as of the time of the reconstruction.** Consistent with this overall approach to reconstruction, the definition of BART-eligible facility (reflected in detail in the definition of 'existing stationary facility') includes consideration of sources that were in operation before August 7, 1962, but were reconstructed during the August 7, 1962 to August 7, 1977 time period.

2. …

3. …

4. The 'in-operation' and 'in existence' tests apply to reconstructed sources. If an emissions unit was reconstructed and began actual operation before August 7, 1962, it is not BART-eligible. Similarly, any emissions unit for which a reconstruction 'commenced' after August 7, 1977, is not BART-eligible." (emphasis added)

ADEQ has determined that EPA's guidance does not specifically address situations where a facility was reconstructed after August 7, 1977, but was exempted from PSD review at the time that reconstruction occurred. ADEQ concludes, however, that the plain reading of EPA's guidance is most appropriate, and has determined that it is appropriate to treat reconstructed sources as new sources as of the time of the reconstruction. As a result, ADEQ concurs that the reconstructed Unit I4 at TEP's Irvington Generating Station was not "in existence" prior to August 7, 1977. Therefore, ADEQ has determined that there are no BART-eligible emissions units at TEP's Irvington Generating Station.

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VI. ARIZONA SOURCES THAT CHOSE TO DEMONSTRATE NOT "POTENTIALLY-SUBJECT-TO-BART"

A. Arizona Portland Cement Company

On June 13, 2007, ADEQ sent a letter to Arizona Portland Cement Company (APCC) indicating that Kiln 4 was "potentially-subject-to-BART" for NOx and PM emissions. ADEQ based the letter on its analysis of the facility as described in a June 9, 2006, letter to the Western Governor's Association; and its review of the February 28, 2002, Amended Application for a Class I Permit, the 2005 Significant Revision Application, and observations from performance testing results which indicated that Kiln 4 had the following potential NO_X and PM emissions (Table 6.1):

Table 6.1 – Kiln 4 Emissions

Emissions Unit	NO_X Emissions (lb/hr)	PM Emissions (lb/hr)
Kiln 4	540.10	11.39

According to the letter, the WRAP's Regional Modeling Center conducted an air dispersion modeling analysis using CALPUFF which demonstrated that the maximum 98th percentile three-year average total impact from the facility was 0.40 dv. These visibility impacts were expected to occur in both the Saguaro National Monument and the Galiuro Wilderness area.

On September 10, 2007, APCC submitted a letter to ADEQ stating that it agreed that Kiln 4 was the only emissions unit that was in operation at the facility that was BART-eligible. The letter went on to state that because the 98th percentile three-year average total impact from this emissions unit was 0.40 dv, concluded that Kiln 4 does not "cause" or "contribute to" visibility impairment in any Class I area.

When weighing APCC's response, ADEQ also gave consideration to additional extenuating circumstances regarding Kiln 4. In 1998, APCC obtained a significant permit revision from ADEQ, allowing the company to modify portions of Kiln 4 in an effort to increase the amount of clinker that the company could produce while taking limitations designed to ensure that there was not a significant net emissions increase as a result of the project. After completing Phase I of the changes to Kiln 4, APCC determined that it was not realizing the additional clinker production projected to occur as a result of the modification. In 2002 and 2003, APCC approached ADEQ with a new application for a permit revision, requesting the authority to construct a new Kiln 5 rather than finalizing the modifications to Kiln 4.

In 2003, during its review of a proposed Title V permit that would have provided APCC with the flexibility to choose between three operating scenarios, including the construction of Kiln 5, EPA identified an error in APCC's fugitive dust emissions calculations. According to EPA's calculations, the modifications that were completed in 1998 should have gone through New Source Review. As a result, EPA issued a Notice of Violation to APCC, alleging that the company avoided New Source Review when completing modifications to Kiln 4 in 1998. EPA also objected to the issuance of the proposed Title V permit, but later lifted its objection after ADEQ removed the alternative operating scenarios that would have allowed for further modification of the facility. A consent decree is being finalized between APCC and EPA to resolve the issue.

In 2008, ADEQ issued a new permit to APCC which would have allowed the facility to stop operations at all four existing kilns and construct and operate a new Kiln 6. The 18 month construction window ended in June 2010 and APCC has since reapplied for a permit for the Kiln 6 expansion.

Based upon the consideration of the history of this facility, and the maximum 98th percentile three-year average impact from all pollutants is less than 0.5 dv, ADEQ concurs that APCC is not subject-to-BART.

B. APS West Phoenix

On June 13, 2007, ADEQ sent a letter to the Arizona Power Service Company's West Phoenix Generating Station indicating that three emissions units, Combined Cycle Units 1 through 3, were "potentially-subject-to-BART" for NO_X emissions. ADEQ based the letter on its analysis of the facility as described in a June 9, 2006, letter to the Western Governor's Association; and its review of the July 2000 Title V Operating Permit Application, and February 24, 2006 Significant Revision Application which showed that the facility had potential NO_X emissions as follows:

Table 6.2 – APS West Phoenix NO_X Emissions

Emissions Unit	NO_X Emissions (lb/hr)	NO_X Emissions (tons/year)
Combined Cycle Unit 1 (NG)[a]	255.80	1,120
Combined Cycle Unit 2 (NG)[a]	255.80	1,120
Combined Cycle Unit 3 (SR app)[c]	405.10	1,774
Combined Cycle Unit 1 (oil)[b]	763.00	3,342
Combined Cycle Unit 2 (oil)[b]	763.00	3,342
Combined Cycle Unit 3 (SR app)[c]	405.10	1,774

a. NG indicates potential emissions while burning natural gas
b. Oil indicates potential emissions while burning oil
c. SR app means that the potential emissions were to be limited as proposed in a significant permit revision application that was submitted on February 24, 2006.

On July 30, 2007, APS West Phoenix provided documentation to ADEQ demonstrating that the facility had accepted federally-enforceable conditions in Maricopa County Air Quality Permit Number V95-006 that placed limits on emissions of air pollutants from the facility. Specifically, the permit states in Table 1 that the "Allowable Combined Emissions for CC3, CC4, CC5, the CC4 and CC5 Cooling Towers, and the Clayton Boiler Emissions Units" for NO_X was 405.1 tons per year. The same permit also limits the short term NO_X emissions for Combined Cycle Unit 3 to no more than 34.3 pounds per hour.

On September 6, 2007, APS West Phoenix submitted a letter to ADEQ identifying errors in the underlying assumptions that were the basis of ADEQ's June 13, 2007, letter. Specifically, the facility identified the following issues:

- The data used as the pound per hour emission rate for Combined Cycle Unit 3 were actually tons per year emissions limitations for multiple emissions units, rather than a pound per hour emission rate for that same unit;
- Combined Cycle Unit 3 is equipped with a Selective Catalytic Reduction (SCR) unit;
- Combined Cycle Unit 3's stack height was assumed to be 54 feet, whereas the actual stack height for the unit is 82 feet;

- The air dispersion modeling analysis used West Phoenix emissions rates associated with fuel oil combustion. The Maricopa County Air Quality Department prohibits the combustion of fuel oil except during periods of natural gas curtailments, and should not have been considered the normal operating scenario.

APS West Phoenix stated that it would fix each of these assumptions, and resubmit an air dispersion modeling analysis that was performed by the WRAP's Regional Modeling Center with the adjusted values.

On October 7, 2007, APS West Phoenix submitted a second letter to ADEQ. In that letter, APS West Phoenix explained that it agreed with ADEQ's assessment that the Combined Cycle Units CC1, CC2 and CC3 were BART-eligible. APS West Phoenix stated, however, that after correcting the air dispersion modeling analysis using the assumptions identified above, the 98th percentile visibility impacts that ADEQ had predicted in the Superstition Wilderness and the Mazatzal Wilderness areas dropped from 0.69 dv and 0.64 dv, to 0.24 dv and 0.31dv respectively.

Based on the revised air dispersion modeling analysis that was submitted on October 7, 2007, APS West Phoenix stated that it did not cause or contribute to regional haze in a Class I area, and therefore was not subject-to-BART. Based upon its review of the information that has been submitted, and a review of the conditions in Maricopa County Air Quality Permit V95-006, ADEQ concurs that this facility is not subject-to-BART.

C. ASARCO Hayden Smelter

On June 13, 2007, ADEQ sent a letter to the ASARCO Hayden Smelter indicating that Converters 1 through 5, and Anode Furnaces 1 through 3 were "potentially-subject-to-BART" for SO_2 and PM emissions. ADEQ based the letter on its analysis of the facility as described in a June 9, 2006, letter to the Western Governor's Association; and its review of the 1994 Application for a Class I Permit which showed that the facility had potential SO_2 and PM emissions as follows (Table 6.3):

Table 6.3 – ADEQ Modeled Emissions for ASARCO Hayden

Emissions Unit	SO_2 emissions (lb/hr)	PM emissions (lb/hr)
Acid Plant Main Stack (Converters 1-5, Anode Furnace 1-3)	114,000	4.22
Annulus Main Stack (bypass for main stack)	114,000	15.78
Flash Furnaces and Converter Fugitives	2,991	16.42

In Attachment 3 to the June 13, 2007, letter, ADEQ also identified the equipment that, according to Title V Permit 1000042, was potentially BART-eligible. That equipment included the following:

- Converters (5) – constructed in 1969
- Anode Furnaces 1-3 – constructed in 1971

Finally, ADEQ's analysis revealed that in 2004, the actual emissions of PM_{10} from the facility was 157.3 tons per year. Because ADEQ was uncertain whether this number was representative of overall emissions of PM_{10} from the ASARCO Hayden Smelter through the years, the potential emission rate information for

both SO_x and PM was submitted to the WRAP's Regional Modeling Center. Based upon the information that ADEQ submitted, the WRAP's Regional Modeling Center provided ADEQ with the following modeled impacts:

Table 6.4 – WRAP Modeled Impact from ASARCO Hayden		
Class I Area	**98th % 3 Yr Avg. PM_{10} Impact (dv)**	**98th % 3 Yr Avg. SO_2 Impact (dv)**
Galiuro Wilderness	0.53	2.23
Superstition Wilderness	0.41	2.39
Sierra Ancha Wilderness	0.13	1.46
Saguaro NM	0.23	1.64
Mazatzal Wilderness	0.09	1.22
Mount Baldy Wilderness	0.04	0.76
Pine Mountain Wilderness	0.05	0.93
Chiricahua NM	0.13	1.39
Gila Wilderness	0.05	0.78
Petrified Forest NP	0.04	0.78
Sycamore Canyon	0.03	0.70

As a result, ADEQ determined that the facility was BART-eligible for PM_{10} and SO_2 emissions.

On October 1, 2007, ASARCO LLC submitted a letter to ADEQ stating that the company has already installed BART-equivalent controls on the necessary emissions units, and that further control was not necessary.

In its review of ADEQ's analysis, ASARCO pointed out that errors were made in ADEQ's identification of the BART-eligible source. According to their own research, ASARCO determined that the BART-eligible emissions units at their facility were as follows:

- Converters (3)
  - Three converters were in operation prior to 1962;
  - One converter was enlarged from 13 x 32 feet to 13 x 35 feet in 1965
  - Converters #1 and #4 were added in 1968.
- Anode Furnaces #1 and #2 – Constructed in 1972
  - Anode Furnace #0 was constructed in 2001

As a result, ASARCO went on to state that it concluded that only two or three of the converters were considered to be BART-eligible. ASARCO stated that because the air dispersion modeling analysis was performed based upon the use of the potential to emit from the entire facility, the predicted impacts from the facility were overstated. Instead, ASARCO stated that the following emissions should have been modeled (Table 6.5):

Table 6.5 – ASARCO Modeled Emissions for ASARCO Hayden			
Unit	**NO_x (tpy)**	**PM_{10} (tpy)**	**SO_2 (tpy)**
Total for BART-eligible Emission Units	21.4[a] 23.3[b]	61.1[a] 70.0[b]	6,903[a] 10,337[b]

a. 2 converters
b. 3 converters

ASARCO stated that "[i]f [PM] emissions from the BART-eligible units alone are modeled the visibility impact would be below the 0.5 dv threshold. Therefore, BART determination is necessary only for SO_2."

ADEQ has reviewed its documentation, and ASARCO's arguments regarding BART eligibility, and ADEQ agrees with ASARCO's assessment of its BART-eligible emissions unit, with the clarification that the converter that was modified in 1965 is considered BART-eligible.

At the time that ADEQ was assessing BART eligibility, ADEQ based its analysis on the potential emissions from the entire facility, as it was not possible for ADEQ staff to apportion emissions to the specific emissions units based upon the information that had been submitted by ASARCO. As a result, ADEQ provided all of the potential PM and SO_2 emissions to the Regional Modeling Center, understanding that ASARCO would have the expertise necessary to apportion emissions to each emissions unit that was BART-eligible.

ASARCO's October 1, 2007, letter, however, lacked documentation that demonstrated how ASARCO apportioned the emissions to the BART-eligible equipment. ADEQ's analysis of the table only revealed that the apportionment of emissions to the emissions units is not linear, making it too difficult for ADEQ to replicate the submitted calculations. ADEQ, however, is in the process of reviewing ASARCO's application for renewing its existing Title V permit. As part of its review, ADEQ's staff has estimated the potential emissions from the emissions units at the facility. ADEQ's calculations reveal that the potential to emit PM_{10} from the entire primary copper smelter process is 213 tons per year. As noted above, only three converters and two anode furnaces are considered to be BART-eligible emissions units at the facility. Each of these emissions units is located within the primary copper smelting process. Since non-BART-eligible emissions units contribute to the total potential emissions of 213 tons per year, ADEQ concluded that the BART-eligible equipment at the ASARCO Hayden Primary Copper Smelter is not capable of emitting more than 250 tons per year of PM_{10}. As a result, ADEQ determined that the emissions units at the ASARCO smelter are not BART-eligible for PM_{10} emissions.

With respect to SO2 emissions, ASARCO stated the following:

> "During the deliberations of the Market Trading forum [sic] of the Western Regional Air Partnership (WRAP), all parties involved including ADEQ and the U. S. Environmental Protection Agency (EPA), agreed that the controls and emissions limitation for primary copper smelters already met BART for SO_2."

ADEQ understands that there may have been, at one time, a general principle to which U.S. EPA, ADEQ, and perhaps other parties agreed regarding the controls and emissions limitation for primary copper smelters. According to ADEQ's interpretation of the Regional Haze Rules, and its application of EPA's BART guidelines, however, general principles are not enough to exempt a facility from a BART analysis. Instead, ADEQ has determined that it is necessary to evaluate ASARCO's facility for the potential applicability of BART.

D. Chemical Lime Company – Nelson Lime Plant

On June 13, 2007, ADEQ sent a letter to Chemical Lime Company's (CLC's) Nelson lime plant indicating that Kilns 1 and 2 were "potentially-subject-to-BART" for NO_X and SO_2 emissions. ADEQ based the letter on its analysis of the facility as described in a June 9, 2006, letter to the Western Governor's Association; and its review of the November 30, 2001, Amended Application for a Class I permit, as well as air quality control permit number 36425 which showed that the facility had potential NO_X and SO_2 emissions as follows (Table 6.6):

Table 6.6 – ADEQ Modeled Emissions for CLC Nelson

Emissions Unit	SO_2 Emissions (lb/hr)	NO_X Emissions (lb/hr)
Kiln 1	215.59	122.14
Kiln 2	484.27	182.78

Using these emissions rates, and modeling information about the facility from the sources identified above, the WRAP's Regional Modeling Center provided ADEQ with the following modeled impacts (Table 6.7):

Table 6.7 – WRAP Modeled Impact from CLC Nelson

Class I Area	98th % 3 Yr Avg. NO_X Impact (dv)	98th % 3 Yr Avg. SO_2 Impact (dv)	98th % 3 Yr Avg. Total Impact (dv)
Grand Canyon NP	0.38	0.32	0.74
Sycamore Canyon WA	0.06	0.13	0.18
Zion NP	0.10	0.11	0.20
Pine Mountain Wilderness	0.03	0.08	0.10
Mazatzal Wilderness	0.03	0.08	0.11
Bryce Canyon NP	0.05	0.07	0.11
Joshua Tree NM	0.03	0.12	0.14
Sierra Ancha Wilderness	0.02	0.06	0.07
Superstition Wilderness	0.02	0.07	0.08

On September 21, 2007, CLC submitted a letter to ADEQ along with a new modeling analysis indicating that "…the 3-year average of the 8th highest visibility change is less than 0.5 dv in all Class I areas." Based upon its review of the new modeling analysis, Chemical Lime concluded that the Nelson facility did not cause or contribute to visibility impairment in any Class I area, and that the emissions units were, therefore, not subject-to-BART.

According to the documentation submitted in support of the new modeling analysis, Chemical Lime estimated its emission rates of NOx, SO_2 and PM for the BART applicability modeling analysis using the maximum production rates achieved by each kiln during the meteorological period that was modeled (a method which can result in the over prediction of actual impacts on an annual basis), and from using representative emissions factors that were derived from source testing performed at the Nelson facility. The emission rates that CLC modeled are as follows (Table 6.8):

Table 6.8 – CLC Modeled Emissions for CLC Nelson		
Emissions Unit	**SO_2 Emissions (lb/hr)**	**NO_X Emissions (lb/hr)**
Kiln 1	117.8	95.23
Kiln 2	375.5	99.20

According to ADEQ's review of the modeling analysis, none of the other fixed parameters (i.e., elevation, stack height, stack diameter, exhaust gas velocity, and exit temperature) were significantly modified in CLC's analysis. The only difference noted was that the elevation of the facility used by ADEQ was 1,570.7 meters above sea level, whereas the company reported the elevation to be 1,570.3 meters above sea level. Because the difference between the two parameters was less than half of a meter (approximately 1.5 feet) ADEQ determined that the change was not significant.

The resulting modeling impacts from the screening assessment performed by CLC, as documented in the September 21, 2007, submission and a May 28, 2009, electronic mail to ADEQ, were as follows (Table 6.9):

Table 6.9 – Modeled Impact from CLC Nelson			
Class I Area	**98^{th} % 3 Yr Avg. NO_X Impact (dv)**	**98^{th} % 3 YR Avg. SO_2 Impact (dv)**	**98^{th} % 3 Yr Avg. Total Impact (dv)**
Grand Canyon NP	0.291	0.205	0.498
Sycamore Canyon WA	0.015	0.107	0.123
Zion NP	0.054	0.081	0.136
Pine Mountain Wilderness	0.003	0.069	0.072
Mazatzal Wilderness	0.017	0.056	0.073
Bryce Canyon NP	0.026	0.048	0.074
Joshua Tree NM	0.014	0.093	0.108
Sierra Ancha Wilderness	0.010	0.039	0.049
Superstition Wilderness	0.009	0.045	0.054

As can be seen from the table above, the company's modeling analysis showed that the 98th percentile, three-year average total impact from the plant was predicted to be less than 0.5 dv for every Class I area within 300 kilometers of the facility. The company also recognized, however, that the predicted impacts within the Grand Canyon were marginally below 0.5 dv. As a result, the company stated that "[a]lthough the maximum visibility change obtained in the screening modeling analysis is not equal to or greater than the 0.5 dv contribution threshold, a refined analysis was performed in which light extinction in the Grand Canyon National Park was calculated using the CALPOST-IMPROVE implementation of the revised light extinction algorithm…" Based upon the refined analysis, the 98th percentile (8th highest) Visibility Change in the Grand Canyon was calculated to be as follows (Table 6.10):

Table 6.10 – Modeled Impact from CLC Nelson at the Grand Canyon NP				
Class I Area	98th Percentile (8th highest) Visibility Change (dv)			
	2001	2002	2003	Average
Grand Canyon NP	0.417	0.379	0.585	0.460

Based upon its refined visibility change analysis, CLC determined that the visibility change attributable to the Nelson facility is below 0.5 dv, and it concluded that the facility does not significantly contribute to visibility impairment within the Grand Canyon National Park. As a result, CLC determined that the results of the analysis indicated that the 3-year average of the 8th highest visibility change was less than 0.5 dv in all Class I areas within 300 km of the facility, and concluded that its Nelson facility was not-subject-to-BART.

Based upon the consideration of the analysis performed for this facility, CLC's conservative approach for estimating emissions impacts during the meteorological period, and the maximum 98th percentile three-year average impact from all pollutants is less than 0.5 dv, ADEQ concurs that the Chemical Lime Company's Nelson Lime Plant is not subject-to-BART.

E. Freeport McMoRan Miami Smelter

On June 13, 2007, ADEQ sent a letter to Freeport McMoRan Miami Inc (FMMI) indicating that the Miami Smelter Converters 1 through 5; the Remelt Vessel and the Acid Plant were "potentially-subject-to-BART" for SO_2 and PM emissions. ADEQ based the letter on its analysis of the facility as described in a June 9, 2006, letter to the Western Governor's Association; and its review of the Air Quality Permit Number 1000046, and the application for Air Quality Permit Number 1000046 which showed that the facility had potential SO_2 and PM emissions as follows (Table 6.11):

6.11 – ADEQ Modeled Emissions from FMMI		
Emissions Unit	SO_2 Emissions (lb/hr)	PM Emissions (lb/hr)
Acid Plant Tailgas Stack (Converters 1-5)	820.0	20.40
Vent Fume Stack (Electric Furnace Stack)	312.0	56.30
Shaft Furnace Stack	0.030	4.110
Smelter Fugitives	1288	48.55
Rod Plant Fugitives	0.000	0.100

On July 17, 2007, FMMI responded stating that "although, we do not disagree with the results that the Miami facility is subject-to-BART, because the visibility impact was greater than 0.5 dv at the Superstition Wilderness area, we would like to point out some corrections in the emissions points and emissions used in the modeling." According to the letter, FMMI disputed the stack height, diameter and velocity values that were used for the Vent Fume Stack and the emissions release point and temperature for fugitive emissions from the smelter that ADEQ provided to the WRAP's RMC in its June 9, 2006, letter. FMMI also reported that the Rod Plant shaft furnace should not have been included as part of the smelter, and the acid plant preheater was installed in 1991 as part of the company's ISA modification.

On August 3, 2007, FMMI provided another letter to ADEQ, presenting several bases for streamlining the BART review for the FMMI Smelter. According to the letter, FMMI stated that it believed that only the following emissions units at the facility constituted the "source subject-to-BART":

- The Electric Furnace (installed in 1974)
- The four Hoboken Converters (Converters Nos. 2-5) (installed in 1974) ; and
- The Remelt/mold pouring Vessel (installed in approx. 1974)

FMMI then provided ADEQ with information regarding the five steps that EPA proposed in its BART guidance, but indicated that EPA provided the option for streamlining the review. According to FMMI's letter, EPA's guidance at 40 CFR Part 51, Appendix Y, § IV(C) states:

> "For VOC and PM sources subject to MACT standards, States may streamline the analysis by including a discussion of the MACT controls and whether any major new technologies have been developed subsequent to the MACT standards."

FMMI's letter goes on to provide a "streamlined review" of emissions from relevant emissions units at the FMMI smelter, and justification for the Rod Plant Shaft Furnace being separated from the BART-eligible source, as this furnace is not part of a listed source category.

After verbal discussions with ADEQ staff regarding the August 3, 2007, letter, FMMI submitted a final letter regarding the matter to ADEQ on November 29, 2007. In this letter, FMMI provided additional information to supplement the August 3, 2007, letter. In the letter, FMMI provides additional citations for the streamlined BART reviews for SO_2 and PM emissions at the Miami Smelter.

After reviewing the information that was submitted by FMMI, ADEQ agrees it is necessary to evaluate FMMI's facility for the potential applicability of BART through its process for conducting a BART analysis.

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VII. ARIZONA SOURCES THAT REQUIRED A BART ANALYSIS

Pursuant to the discussion in the previous Section, the following six facilities were identified as having to conduct a BART analyses. Due to the case-by-case nature of the BART analyses, ADEQ has included specific sections in this technical support documents for each of these facilities. A brief summary of the circumstances leading to ADEQ's subject-to-BART determinations are as follows:

A. Catalyst Paper (Snowflake) Inc. (CPSI) formerly Abitibi Consolidated

On June 13, 2007, ADEQ sent a letter to Abitibi Consolidated indicating that Power Boiler 2, a coal-fired boiler at the paper and pulp mill was "potentially-subject-to-BART" for SO_2 and NO_X emissions. ADEQ based the letter on its analysis of the facility as described in a June 9, 2006, letter to the Western Governor's Association, and its review of the Title V Permit Application –Amended Version submitted in March 2000 which showed that the facility had potential NO_X and SO_2 emissions as follows (Table 7.1):

Table 7.1 – ADEQ Modeled Emissions for CPSI		
Emissions Unit	**NO_X Emissions (lb/hr)**	**SO_2 Emissions (lb/hr)**
Power Boiler 2	555.00	915.00

On October 23, 2007, Abitibi Consolidated provided a BART analyses to ADEQ. ADEQ's analysis and BART determination for CPSI can be found in Section IX of this document.

B. Arizona Electric Power Cooperative, Inc. - Apache Generating Station

On June 13, 2007, ADEQ sent a letter to Arizona Electric Power Cooperative Inc.'s (AEPCO's) Apache Generating Station indicating that Steam Units 1 through 3 were "potentially-subject-to-BART" for NO_X and SO_2 emissions. ADEQ based the letter on its analysis of the facility as described in a June 9, 2006, letter to the Western Governor's Association; and its review of the Air Quality Permit Number 35043, and the January 6, 2005, application for Class I Permit Renewal, which showed that the facility had potential NO_X and SO_2 emissions as follows (Table 7.2):

Table 7.2 – ADEQ Modeled Emissions from AEPCO		
Emissions Unit	**NO_X Emissions (lb/hr)**	**SO_2 Emissions (lb/hr)**
Steam Unit #1	264.90	0.57
Steam Unit #2	576.47	1.24
Steam Unit #3	576.47	1.24

In July of 2007, AEPCO scheduled a meeting with ADEQ to discuss its concurrence that the facility was subject-to-BART. In the meeting, AEPCO indicated that the information that was provided to the WRAP's RMC was based upon Steam Units #2 and #3 burning natural gas, rather than coal. AEPCO discussed a proposed modeling protocol with ADEQ, and explained that when modeling its baseline conditions, AEPCO would use the emission rates associated with burning coal at the facility.

On January 2, 2008, AEPCO provided its BART analysis to ADEQ. ADEQ's analysis and BART determination for AEPCO's can be found in Section XI of this document.

C. APS Cholla Power Plant

On June 13, 2007, ADEQ sent a letter to Arizona Public Service's (APS's) Cholla Generating Station indicating that Steam Units 1 through 4 were "potentially-subject-to-BART" for NO_X, PM, and SO_2 emissions. ADEQ based the letter on its analysis of the facility as described in a June 9, 2006, letter to the Western Governor's Association, and its review of the application for Air Quality Permit Number 46353 (Table 7.3):

Table 7.3 – ADEQ Modeled Emissions from APS Cholla

Emissions Unit	NO_X Emissions (lb/hr)	PM Emissions (lb/hr)	SO_2 Emissions (lb/hr)
Unit #1	279.40	38.10	304.8
Unit #2	646.40	293.80	705.10
Unit #3	644.40	87.90	351.50
Unit #4	1,086.80	384.10	3,414.40

In August of 2007, representatives of APS's Cholla Generating Station met with representatives of ADEQ to discuss some outstanding questions that the company had regarding ADEQ's analysis. During the course of that meeting, APS provided a copy of Arizona Public Service Company Correspondence that was sent to Gus Hansen, Supt. at Cholla S.E.S. entitled "Operating Notes for May 1962". According to information provided by this document, "[o]n Tuesday, May 1, 1962, unit [#1] placed into commercial operation." As a result, APS argued that Unit #1 was "in operation" prior to August 7, 1962, and therefore was not BART-eligible. After reviewing this documentation, ADEQ concurs that Unit #1 was never BART-eligible.

On September 13, 2007, APS provided a letter to ADEQ providing a schedule for the submission of a modeling protocol and conducting a BART analysis with the goal of providing the final BART analysis on December 14, 2007. In December of 2007, ADEQ received the BART analysis. ADEQ's analysis and BART determination for the APS Cholla Power Plant can be found in Section XI of this document.

D. ASARCO Hayden Smelter

As discussed in Section VI.C of this document, ADEQ has determined that a BART analysis regarding SO_2 emissions from this facility must be completed. ADEQ's review and determination based upon its own analysis of the facts and the information that ASARCO had provided can be found in Section XII of this document.

E. Freeport-McMoRan Miami Smelter

As discussed in Section VI.E of this document, ADEQ has determined that a BART analysis regarding PM and SO_2 emissions from this facility must be completed. ADEQ's review and determination based upon its own analysis of the facts and the information that Freeport-McMoRan Miami Inc. had provided can be found in Section XIII of this document.

F. SRP Coronado Generating Station

On June 13, 2007, ADEQ sent a letter to Salt River Project's (SRP's) Coronado Generating Station indicating that Units 1 and 2 were "potentially-subject-to-BART" for PM, SO_2 and NO_X emissions. ADEQ based the letter on its analysis of the facility as described in a June 9, 2006, letter to the Western Governor's Association, and its review of the August 21, 2003 Application for Class I Permit Renewal which showed that the facility had potential NO_X, PM, and SO_2 emissions as follows (Table 7.4):

Table 7.4 – ADEQ Modeled Emissions for SRP Coronado

Emissions Unit	NO_X Emissions (lb/hr)	PM Emissions (lb/hr)	SO_2 Emissions (lb/hr)
Unit #1	3,303	472	3,775
Unit #2	3,303	472	3,775

On August 22, 2007, representatives of SRP's Coronado Generating Station met with ADEQ to discuss issues that were unique to the Coronado Generating Station, including a potential settlement with EPA regarding alleged New Source Review violations that would address NO_X and SO_2 emissions. In addition, the company provided a proposed response to ADEQ's request for a BART analysis.

In February 2008, SRP provided its BART analysis to ADEQ. On August 12, 2008, EPA announced a "…major Clean Air Act (CAA) New Source Review (NSR) settlement agreement with [SRP]…" EPA explained that "[u]nder the settlement, SRP will spend over $400 million between now and June 2014, to install state-of-the-art pollution control technology for the reduction of sulfur dioxide (SO_2) and nitrogen oxides (NO_x)."

ADEQ's analysis and BART determination for the SRP Coronado Generating Station can be found in Section XIV of this document.

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VIII. ARIZONA BART DETERMINATION PROCESS

Clean Air Act § 169A(g)(7) directs States to consider five factors in making BART determinations. The regional haze rule codified these factors in 40 CFR § 51.308(e)(1)(ii)(B), which directs States to identify the "best system of continuous emissions control technology" taking into account "the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, and the remaining useful life of the source."

The visibility BART regulations define BART as meaning "…an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by … [a BART-eligible source]. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control requirement in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."

In its guidance, EPA was clear that each State must determine the appropriate level of BART control for each source that is determined to be subject-to-BART. In making a BART determination, a State must consider the following factors:

- The costs of compliance;
- The energy and non-air quality environmental impacts of compliance;
- Any existing pollution control technology in use at the source;
- The remaining useful life of the source; and
- The degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

It appears to ADEQ that BART is a close kin to Best Available Control Technology (BACT). Both control technology requirements are based upon similar concepts, including the fact that both are conducted on a case-by-case basis, and both may constitute the application of production processes or available methods, systems and techniques to reduce air pollution emissions. The most significant difference between the two appears to be that BART must accommodate issues associated with retrofitting existing equipment with new air pollution controls that were not included in the initial design of the facility. Since the concepts between the two technology requirements are reasonably similar, ADEQ has determined that it is reasonable method for conducting a BART analysis is following the BACT methodology, taking specific care to address all five of the BART factors.

The Department's framework for performing a BART analysis comprises the following seven key steps:

1. Identify the existing control technologies in use at the source (BART factor 3);
2. Identify all available retrofit control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;
3. Eliminate all technically infeasible control technologies;
4. Evaluate control effectiveness of remaining technologies;
5. Evaluate energy and non-air quality environmental impacts and document results (BART factors 1, 2 and 4); and
6. Evaluate visibility impacts (BART factor 5).
7. Select BART

Materials considered by the applicant and by the Department in identifying and evaluating available control options include the following:

- Entries in the RACT/BACT/LAER Clearinghouse (RBLC) maintained by the U.S. EPA, is the most comprehensive and up-to-date listing of control technology determinations available;
- Information provided by pollution control equipment vendors;
- Information provided by industry representatives; and
- Information provided by other Regional Planning Organizations and State permitting authorities.

Step 1: Identify the Existing Control Technologies in Use at the Source

This step is in addition to the five steps that are recommended in Section IV.D of 40 CFR Part 51, Appendix Y ("EPA's BART guidelines"). Of the four facilities that have agreed that they are "potentially-subject-to-BART", two are already in a process of designing or installing new air pollution control devices on emissions units that are "potentially-subject-to-BART". Since the installation of these controls was not required by BART, ADEQ determined that it was appropriate to include a step that described the existing control technologies that provide the baseline against which BART will be judged.

Step 2: Identify All Available Retrofit Control Options

This step is functionally equivalent to Step 1 in EPA's BART guidelines.

At the outset of any BART analysis, EPA's guidelines suggest that States should consider all control options that have potential application to the emissions unit, regardless of technical feasibility. This includes having an understanding of other required controls, including those technologies that are required under BACT or Lowest Achievable Emissions Rate (LAER) determinations, pollution prevention practices, the use of other add-on controls, and upgrades to existing air pollution controls that are already in place. As with BACT and LAER determinations, control alternatives can also take into account technology transfer of controls that have been applied to similar source categories. Unlike some permitting authorities' BACT and LAER procedures, however, BART does not contain a requirement to redesign the source when considering available control alternatives. For example, an existing pulverized-coal-fired electricity generating facility should not be required to consider integrated gasification coal combustion during the BART process, as BART focuses on technologies that can be retrofitted to the existing equipment.

In BACT and LAER determinations, any New Source Performance Standard (NSPS) or National Emissions Standard for Hazardous Air Pollutants (NESHAP) that exists for a source category is considered to the "floor" level of control, meaning that any proposed emission rate or control technology that is less stringent than the NSPS or NESHAP is not acceptable. Because BART involves retrofitting technology to existing emissions units that are not undergoing a major modification, it is possible, albeit unlikely, that an NSPS or NESHAP for a source category might not be the "floor" control for BART. Regardless, where a NSPS or NESHAP exists for a source category, EPA has directed States to include a level of control equivalent to the NSPS or NESHAP as one of the control options to be considered.

For some emissions units that are subject-to-BART controls, the actual control measures or devices that comprise BART may already be in place. In such instances, the BART analysis should consider

improvements to the existing controls or emissions limitations for those emissions units, and should not be limited to consideration of only the control devices themselves.

Finally, in some cases, if a State determines that a BART source already has controls in place which are the most stringent controls available, then it may not be necessary to comprehensively complete each following step of the BART analysis. EPA's guidance states that as long as the most stringent controls are made federally enforceable for the purposes of implementing BART for that source, a State may skip the remaining analyses, including the visibility analyses. Likewise, if a source commits to the most stringent level of BART control at the outset, then EPA's guidance suggests that there is no need to complete the remaining steps of the BART process.

Step 3: Eliminate All Technically Infeasible Control Options

This step is functionally equivalent to Step 2 in EPA's BART guidelines.

In this step, States are to evaluate the technical feasibility of the control options that were identified in Step 1. EPA's guidance generally considers a control option to be technically feasible if the controls have either: (1) been installed and operated successfully under similar conditions for the type of source under review, or (2) are available and could be applicable to the source under review. EPA's guidance states that a technology should be considered to be available if the source owner may obtain the control device through commercial channels, or the control is otherwise available within the common sense meaning of the term. Similarly, EPA considers an available control technology to be "applicable" if the control can be reasonably installed and operated on the source type that is under review. If a technology is considered to be both available and applicable, a State should consider the technology to be technically feasible.

If a technology is determined to be technically infeasible, then the State should provide documentation that demonstrates that the control is technically infeasible. EPA's guidance suggests that documentation that would be considered acceptable includes an explanation, based on physical, chemical, or engineering principles, as to why the control is technically infeasible and a discussion regarding why technical difficulties would preclude the successful use of the control option on the emissions unit under review.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

This step is functionally equivalent to Step 3 in EPA's BART guidelines. EPA's guidelines state that there are two key issues that must be addressed in this step:

(1) States should ensure that the degree of control is expressed using a metric that ensures an "apples to apples" comparison of emissions performance levels among the options; and

(2) States should give appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels.

When choosing an appropriate metric, EPA recommends selecting a metric that properly allows for the comparison of an inherently lower polluting process with a process that can only be addressed through the application of additional pollution controls. As a result, EPA has suggested that it is generally most effective to express emissions performance as an average steady state emissions level per unit of product produced or processed (i.e., pounds per million BTU, or pounds per ton of cement produced).

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

This step is functionally equivalent to Step 4 in EPA's BART guidelines. After identifying the available and technically feasible control technology options, States are expected to analyze the following when making a BART determination:

- Costs of Compliance
- Energy Impacts
- Non-air Quality Environmental Impacts
- Remaining Useful Life.

Each State is responsible for presenting an evaluation of each impact along with appropriate supporting information. States should discuss and, where possible, quantify both beneficial and adverse impacts. In general, the analysis should focus on the direct impact of the control alternatives.

Costs of Compliance

In the regional haze rules and its BART guidance document, EPA has stated that States have flexibility in how costs are calculated. EPA has expressed its position that the Control Cost Manual provides a good reference tool for cost calculations, but also provided some flexibility in this matter. If there are elements or sources that are not addressed by the Control Cost Manual, or if there are additional cost methods that were not considered in the BART guidance document, EPA determined that these methods could serve as useful supplemental information.

EPA's guidance also explains that States should consider both the average and incremental annualized costs of a control, as both provide information that is helpful when making a control determination. EPA took great care to explain, however, that these kinds of calculations can be misused, and that both numbers should be reviewed carefully.

In its guidance, EPA provided an example where a State may be faced with choosing between two available control options. The first control option (Option A) achieves a good level of control for a reasonable cost. The second control (Option B) achieves a slightly greater emissions reduction at a significantly increased cost. In this scenario, EPA explained that if only the average costs for Options A and B were considered, the overall costs associated with Options and B would be considered reasonable. EPA stated that while this may seem sufficient, a State should continue to look at the cost associated with a small increase in pollution control for a significantly greater price. EPA called this cost the "incremental cost" and explained that it can be determined through the following equation:

$$\frac{[CostOptionA - CostOptionB]}{[TotalAnnualEmissionsOptionA - TotalAnnualEmissionsOptionB]}$$

EPA explained that by considering this incremental cost, a State may determine that the incremental cost per unit of pollution removed that is associated with Option B may be greater than the benefit of requiring the control. As a result, even though the average cost associated with both controls might be reasonable, the incremental cost may make one option more desirable than the other.

As stated in the introduction to this Section, ADEQ sees the BART determination process as being substantially similar to the BACT processes. While BACT has components that address visibility, the principal cost decisions are generally charged only to the pollutant that is being reduced. Visibility

impacts, on the other hand, are quantified and considered as an environmental impact, rather than an economic impact. As a result, the most useful cost metric for comparing control technologies under BACT and LAER ends up being dollars-per-ton-of-pollutant-removed (dollars per ton).

Although the BART determination process is substantially similar to methodologies that are used to establish BACT and LAER, the entire purpose behind BART is to support Congress' goal of reducing visibility impairment in Class I areas. In addition, BART differs from BACT and LAER in that the environmental impacts of the selected control can only address issues that are not related to air quality. As a result, ADEQ has determined that in addition to a dollar per ton metric, the BART determination process should also provide lesser consideration to a dollar-per-deciview-improvement metric.

Energy Impacts

In its guidance, EPA suggests that States should also examine the energy requirements of the control technology to determine whether the use of that technology will result in energy penalties or benefits. For instance, if a control technology is required to remediate an emissions stream that is rich in volatile organic compounds, a facility might benefit by using this combustion process to reduce energy costs. Conversely, a facility that installs a wet scrubber may suffer an energy penalty due to the increased power necessary to overcome the increased air flow resistance through the scrubber.

It should be noted that unless there is ample justification, only direct energy benefits or penalties should be considered in this analysis. Indirect energy costs should not be considered unless there is something unusual or significant enough to warrant further consideration. It is appropriate for energy impact analyses to consider the local availability (or scarcity) of specific fuels, as well as the potential differences between locally or regionally available coals.

It is also important to note that adverse energy impacts are not enough, in and of themselves, to disqualify a technology from consideration. If such penalties or benefits exist, however, it is appropriate to document these and include them in this section so that the results of all of the analyses required in this Step can be considered as a whole.

Non-Air Quality Environmental Impacts

This portion of the analysis is to focus on impacts to environmental media other than air quality. Examples of common environmental impacts include hazardous waste generation, hazardous waste discharges, and discharges of polluted water from a control device.

All non-air quality environmental impacts should be reviewed using site-specific circumstances when possible. Should a State propose to adopt the most stringent BART option then it is not necessary to perform this analysis of environmental impacts for the entire list of technologies that were ranked in the previous Step. In general, the analysis only needs to address those control alternatives with any significant or unusual environmental impacts that have the potential to affect the selection of a control alternative, or to eliminate a more stringent control technology.

In general, States should identify and document any direct or indirect, significant or unusual environmental impacts that are associated with a specific control alternative. For example, a wet scrubber will release effluent that has the potential to affect water or land use. Other examples might include disposal of spent catalyst, or contaminated carbon from a filtration device. Such types of environmental impacts could become even more important with the potential for sensitive site-specific receptors, or

when comparing control technologies that have similar or marginal air quality improvements but result in substantial environmental impacts.

Remaining Useful Life

The remaining useful life of a source should be considered in the evaluation of the different controls, as it has the potential to impact the overall cost analysis. If the remaining useful life represents a relatively short period of time, then the annualized costs associated with the application of a control technology will increase significantly. EPA explained in its guidelines that the remaining useful life is the difference between the date that controls will be put into place and the date that the facility permanently stops operations.

If the remaining useful life of the facility affects the BART determination, then this date should be placed into a federally or State-enforceable restriction that prevent further operation of that facility after that date. If a source wants to have the flexibility to continue operating after the date upon which operations are expected to cease, then the BART analysis may account for the option, but it must maintain consistency with the statutory requirement to install BART within 5 years. In addition, if the remaining useful life changes the BART decision as a result of adverse cost impacts, then the BART determination should identify the more stringent level of control that would be required as BART if there was no assumption that reduced the remaining useful life of the facility.

Step 6: Evaluate Visibility Impacts

This step is functionally equivalent to Step 5 in EPA's BART guidelines.

Once a State has determined that its source or sources are subject-to-BART, a visibility improvement determination for the source(s) must be conducted as part of the BART determination. States have the flexibility in setting absolute thresholds, target levels of improvement, or de minimis levels for visibility improvement since the deciview improvement must be weighed among the five factors. States are also free to determine the weight and significance to be assigned to each factor. For example, a 0.3 dv improvement may merit a stronger weighting in one case versus another. As a result, EPA does not recommend a "bright line" analysis to be used across all facilities that are subject-to-BART.

EPA's guidelines recommend the use of CALPUFF or another appropriate dispersion model to determine the visibility improvement expected at a Class I area from the potential BART control technology applied to the source. Modeling should be conducted for NO_X emissions, direct PM emissions ($PM_{2.5}$ or PM_{10}), and SO_2 emissions. If the source is making the visibility determination, States should review and approve or disapprove the source's analysis before making the expected improvement determination.

Arizona instituted a portion of this process by asking sources for a modeling protocol for each of the BART analyses that were submitted. Each source was then asked to run its model at pre-control and post-control emission rates using the accepted methodology in the protocol. Sources used the 24-hour average actual emissions rate from the highest emitting day of the meteorological period modeled, and calculated the model results for each receptor as the change in deciviews compared against natural visibility conditions. Post-control emissions rates were then calculated as a percentage of pre-control emissions rates.

Step 7: Select BART

This step is in addition to the five steps that are recommended in EPA's BART guidelines.

States have discretion to determine the order in which they should evaluate control options for BART. EPA's guidance states that whatever the order, States should always address the five factors. In addition, States should provide a justification for whatever control option is selected. ADEQ has determined that the contents of the TSD will provide the necessary explanations.

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IX. CATALYST PAPER (SNOWFLAKE) INC. (CPSI) FORMERLY ABITIBI CONSOLIDATED) BART ANALYSIS AND DETERMINATION

A. Process Description

Abitibi Consolidated was purchased by CPSI in April of 2008. CPSI operates a recycled paper mill near Snowflake, Arizona, which produces newsprint and newsprint-like grades at a capacity of approximately 1,460 tons per day. A Powerhouse consisting of 3 boilers provides steam and electricity for use at the mill. Power Boiler #2 is rated at 1,132 million British thermal units (MMBtu) per hour and is the primary boiler. Power Boilers #1 and #3 are standby units and are rated at 523 MMBtu per hour and 337 MMBtu per hour respectively.

B. Description of Emissions Units Subject to Best Available Retrofit Technology (BART)

Power Boiler #2 is a coal-fired boiler installed in 1975. It emits more than 250 tons per year (tpy) of nitrogen oxides (NO_X) and sulfur dioxide (SO_2). CALPUFF modeling performed by CPSI demonstrated that the boiler has a visibility extinction of 0.739 deciviews on the Sierra Ancha Wilderness Area and 0.523 deciviews on the Superstition Wilderness Area. Therefore, the unit contributes to the impairment of visibility at a Class I area and is subject-to-BART for NO_X and SO_2.

C. NO_X BART Analysis and Determination

Step 1: Identify the Existing Control Technologies in Use at the Source

CPSI currently does not operate any NO_x control technology on Power Boiler #2 although there is a permit limit of 0.7 lb/MMBtu. There is an existing over fire air system (OFA) that has never been operated.

Step 2: Identify All Available Retrofit Control Options

CPSI has identified seven control options:

- Operate the existing OFA
- Install Low NO_X Burners (LNB)
- Install LNB with new OFA
- Install LNB, new OFA, and a selective non-catalytic reduction system (SNCR)
- Install a Rotating Over Fire Air (ROFA) system
- Install a ROFA with SNCR
- Install LNB, new OFA, and a selective catalytic reduction system (SCR)

Operate the existing OFA. The existing OFA consists of a 300 horsepower fan which reduces NO_x emissions by diverting a portion of the combustion air to the lower furnace.

Install LNB. LNB stage the combustion process to provide a fuel-rich condition initially so that less oxygen is available to combine with nitrogen and form NO_X.

Install LNB with new OFA.

Install LNB, new OFA, and SNCR. SNCR works by injecting ammonia or urea into the furnace to reduce NO_X to nitrogen and water. SNCR is more effective when combined with LNB and OFA.

Install a Rotating Opposed Fire Air system (ROFA). ROFA works by creating a turbulent flow of air throughout the volume of the furnace which lowers combustion temperature and reduces the formation of NO_X.

Install a ROFA with SNCR.

Install LNB, new OFA, and SCR. SCR operates much like SNCR but with the addition of a catalyst. The catalyst provides a surface on which the reduction reaction takes place.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the control options identified above are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

According to the analysis performed by Catalyst Paper, the technically feasible control options were identified as being able to achieve the following emissions rates (Table 9.1):

Table 9.1 – Control Effectiveness of Control Options

Control Option	Achievable Emissions Rate (lb/MMBtu)
OFA	0.525
LNB	0.370
ROFA	0.348
ROFA with SNCR	0.291
LNB with new OFA	0.265
LNB, OFA, and SNCR	0.194
LNB,OFA, and SCR	0.070

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

Cost of Compliance

During the course of Catalyst Paper's review of the technically feasible control options, the company identified the expected amount of emissions reduced by the application of each control option, as well as the annualized cost, and the average cost effectiveness of the controls. That information is summarized in Table 9.2 below.

Table 9.2 – Cost of Compliance of Control Options			
Control Option	**Expected Emissions Reduction (tpy)**	**Annualized Cost**	**Average Cost Effectiveness ($/ton NO_x)**
OFA	868	$3,221,359[2]	$3,711
LNB	1,636	$3,400,185	$2,078
ROFA	1,745	$4,262,553	$2,443
ROFA with SNCR	2,028	$4,903,534	$2,418
LNB with new OFA	2,157	$3,509,992	$1,627
LNB, OFA, and SNCR	2,509	$3,968,779	$1,582
LNB,OFA, and SCR	3,124	$7,181,536	$2,299

1. This analysis assumes the facility is current emitting NO_x at the permit limit of 0.7 lb/MMBtu. That is the rate at which CPSI modeled visibility impacts and therefore must be held constant for any analysis based on emission rates.
2. There is a large annualized cost to this existing equipment because it has been assumed that its operation would make the fly ash from the boiler unsellable.

From Table 9.2, it can be seen that ROFA and ROFA with SNCR are inferior options because there is an option (LNB with new OFA) that provides greater annual reduction at a lower annualized cost. ADEQ has eliminated those control options from consideration and the incremental cost effectiveness associated with the remaining control options is as follows (Table 9.3):

Table 9.3 – Incremental Cost Effectiveness of Remaining Control Options		
Control Option	**Cost Effectiveness ($/ton NO_X)**	**Incremental Cost Effectiveness ($/ additional ton NO_X)**
OFA	$3,711	--
LNB	$2,078	$233
LNB with new OFA	$1,627	$211
LNB, OFA, and SNCR	$1,582	$1,303
LNB,OFA, and SCR	$2,299	$5,224

Energy Impacts

According to the analysis provided by CPSI, there are adverse energy impacts that require consideration for several of the technically feasible control options. Specifically, CPSI reported that the OFA would require 224 kW of power, the SNCR would require 10 kW, and the SCR would require 377 kW. ADEQ notes that the LNB would require no additional power.

Non Air-Quality Environmental Impacts

According to CPSI's analysis, non-air quality impacts may result due to the application of several technically feasible control technologies. Specifically, CPSI stated that due to the potential increase in

the amount of unburnt carbon, the installation of LNB and OFA may have the potential of rendering the fly ash unsellable. If the fly ash were rendered unsellable, the fly ash would increase the amount of solid waste generated at the facility, ultimately increasing the amount sent to the landfill.

In addition to the LNB and OFA technologies, SCR and SNCR have the potential to impact the salability of the fly ash. As noted above, both technologies rely on the injection of ammonia to reduce the formation of NO_X. Most SCR and SNCR vendors recommend that the operator inject more than the stoichiometric amount of ammonia to drive NO_X formation to a minimum. This practice results in emissions of ammonia (called ammonia slip). Since the ammonia has an affinity for the fly ash, its presence in the exhaust stream could result the spoiling of the fly ash, leading to increased solid waste from the facility.

Remaining Useful Life

None of the documentation submitted by CPSI has indicated that the facility will be shut down in the near future. For the purposes of its analyses, CPSI assumed a typical equipment life of 15 years for calculating the annualized cost of control options. As a result, ADEQ has determined that the remaining useful life of the mill has no effect on this BART analysis.

Step 6: Evaluate Visibility Impacts

As part of its analysis of potential BART options, CPSI estimated the total visibility improvement that is projected to occur should one of the technically-feasible and cost-effective control options be applied. Based upon that information, ADEQ was also able to calculate the average cost effectiveness in terms of dollars per deciview of visibility improvement. CPSI's results are summarized in Table 9.4 below.

Table 9.4 – Visibility Impacts of Remaining Control Options

Control Option	Deciview Improvement*	Cost Effectiveness* ($/Deciview)
OFA	0.076	$42.4 million
LNB	0.164	$20.7 million
LNB with new OFA	0.207	$17.0 million
LNB, OFA, and SNCR	0.252	$15.7 million
LNB,OFA, and SCR	0.309	$23.2 million

*Based on visibility effects at most impacted Class I area – Sierra Ancha WA

Step 7: Select BART

Based upon its review of CPSI's analysis, and in particular the marginal visibility impact from the current facility operations and the magnitude of the dollar per deciview costs in Table 9.4 , ADEQ has determined that BART for control of NO_X from Power Boiler #2 is the current emission limit of 0.7 lb/MMBtu on a 30-day rolling average basis.

D. SO_X BART Analysis and Determination

Step 1: Identify the Existing Control Technologies in Use at the Source

Power Boiler #2 has a SO_2 permit limit of 0.8 lb/MMBtu and is controlled with a wet sodium flue gas desulfurization system tray tower scrubber. The scrubber captures 68% of the flue gas and has a control efficiency of 94%. The overall control efficiency of the system is 63.9%.

Step 2: Identify All Available Retrofit Control Options

CPSI has identified two control options as potentially being BART:

- Upgrade the existing scrubber
- Add a second scrubber

Upgrade the existing scrubber. When CPSI conducted this analysis, the scrubber on Power Boiler #2 has a control efficiency of 94%. The scrubber control efficiency could be increased to 98% by performing the following upgrades:

- Wash the integral mist eliminators with demineralized water.
- Improve bypass damper control.
- Improve scrubber solution pH control
- Blowdown spent scrubber liquor based on density control rather than the current manual blowdown procedure.
- Add sidewall casing baffles below the recycle spray nozzles and mist eliminators to prevent gas leakage.
- Replace worn and plugged spray nozzles.
- Clean scrubber equipment and piping to remove plugging and buildup.

Increasing the scrubber's control efficiency from 94 to 98% would result in increasing the scrubber's overall control efficiency from 63.9% to 66.6%.

These efficiencies were calculated in 2007 and were based on the historical combustion of McKinley Mine coal with an average sulfur content of 1.1 lb/MMBtu. In 2008, CPSI was forced to switch to Lee Ranch Mine coal due to the closure of the McKinley Mine. The coal now available to CPSI has an average sulfur content of 2.3 lb/MMBtu and the facility has been forced to complete much of the upgraded scrubber project in order to maintain compliance with the 0.8 lb/MMBtu emission limit in its operating permit. As it now represents baseline control, it is no longer appropriate to consider upgrading the scrubber to be an additional control option.

Add a second scrubber. A second scrubber could be added in order to capture 100% of the flue gas at an efficiency of 98%. This would increase the overall control efficiency from 63.9% to 98% control.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that both control options identified above are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies.

According to the analysis performed by CPSI, the technologically feasible controls are capable of achieving the following emissions rates (Table 9.5):

Table 9.5 – Control Effectiveness of Control Options	
Control Option	**Achievable Emissions Rate (lb/MMBtu)**
Upgrade Current Scrubber / Baseline Control	0.80
Add Second Scrubber	0.044

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

Cost of Compliance

During the course of CPSI's review of the technically feasible control options, the company identified the expected amount of emissions reduced by the application of each control option, as well as the annualized cost and the average cost effectiveness. That information is summarized in Table 9.6 below.

Table 9.6 – Cost of Compliance of Control Options			
Control Option	**Expected Emissions Reduction (tpy)**	**Annualized Cost**	**Average Cost Effectiveness ($/ton SO_2)**
Upgrade Current Scrubber / Baseline Control	0	0	N/A
Add second scrubber	3,743	$4,769,365	$1,274

1. This analysis assumes the facility is current emitting SO_2 at the permit limit of 0.8 lb/MMBtu. That is the rate at which CPSI modeled visibility impacts and therefore must be held constant for any analysis based on emission rates.

Energy Impacts

It is expected that the addition of a second scrubber would increase the amount of energy necessary to overcome the increased pressure drop that would result from the gas moving through the scrubber. CPSI, however, has stated that these energy impacts are expected to be minimal.

Non Air-Quality Environmental Impacts

CPSI has stated that the addition of a second scrubber will result in the generation of an additional 8,000 tpy of solid scrubber waste and the additional use of 38 million gallons of water per year.

Remaining Useful Life

None of the documentation submitted by CPSI has indicated that the facility will be shut down in the near future. For the purposes of its analyses, CPSI assumed a typical equipment life of 15 years for calculating the annualized cost of control options. As a result, ADEQ has determined that the remaining useful life of the mill has no effect on this BART analysis.

Step 6: Evaluate Visibility Impacts

As part of its analysis of potential BART option, CPSI estimated the total visibility improvement that is projected to occur should one of the technically-feasible and cost-effective control options be applied. Based upon that information, ADEQ was also able to calculate the average cost effectiveness in terms of dollars per deciview of visibility improvement. CPSI's results are summarized in Table 9.7 below.

Table 9.7 – Visibility Impacts of Control Options

Control Option	Deciview Improvement*	Cost Effectiveness* ($/Deciview)
Add 2nd Scrubber	0.20	$23.8 million

1. Based on visibility effects at most impacted Class I area – Sierra Ancha WA

Step 7: Select BART

Based upon its review of CPSI's analysis, and the all of the considerations listed above, ADEQ has determined that BART for control of SO_2 from Power Boiler #2 is the current upgraded scrubber, as defined in Step #2, with an emission limit of 0.80 lb/MMBtu on a 30-day rolling average basis.

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X. ARIZONA ELECTRIC POWER COOPERATIVE – APACHE GENERATING STATION BART ANALYSIS AND DETERMINATION

A. Process Description

The Apache Generating Station consists of seven electric generating units (two coal/natural gas-fired steam electric units, a natural gas/fuel oil-fired steam electric, combined cycle unit, and four natural gas/fuel oil-fired turbines) with a total generating capacity of 560 megawatts (MW). The power plant is located approximately 3 miles southeast of the town of Cochise in the Wilcox Basin in Cochise County, Arizona. Apache Steam Unit 1 is a wall-fired steam electric generating unit that can burn natural gas and numbers 2 through 6 fuel oils. The unit is permitted to produce up to a maximum capacity of 85 MW of electricity. Steam Units 2 and 3 are 195 MW natural gas and coal-fired steam electric generating units equipped with dry-bottom turbo-fired coal boilers manufactured by Riley Stoker.

The remaining four units at the Apache Generating Station are simple cycle gas turbines. Steam Unit 1 and Gas Turbine 1 can be operated separately or in a combined cycle configuration.

B. Description of Emissions Units Subject to Best Available Retrofit Technology (BART)

Apache Generating Station Units 1, 2, 3 are potentially subject-to-BART because:

1. These units belong to one of the 26 categorical sources;
2. These units were in existence on August 7, 1977;
3. Emissions of visibility impairing pollutants from all BART-eligible emissions units - nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM) – are greater than 250 tons per year for each pollutant.

The simple cycle gas turbines at the Apache Generating Station are not BART-eligible, and therefore were not considered as part of this analysis.

C. Impact on Visibility

CALPUFF modeling was performed at nine Class I areas that are located within 300 kilometers of the Apache Generating Station. Table 10.1 provides the baseline maximum impact on visibility in deciview (98th percentile, 3-year average).

Table 10.1 – Modeled Baseline Impact on Visibility

Affected Class I Area	Unit 1 (dv)	Unit 2 (dv)	Unit 3 (dv)
Chiricahua NM	2.75	2.47	2.37
Galiuro Wilderness	1.58	1.92	1.75
Saguaro NP	1.98	1.69	1.55
Gila Wilderness	0.45	0.76	0.69
Superstition	0.98	1.49	1.35

Table 10.1 – Modeled Baseline Impact on Visibility			
Affected Class I Area	**Unit 1 (dv)**	**Unit 2 (dv)**	**Unit 3 (dv)**
Wilderness			
Mt. Baldy Wilderness	0.32	0.45	0.41
Sierra Ancha Wilderness	0.62	0.89	0.80
Mazatzal Wilderness	0.81	0.85	0.76
Pine Mountain Wilderness	0.68	0.68	0.61

The impact of Units 1, 2, and 3 on the visibility in at least one Class I area is more than 0.5 Deciviews. Therefore, per 40 CFR Part 51, Appendix Y, these units cause or contribute to visibility impairment and are subject-to-BART.

D. Steam Unit 1 (ST1)

D.1 NO_X BART Analysis

NO_X formation in fossil fuel-fired boilers is a complex process that is dependent on a number of variables, including operating conditions, equipment design, and fuel characteristics. A NO_X BART analysis was completed for the cases when ST1 burns 100 percent pipeline natural Gas (PNG), 100 percent No. 6 fuel oil (this was done as a test case, as AEPCO has never combusted No. 6 fuel oil in the unit), and 100 percent No. 2 fuel oil.

Formation of NO_X

During combustion, NO_X forms in three different ways: thermal NO_X, fuel NO_X, and prompt NO_X. When combusting PNG, the most dominant source of NO_X is from thermal NO_X, which results from high-temperature fixation of atmospheric nitrogen in the combustion air. Because PNG generally contains small quantities of nitrogen, the overall contribution from fuel NO_X is small, whereas a significant amount of fuel NO_X can be generated from fuel oil combustion. A very small amount of NO_X is called "prompt" NO_X. Prompt NO_X results from an interaction of hydrocarbon radicals, nitrogen, and oxygen.

Step 1: Identify the Existing Control Technologies in Use at the Source

There is no NO_X emissions control equipment installed on ST1.

Step 2: Identify All Available Retrofit Control Options

The second step of the BART process is to evaluate NO_X control technologies with practical potential for application to ST1, including those control technologies identified as BACT or LAER by permitting

agencies across the United States. ST1 NO_X emissions are currently controlled through the use of good combustion practices.

The following potential NO_X control technology options were considered:

- New LNBs with OFA
- Flue Gas Recirculation (FGR)
- Rotating Opposed Fire Air (ROFA)
- LNBs with selective non-catalytic reduction system (SNCR and Rotamix)
- LNBs with selective catalytic reduction system (SCR)
- Neural Net Controls

New LNBs with OFA System. The mechanism used to lower NO_X with LNBs is to stage the combustion process and provide a fuel-rich condition in the initial stages of combustion; this is so oxygen needed for combustion is not diverted to combine with nitrogen resulting in the formation of NO_X. Fuel-rich conditions favor the conversion of fuel nitrogen to nitrogen dioxide (N2) instead of NO_X. Additional air (or OFA) is then introduced downstream in a lower temperature zone to burn out the char, or remaining uncombusted fuel. Both LNBs and OFA are considered to be a capital cost, combustion technology retrofit that may require water wall tube replacement.

FGR. FGR generally extracts flue gas from downstream of the economizer or air heater and is mixed into the combustion air duct. This recirculation can be achieved with a new FGR fan or by using the existing forced-draft fan to inject the flue gas into the combustion air (induced flue gas recirculation [IFGR]). Flue gas recirculation adds oxygen-lean, heat-absorbing mass to the combustion air, thus lowering the combustion temperature and reducing thermal NOx emissions.

ROFA. Mobotec markets ROFA as an improved, second-generation OFA system. Mobotec states that "the flue gas volume of the furnace is set in rotation by asymmetrically placed air nozzles. Rotation is reported to prevent laminar flow, so that the entire volume of the furnace can be used more effectively for the combustion process. In addition, the swirling action reduces the maximum temperature of the flames and increases heat absorption. The combustion air is also mixed more effectively."

A typical ROFA installation will have a booster fan(s) to supply the high velocity air to the ROFA boxes. Mobotec would propose one 700 horsepower fan for ST1. Mobotec's budgetary proposals included expected NOx emission rates for PNG and No. 2 and No. 6 fuel oils, and are presented in Table 2. While a typical installation does not require modifying an installed LNB system, and the existing OFA ports are not used, results of computational fluid dynamics modeling will determine the quantity and location of new ROFA ports. Although not specifically identified, Mobotec generally includes bent tube assemblies for OFA port installation if required. Mobotec does not provide installation services, because they believe that the owner can more cost-effectively contract for these services. However, they do provide one onsite construction supervisor during installation and startup.

SNCR. SNCR is generally used to achieve modest NOx reductions on smaller units. With SNCR, an amine-based reagent such as ammonia—or more commonly urea—is injected into the furnace within a temperature range of 1,600 degrees Fahrenheit (°F) to 2,100°F, where it reduces NO_X to nitrogen and water. NO_X reductions of up to 60 percent have been achieved, although 20 to 40 percent is a more realistic expectation for most applications. Reagent utilization, which is a measure of the efficiency with which the reagent reduces NO_X, can range from 20 to 60 percent, depending on the amount of reduction, unit size, operating conditions, and allowable ammonia slip. With low-reagent utilization, low temperatures, or inadequate mixing, ammonia slip occurs, allowing unreacted ammonia to create

problems downstream. Typical problems include rendering the fly ash unsellable, reacting with sulfur to foul heat exchange surfaces, or creating a visible stack plume. Reagent utilization can have a significant impact on economics in that each incrementally higher level of NO_X reduction generally results in lower reagent utilization and higher operating cost.

Reductions from higher baseline concentrations (inlet NO_X) are lower in cost per ton, but result in higher operating costs, due to greater reagent consumption. Budgetary proposals were received from Mobotec for their Rotamix system, and previous Fuel Tech proposal information for other projects was used.

SCR. SCR works on the same chemical principle as SNCR but instead uses a catalyst to promote the chemical reaction. Ammonia is injected into the flue-gas stream, where it reduces NO_X to nitrogen and water. Unlike the high temperatures required for SNCR, in SCR the reaction takes place on the surface of a vanadium/titanium-based catalyst at a temperature range between 580°F and 750° F. Due to the catalyst, the SCR process is more efficient than SNCR and results in lower NO_X emissions.

Neural Net Controls. Information regarding neural net controls was received from NeuCo, Inc. While NeuCo offers several neural net products, CombustionOpt and SootOpt provide the potential for NOx reduction. NeuCo stated that these products can be used on most control systems and can be effective even in conjunction with other NO_X reduction technologies. NeuCo predicts that CombustionOpt can reduce NO_X by 15 percent, and SootOpt can provide an additional 5 to 10 percent. Because NeuCo does not offer guarantees on this projected emission reduction, a nominal reduction of 15 percent was assumed for evaluation purposes.

Because NeuCo does not guarantee NO_X reduction, ADEQ has determined that the estimated emission reduction levels provided cannot be considered as reliable projections. Therefore, neural net should be considered as a supplementary or "polishing" technology, but not on a "stand-alone" basis.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the identified control technologies are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

Table 10.2 lists the various control technologies and estimated emissions rates.

Table 10.2 – NO_X Control Technology Emission Rate Ranking

Technology	Source of Estimated Emissions	Estimated Emission Rate[4] (PNG)	Estimated Emission Rate (No. 6 Fuel Oil)[d]	Estimated Emission Rate (No. 2 Fuel Oil)[d]
LNB with FGR[e]	Coen	0.056	0.15	0.06
ROFA[b]	Mobotec	0.08	0.16	0.08
ROFA with Rotamix[b]	Mobotec	0.06	0.11	0.06
LNB with FGR, SNCR	Coen & Fuel Tech	0.06[c]	0.11[c]	0.05[c]
SCR[a]	CH2M Hill	0.07	0.07	0.07

[a] SCR estimated NO_X emissions rate is the same for all scenarios. Operating cost would be affected by inlet NO_X levels.
[b] Calculated from Mobotec proposal information fuel baselines (47 percent reduction for ROFA and additional 30 percent for Rotamix)
[c] From Previous Fuel Tech Proposal at 25 percent reduction
[d] Results are in lb/MMBtu
[e] From Coen Proposal

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts

Installation of LNBs is not expected to significantly impact the boiler efficiency or forced-draft fan power usage. Therefore, these technologies will not have energy impacts. The Mobotec ROFA system requires installation and operation of one 700 horsepower ROFA fan (522 kilowatts [kW] total). An estimated auxiliary power requirement for an SNCR system for an 85-MW (with the 10-MW combustion turbine included) unit is estimated at 85 kW. The same estimate was used for Rotamix. SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase.

Environmental Impacts

Environmental impacts associated with SCR and SNCR involve the hazards associated with the storage of ammonia, especially if anhydrous ammonia is used, and the transportation of the ammonia to the power plant site.

Economic Impacts

Costs and emissions estimates for the LNBs, SNCR, and SCR were obtained from equipment vendors. Costs for the ROFA and Rotamix systems were obtained from Mobotec. A comparison of the technologies on the basis of costs, design control efficiencies, and tons of NO_X removed is summarized in Table 10.3. The capital costs shown in Table 3 are applicable for all of the fuels under consideration, and No. 6 fuel oil was used as the basis to determine worst-case emission levels. For example, if LNBs are installed for PNG, the burner costs include the capability to burn both PNG and No. 2 and 6 fuel oils (with only minor equipment modification, atomization changes, and burner control revisions). Similarly, the cost information for any of the NO_X reduction technologies listed in Table 3 will apply for the fuel alternatives under consideration. Costs for LNBs are presented with FGR because this scenario is representative of current operation of ST1 when it is operated in combined cycle with Gas Turbine #1. Costs for LNBs without FGR would be lower. The complete Economic Analysis is contained in Appendix A of the AEPCO BART submittal.

Table 10.3: NO_x Control Cost Comparison					
Factor	**ROFA[c]**	**LNB with FGR**	**LNB with FGR & SNCR[b]**	**ROFA with Rotamix**	**LNB with SCR[a]**
Total installed capital cost (Million $)	$2.700	$1.184	$4.584	$4.457	$25.50
Total installed capital cost + additional owner costs (Million $)	$4.725	$2.072	$5.730	$7.800	$31.88
Total first year fixed and variable O&M costs (Million $)	$0.145	$0.204	$0.116	$0.195	$0.346
Total first year annualized cost	$0.939	$0.552	$1.079	$1.506	$5.705
Power consumption (MW)	0.52	0.85	0.09	0.52	0.43
Annual power usage (Million kW-hr/yr)	1.9	3.1	0.3	1.9	1.5
NOx design control efficiency	46.8%	50.2%	63.5%	63.5%	76.7%
Tons NOx removed per year	278	297	376	376	455
First year average control cost ($/ton removed)	$3,382	$1,856	$2,870	$4,004	$12,542
Incremental control cost ($/ton removed)	-$19,659	$1,856	$1,425	---[d]	$53,311

[a] Based on $300 per kW SCR factored estimate for 85 megawatts
[b] Based on $40 per kW SNCR factored estimate for 85 megawatts
[c] ROFA has a negative incremental control cost because when compared with LNB with FGR the technology costs more and removes less tons of NO_x
[d] The incremental control cost for ROFA with Rotamix when compared with LNB with FGR and SNCR results in a non number as the two technologies have the same NO_x removal in tons per year

Step 6: Evaluate Visibility Impacts

Table 10.4 below shows the total deciview reduction for the most impacted Class I area. For ST1, the most impacted Class I area is the Chiricahua Wilderness Area and National Monument.

Table 10.4 – Control Technologies and Respective Deciview Reduction			
Control	**Deciview Reduction**	**Total Annualized Cost (Million $)**	**Cost per deciview reduced (Million $/deciview reduced)**
LNB with FGR	0.194	0.552	2.845
ROFA	0.256	0.939	3.668
ROFA with Rotamix	0.240	1.506	6.274

Table 10.4 – Control Technologies and Respective Deciview Reduction			
Control	**Deciview Reduction**	**Total Annualized Cost (Million $)**	**Cost per deciview reduced (Million $/deciview reduced)**
LNB with FGR and SNCR	0.240	1.079	4.497
SCR	0.409	5.705	13.948

Step 7: BART Determination

After reviewing the company's BART analysis, and based upon the information above ADEQ has determined that, for Unit 1, BART for NO_X is the installation of LNB with FGR (from GT1) with a NO_X emissions limit of 0.056 lb/MMBtu when burning pipeline quality natural gas (PNG). Fuel oil will not longer be an authorized fuel for Unit 1. the limit would apply on a 30-day rolling average basis.

D.2 PM_{10} BART Analysis

The PM_{10} BART analysis is only completed for the case when ST1 burns 100 percent No. 6 fuel oil. This was done for comparison only, as AEPCO has never combusted No. 6 fuel oil in the unit).

Step 1: Identify the Existing Control Technologies in Use at the Source

There is no emissions control equipment installed on ST1.

Step 2: Identify All Available Retrofit Control Options

The following retrofit control technologies have been identified for PM_{10} control on ST1:

- Use of low-sulfur fuel oil (No. 2 fuel oil)
- Switch to PNG
- New LNBs/particulate matter burner
- Dry electrostatic precipitator (ESP)
- Wet ESP
- Fabric filter

Low Sulfur Distillate Oil. Particulate matter emissions would be reduced with the switching of fuel oil grades from No. 6 to No. 2. PM_{10} emissions while burning No. 2 fuel oil are estimated at 0.0143 lb/MMBtu.

Switch to PNG. Expected PM_{10} emissions when burning PNG are estimated at 0.0075 lb/MMBtu.

New LNBs/Particulate Matter Burner. With the Coen LNB, particulate matter emissions are also reduced. From the budgetary information received from Coen, particulate matter emissions are estimated at less than 0.03 lb/MMBtu and 0.0015 lb/MMBtu while burning No. 6 fuel oil (with LNB and IFGR), and No. 2 fuel oil (LNB), respectively.

Dry ESP. A dry ESP operates by first placing a charge on the particulates though a series of electrodes, and then capturing the charged particulates on collection plates. While an ESP can be designed for high-particulate removal, operation is susceptible to particle resistivity, which denotes a collected particle's ability to ultimately discharge to the collection plate. Low-resistivity particles can be easily charged but may quickly lose their charge at the collection plate and tend to be re-entrained into the flue gas stream. Higher resistivity particles may form a "back corona," which is caused by a layer of non-conductive particles being formed on the collection plate. Back corona may prevent other charged gas stream particles from migrating to the collection plate. Particle resistivity is also influenced by flue gas temperature. ESP sizing is in large part determined by particulate size, with larger ESP size required when smaller particulates are expected. In addition, the particulates from an oil-fired unit tend to be small and sticky, and if a Spray Dryer Absorber is used for SO_2 reduction, there will be a greatly increased inlet particulate loading to the ESP. Because of the uncertainty in chemical and physical characteristics of the oil-fired particulate, ADEQ determined that a dry ESP is not a good technological match for ST1.

Wet ESP. While wet ESP operation is similar to the dry ESP through the charging and collection of flue gas particulates, the wet technology has significant advantages. The wet ESP is not sensitive to particulate resistivity and can accommodate changes in particulate loading more easily than a dry ESP. Collection plates can be created from metal or fabric, and the collected particulate is washed off the plates with water.

Wet ESPs have successfully been demonstrated on similar oil particulate or chemical mist applications. However, flue gas leaving the wet ESP will be saturated and may result in a visual steam plume exiting the stack. The wet ESP will use water to collect and remove the particulates, and will produce a wastewater byproduct. While the wet ESP PM_{10} emission level is estimated to be similar to a fabric filter without SDA operation, increased particulate loading from an SDA may not allow a wet ESP to meet required collection efficiency. Therefore, ADEQ has determined that a wet ESP is not a technically acceptable alternative when matched with an SDA.

Fabric Filter. Fabric filter technology achieves particulate reduction through the filtration of the flue gas through filter bags. The collected particles are periodically removed from the bag through a pulse jet or reverse flow mechanism. A pulse jet filtration system would likely be selected for installation on ST1, because this fabric filter technology results in lower capital cost and a smaller required footprint.

Because of the somewhat sticky particles produced during oil firing, using an appropriate fabric or coating bags with a suitable pre-coat material is imperative. If fabric bags become "blinded" by allowing hard-to-remove particulates to become embedded in the fabric structure, total bag replacement may be necessary. Blinded bags will continue to provide excellent filtration efficiencies; however, the pressure drop across the fabric may exceed system draft capability.

ADEQ has determined that while a fabric filter is not an acceptable alternative for particulate matter/PM_{10} emissions control for an oil-fired unit without using a coating material for the bags, it is anticipated to function satisfactorily with a pre-coat and the increased particulate loading from the SDA operation.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the identified control technologies are technically feasible, with the exception of wet and dry ESPs, for the reasons discussed in Step 1 above.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

ST1 particulate matter emissions are currently estimated at 0.0737 lb/MMBtu while burning No. 6 fuel oil. The BART PM_{10} analysis will be completed only for the case of firing 100 percent No. 6 fuel oil. The PM_{10} control technology emission rates are summarized in Table 10.5. No capital costs are associated with switching to PNG.

Table 10.5 – PM_{10} Control Technology Emission Rates

Control Technology	Expected PM_{10} Emission Rate (lb/MMBtu)
Current Baseline	0.0737
Fabric Filter	0.015
New LNB[a]	0.0015
Switch to PNG	0.0075

[a] When burning No. 2 fuel oil

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts

No additional energy impact is expected from PM_{10} reduction as a result of a new LNBs/particulate matter burner retrofit or burning of low-sulfur fuel oil. A fabric filter and ductwork will add an estimated 6 to 8 inches of water pressure drop to the system and additional electrical load requirements.

Environmental Impacts

There are no negative environmental impacts from the usage of new LNBs/particulate matter burners, switching to low-sulfur diesel fuel, or using a fabric filter.

Economic Impacts

A summary of the costs and particulate matter removed for the alternatives is recorded in Table 6.

Table 10.6 – Particulate Matter Control Cost Comparison*

Factor	Fabric Filter	Switch to PNG	Switch to Low-Sulfur Fuel
Total installed capital costs	$20,000,000[a]	$0	$1,000,000[b]
Total first year fixed and variable O&M costs	$253,592	--	--
Total first year annualized cost	$3,615,938	--	--
Power consumption (MW)	0.40	--	--

Table 10.6 – Particulate Matter Control Cost Comparison*			
Factor	**Fabric Filter**	**Switch to PNG**	**Switch to Low-Sulfur Fuel**
Annual power usage (Million kW-hr/year)	1.4	--	--
Particulate matter design control efficiency	79.6%	--	--
Tons particulate matter removed per year	116	--	--
First year average control cost ($/ton particulate matter removed)	$24,916	--	--
Incremental control cost ($/ton particulate matter removed)	$31,284	--	--

* LNB costs included in NOx BART analysis
[a] Based on vendor cost information
[b] From CH2M HILL database

Step 6: Evaluate Visibility Impacts

Improvements in visibility due to PM_{10} controls are minimal relative to uncontrolled emissions while combusting No. 6 fuel oil. In addition, the incremental costs related to adding a fabric filter and SDA are high. Impacts from the combustion of No. 2 fuel oil or natural gas without PM_{10} controls are expected to be less than those from the combustion of No. 6 fuel oil with emission controls.

Step 7: BART Determination

After reviewing the company's BART analysis, and based upon the information above ADEQ has determined that, for Unit 1, BART for PM_{10} is the use of PNG with a PM_{10} emissions limit of 0.0075 lb/MMBtu. Fuel oil will no longer be an authorized fuel for Unit 1. The PM_{10} emissions will be measured by conducting EPA method 201/202 tests.

D.3 SO_2 BART Analysis

SO_2 forms in the boiler during the combustion process and is primarily dependent on natural gas and fuel oil sulfur content. Emissions indicate that BART analysis is not required when ST1 burns PNG or fuel oil No. 2. Thus, the analysis in this section is limited to the case when ST1 is burning No. 6 fuel oil.

The EPA BART guidelines require that oil-fired units consider limiting the sulfur content of the fuel oil burned. Because current requirements for low-sulfur diesel fuel limit sulfur content to 0.05 percent, fuel switching will be analyzed as an SO_2 option for this study. Also, a dry FGD system with SO_2 reduction capability similar to the fuel switch option will be considered.

Step 1: Identify the Existing Control Technologies in Use at the Source

There is no SO_2 emissions control equipment installed on ST1.
Step 2: Identify All Available Retrofit Control Options

A broad range of information sources was reviewed in an effort to identify potentially applicable emission control technologies for SO_2 at ST1, including control technologies identified as BACT or LAER by permitting agencies across the United States.

Following elimination of the PNG and fuel oil No. 2 BART engineering analysis after RLBC database review, the following potential SO_2 control technology options were considered for application when ST1 burns fuel oil No. 6:

- Use of low-sulfur distillate oil (No. 2 fuel oil)
- Switch to PNG
- SDA

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ determined that all of the identified control technologies are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

Table 10.7 lists the various control technologies and estimated emissions rates.

Table 10.7 – Control Technology Options Evaluated

Technology	Expected Emission Rate (lb/MMBtu)	Estimated Cost (Millions $)
Current Baseline with No. 6 Fuel Oil	0.906	--
Low-Sulfur Fuel Oil	0.051	0
SDA	0.10	20
PNG	0.00064	0

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts

There is no energy impact associated with switching to low-sulfur diesel fuel; however, additional system pressure drop equivalent to 0.4 MW at a first-year cost of $71,832 will result from the installation of an SDA.

Environmental Impacts

There is no environmental impact associated with switching to low-sulfur diesel fuel. An SDA system generates solid waste requiring disposal.

Economic Impacts

A summary of the costs and amount of SO_2 removed for fuel switching is provided in Table 10.8. The complete Economic Analysis is contained in Appendix A of the AEPCO BART submittal.

Table 10.8 – SO_2 Control Costs			
Factor	**SDA**	**Switch to PNG**	**Switch to Low-Sulfur Fuel**
Total installed capital costs	$20,000,000[a]	$0	$0
Total first year fixed and variable O&M costs	$519,359	--	--
Total first year annualized cost	$3,811,706	--	--
Power consumption (MW)	0.40	--	--
Annual power usage (Million kW-hr/year)	1.4	--	--
SO_2 design control efficiency	89.0%	99.9%	91%
Tons SO_2 removed per year	1,587	--	--
First year average control cost ($/ton SO_2 removed)	2,446	--	--
Incremental control cost ($/ton SO_2 removed)	2,446	--	--

[a] Based on vendor cost information

Step 6: Evaluate Visibility Impacts

Improvements to deciview impacts from SO_2 controls are minimal relative to uncontrolled emissions while combusting No. 6 fuel oil. In addition, the incremental costs related to adding a fabric filter and SDA are high. Impacts from the combustion of No. 2 fuel oil or natural gas without SO_2 controls are expected to be less than those from the combustion of No. 6 fuel oil with emission controls.

Step 7: BART Determination

After reviewing the company's BART analysis and based upon the information above, ADEQ has determined that, for Unit 1, BART for SO_2 is the use of PNG with an SO2 emissions limit of 0.00064 lb/MMBtu. The limit would apply on a 30-day rolling average basis.

E. Steam Units 2 and 3

Steam Units 2 and 3 are substantially similar in design, construction and electrical output. While there are physical differences between the two units that will result in different costs for the same control technology, the overall differences were determined to be minimal. As a result, ADEQ has determined that it is appropriate to consider BART for both Units in a single section.

E.1 NO_X BART Analysis

During coal combustion, NO_X forms in three ways. The dominant source of NO_X formation is the oxidation of fuel-bound nitrogen (fuel NO_X). During combustion, part of the fuel NO_X is released from the coal with the volatile matter, and part is retained in the solid portion (char). The nitrogen chemically bound in the coal is partially oxidized to nitrogen oxides (NO and NO_2) and partially reduced to molecular nitrogen (N_2). A smaller part of NO_X formation is due to high temperature fixation of atmospheric nitrogen in the combustion air (thermal NO_X). A very small amount of NO_X is called "prompt" NO_X. Prompt NO_X results from an interaction of hydrocarbon radicals, nitrogen, and oxygen.

Step 1: Identify the Existing Control Technologies in Use at the Source

Both Steam Units 2 and 3 currently use over-fired air (OFA) and under-fired air systems to control NO_X emissions.

Step 2: Identify All Available Retrofit Control Options

The second step of the BART process is to evaluate NO_X control technologies with practical potential for application to Units 2 and 3, including those control technologies identified as Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) by permitting agencies across the United States. Both Steam Unit 2 and 3 NO_X emissions are currently controlled through the use of OFA and UFA systems added to the burners. The Units are dry turbo-fired boilers, with 12 Riley directional flame burners. The following potential NO_X control technology options were considered:

- New/modified state-of-the-art LNBs with advanced OFA
- Rotating opposed fire air (ROFA)
- Selective non-catalytic reduction system (Rotamix and SNCR)
- Selective catalytic reduction (SCR) system
- Neural Network Controls/Boiler Combustion Controls (Neural Net)

New LNBs with OFA System. The mechanism used to lower NO_X with LNBs is to stage the combustion process and provide a fuel-rich condition initially; this is so oxygen needed for combustion is not diverted to combine with nitrogen and form NO_X. Fuel-rich conditions favor the conversion of fuel bound nitrogen to N_2 instead of NO_X. Additional air (OFA or UFA) is then introduced upstream or downstream in a lower temperature zone to burn out the char.

ROFA. Mobotec markets ROFA as an improved second generation OFA system. Mobotec states that "the flue gas volume of the furnace is set in rotation by asymmetrically placed air nozzles." Rotation is reported to prevent laminar flow and improve gas mixing, so that the entire volume of the furnace can be used more effectively for the combustion process. In addition, the swirling action reduces the maximum temperature of the flames and increases heat absorption. Mobotec expects that enhanced mixing will also result in reduction in hot and cold furnace zones, improved heat absorption and boiler efficiency, and lower carbon monoxide (CO) and NO_X emissions. A typical ROFA installation will have a booster fan(s) to supply the high-velocity air to the ROFA boxes. Mobotec proposed one 2,100 horsepower fan for each unit, which would provide hot air at all boiler loads.

SNCR. With SNCR, an amine-based reagent such as ammonia—or more commonly urea—is injected into the furnace within a temperature range of 1,600 degrees Fahrenheit (°F) to 2,100 °F, where it reduces

NO_X to nitrogen and water. NO_X reductions of up to 40 to 60 percent have been achieved, although 15 to 30 percent is a more realistic expectation for most applications.

Reagent utilization, which is a measure of the efficiency with which the reagent reduces NO_X, can range from 20 to 60 percent, depending on the amount of reduction, unit size, operating conditions, and allowable ammonia slip. With low reagent utilization, low temperatures, or inadequate mixing, ammonia slip occurs, allowing unreacted ammonia to create problems downstream. Problems include rendering fly ash unsellable, and also reacting with sulfur to form ammonium bisulphate, which can foul heat exchanger surfaces or create a visible stack plume. Reagent utilization can have a significant impact on economics, with higher levels of NO_X reduction generally resulting in higher reagent utilization and higher operating cost. Reductions from higher baseline inlet NO_X concentrations are lower in cost per ton, but result in higher operating costs, due to greater reagent consumption.

SCR. SCR works on the same chemical principle as SNCR but instead uses a catalyst to promote the chemical reaction. Ammonia or urea is injected into the flue-gas stream, where it reduces NO_X to nitrogen and water. Unlike the high temperatures required for SNCR, in SCR the reaction takes place on the surface of a vanadium/titanium-based catalyst at a temperature range between 580° F to 750° F. Due to the catalyst, the SCR process is more efficient than SNCR and results in lower NO_X emissions. One type of SCR is the high-dust configuration, where the catalyst is located downstream from the boiler economizer and upstream of the air heater and any particulate control equipment. In this location, the SCR is exposed to the full concentration of fly ash in the flue gas that is leaving the boiler. However, for Units 2 and 3 the SCR could be installed after the hot-side ESP and before the air heater. In a full-scale SCR, the flue ducts are routed to a separate large reactor containing the catalyst. With in-duct SCR, the catalyst is located in the existing gas duct, which may be expanded in the area of the catalyst to reduce flue gas flow velocity and increase flue gas residence time. Due to the higher NO_X removal rate, a full-scale SCR was used as the basis for analysis at Units 2 and 3.

Neural Net Controls/Boiler Combustion Control. Review of neural net and improved boiler combustion control are combined for purposes of this analysis under the potential implementation of neural net boiler control system. Information regarding neural net controls was provided by NeuCo, Inc. While NeuCo offers several neural net products, CombustionOpt and SootOpt provide the potential for NO_X reduction. NeuCo stated these products can be used on most control systems, and can be effective even in conjunction with other NO_X reduction technologies. NeuCo predicts that CombustionOpt can reduce NO_X by 15 percent, and SootOpt can provide an additional 5 to 10 percent. Because NeuCo does not offer guarantees on this projected emission reduction, a nominal reduction of 15 percent was assumed for evaluation purposes.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the identified control technologies are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

Table 10.9 lists the various control technologies and estimated emissions rates.

Table 10.9 – Control Technology and Respective Emission Rates	
Control Technology	**Expected NO_X Emission Rate**
Neural Net/Boiler Combustion Control	15% reduction
New LNBs with OFA System	0.31 lb/MMBtu
ROFA	0.26 lb/MMBtu
SNCR	0.18 lb/MMBtu
SCR	0.07 lb/MMBtu

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

This step involves the consideration of energy, non-air quality environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts

Installation of LNBs and modification to the existing OFA and UFA systems are not expected to significantly impact the boiler efficiency or forced-draft fan power usage. Therefore, these technologies are not expected to have significant energy impacts.

The Mobotec ROFA system requires installation and operation of one 2,100 horsepower ROFA fan (1,566 kilowatts [kW] total) for each unit. Fuel Tech provided an estimate of 130 kW of additional auxiliary power, and the same estimate was used for Rotamix. SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase.

Non-Air Quality Environmental Impacts

Mobotec generally predicts that CO emissions, and unburned carbon in the ash, commonly referred to as loss on ignition (LOI), would be the same or lower than prior levels for the ROFA system.

SNCR and SCR installation could impact the salability and disposal of fly ash due to ammonia levels. Other environmental impacts involve the potential public and employee safety hazard associated with the storage of ammonia, especially anhydrous ammonia, and the transportation of the ammonia to the power plant site.

Economic Impacts

A comparison of the technologies on the basis of costs, design control efficiencies, and tons of NO_X removed is summarized in Table 10.10 for Unit 2 and Table 10.11 for Unit 3. The complete Economic Analysis is contained in Appendix A of the AEPCO BART submittal.

Table 10.10 – Control Technology Efficiency and Costs for Unit 2					
Factor	**LNB with OFA**	**ROFA**	**ROFA with Rotamix**	**LNB with OFA and SNCR**	**LNB with OFA and SCR**
Major Materials Design Costs (Million $)	$2.000	$3.627	$5.441	$6.830	$29.30
Total Installed Capital Costs (Million $)	$4.760	$9.616	$12.63	$12.54	$48.74
Total First Year Fixed and Variable Costs (Million $)	$0.080	$0.750	$1.024	$0.545	$1.466
Total First Year Annualized Cost (Million $)	$0.533	$1.664	$2.225	$1.738	$6.102
Power Consumption (MW)	-	1.57	2.07	0.50	1.00
Annual Power Usage (Kilowatt-Hr/Year)	-	12.6	16.6	4.0	8.0
NO_X Design Control Efficiency	34.2%	44.8%	61.8%	51.2%	85.1%
Tons of NO_X Removed	1,305	1,710	2,358	1,953	3,250
Average Cost ($/ton)	$408	$973	$944	$890	$1,878
Incremental Cost ($/ton)	$408	$2,793	$1,203	$301	$4,350

Table 10.11: Control Technology Efficiency and Costs for Unit 3					
Factor	**LNB with OFA**	**ROFA**	**ROFA with Rotamix**	**LNB with OFA and SNCR**	**LNB with OFA and SCR**
Major Materials Design Costs (Million $)	$2.000	$3.627	$5.441	$6.830	$29.30
Total Installed Capital Costs (Million $)	$4.760	$9.616	$12.62	$12.54	$48.74
Total First Year Fixed and Variable Costs (Million $)	$0.080	$0.719	$0.981	$0.525	$1.426
Total First Year Annualized Cost (Million $)	$0.533	$1.634	$2.182	$1.718	$6.062
Power Consumption (MW)	-	1.57	2.07	0.50	1.00
Annual Power Usage (Kilowatt-Hr/Year)	-	12.0	15.8	3.8	7.7
NO_X Design Control Efficiency	27.9%	39.5%	58.1%	46.5%	83.7%
Tons of NO_X Removed	926	1,312	1,929	1,543	2,778
Average Cost ($/ton)	$575	$1,246	$1,131	$1,113	$2,183
Incremental Cost ($/ton)	$575	$2,855	$1,203	$360	$4,572

Step 6: Evaluate Visibility Impacts

Tables 10.12 and 10.13 below show the total deciview reduction for the most impacted Class I area for Units 2 and 3 respectively. For Units 2 and 3, the most impacted Class I area is the Chiricahua Wilderness Area and National Monument.

Table 10.12 – Control Technology and Visibility Impact Reduction for Unit 2

Control	Deciview Reduction	Total Annualized Cost (Million $)	Cost per deciview reduced (Million $/dv)	Average Cost ($/ton)
Neural Net/Boiler Combustion Control	Unknown	Unknown	Unknown	Unknown
New LNB with OFA System	0.267	$0.533	$1.996	$408
ROFA	0.359	$1.664	$4.636	$973
ROFA with Rotamix	0.491	$2.225	$4.532	$944
LNB with OFA and SNCR	0.416	$1.738	$4.177	$890
LNB with OFA and SCR	0.676	$6.103	$9.028	$1,878

Table 10.13 – Control Technology and Visibility Impact Reduction for Unit 3

Control	Deciview Reduction	Total Annualized Cost (Million $)	Cost per Deciview Reduced (Million $/dv)	Average Cost ($/ton)
Neural Net/Boiler Combustion Control	Unknown	Unknown	Unknown	Unknown
New LNB with OFA System	0.206	$0.533	$2.586	$575
ROFA	0.298	$1.634	$5.484	$1,246
ROFA with Rotamix	0.436	$2.182	$5.004	$1,131
LNB with OFA and SNCR	0.356	$1.718	$4.825	$1,113
LNB with OFA and SCR	0.633	$6.062	$9.577	$2,183

Step 7: BART Selection

After reviewing the company's BART analysis, and based upon the information above, ADEQ has determined that, for Units 2 and 3 BART for NO_X is new LNBs with the existing OFA system with a NO_X emissions limit of 0.31 lb/MMBtu for both Units 2 and 3 on a 30-day rolling average basis.

E.2 PM_{10} BART Analysis

Step 1: Identify the Existing Control Technologies in Use at the Source

Both Steam Units 2 and 3 are currently equipped with hot-side Electrostatic Precipitators (ESPs).

Step 2: Identify All Available Retrofit Control Options

Steam Units 2 and 3 are currently equipped with hot-side ESPs. Historically, outlet ESP particulate emissions on Units 2 and 3 have ranged from approximately 0.007 to 0.045 lb/MMBtu. This wide range in outlet emissions can in part be attributed to the hot-side operation, as well as the wide variety of coals being burned in the boilers. Hot-side ESP effectiveness may also be impacted by sodium content in the ash.

Three retrofit control technologies have been identified for additional particulate matter control:

- Performance upgrades to existing hot-side ESP
- Replace current ESP with a fabric filter unit
- Install a polishing fabric filter after ESP

Performance Upgrades. Modifications to the hot-side ESPs, such as improving the rapping system, controller upgrades, conversion to cold-side operation, flue gas conditioning, wide plate spacing, addition of particle pre-charging system, etc., could be implemented to improve ESP particulate collection efficiency.

Replace Current ESP with a Fabric Filter Unit. Full-size pulse jet fabric filters could be installed as a replacement for the existing ESPs on Units 2 and 3. These fabric filters would be sized for approximately 3.5 or 4:1 Air to Cloth (A/C) ratio (actual cubic feet per minute of flue gas per square foot of fabric). An A/C ratio of 4:1 was used for this analysis. Fabric filters have been proven to provide highly effective and consistent particulate emissions reduction, with outlet emissions of approximately 0.015 lb/MMBtu. The ESPs would be removed from service with these replacement fabric filters.

Install a Polishing Fabric Filter. A polishing fabric filter could be added downstream of the existing ESPs on Units 2 and 3. One such technology is licensed by the Electric Power Research Institute, and referred to as a COHPAC (Compact Hybrid Particulate Collector). The COHPAC collects the ash that is not collected by the ESP, thus acting as a polishing device. The ESPs would be kept in service for the COHPAC fabric filter to operate effectively.

The COHPAC fabric filter is about one-half to two-thirds the size of a full-size fabric filter. Because the COHPAC has a higher A/C ratio (as high as 6 to 8:1), compared to a full-size pulse jet fabric filter (3.5 to 4:1), an A/C ratio of 6:1 was used for this analysis.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the identified control technologies are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

Table 10.14 lists the various control technologies and estimated emissions rates.

Table 10.14 – Control Technology and Respective Emission Rates	
Control Technology	**Expected PM_{10} Emission Rate**
ESP Upgrades	0.03 lb/MMBtu
Full size fabric filter	0.015 lb/MMBtu
Polishing Fabric Filter	0.015 lb/MMBtu

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

This step involves the consideration of energy, non-air quality environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts

Energy is required to overcome the additional pressure drop from both the fabric filter replacement and COHPAC fabric filter, and associated ductwork. Therefore, fan upgrades may be required for both alternatives to overcome the additional pressure drop. An estimated 6 to 8 inches of water pressure drop for the replacement fabric filter may be experienced, with 8 to 10 inches of water pressure drop likely for the COHPAC unit. The polishing fabric filter will also result in maintaining the existing ESP in service, which will result in power consumption in addition to what is required by the fabric filter replacement option.

COHPAC fabric filters on Units 2 and 3 would require approximately 1.3 MW of power each.

Energy impacts from ESP upgrades are unknown and would vary depending on the precipitator upgrade applied.

Non-Air Quality Environmental Impacts

There are no negative environmental impacts from precipitator upgrades, the addition of a replacement or COHPAC polishing fabric filter.

Economic Impacts

A comparison of the costs and PM_{10} removed for a replacement fabric filter or COHPAC polishing fabric filter are shown in Table 10.15 and 10.16 for Units 2 and 3 respectively. Specific costs for the precipitator upgrades were not evaluated as AEPCO has yet to evaluate the upgrades that may be applicable to Units 2 and 3. Capital cost information was provided by Alstom for both the polishing and replacement fabric filters. The complete Economic Analysis is contained in Appendix A of the AEPCO BART submittal.

Table 10.15 – Control Technology Efficiency and Costs for Unit 2			
Factor	**ESP Upgrades**	**Polishing Fabric Filter**	**Full Size Fabric Filter**
Major Materials Design Costs	Unknown	$6,666,667	$10,000,000
Total Installed Capital Costs	Unknown	$15,866,667	$23,800,000
Total First Year Fixed and Variable Costs	Unknown	$708,050	$623,824
Total First Year Annualized Cost	Unknown	$2,217,411	$2,887,867
Power Consumption (MW)	Unknown	1.30	1.00
Annual Power Usage (Kilowatt-Hr/Year)	Unknown	10.5	8.0
PM_{10} Design Control Efficiency	Unknown	66.67%	66.67%
Tons of PM_{10} Removed	Unknown	243	243
Average Cost ($/ton)	Unknown	$9,121	$11,878
Incremental Cost ($/ton)	Unknown	$9,121	$11,878

Table 10.16 – Control Technology Efficiency and Costs for Unit 3			
Factor	**ESP Upgrades**	**Polishing Fabric Filter**	**Full Size Fabric Filter**
Major Materials Design Costs	Unknown	$6,666,667	$10,000,000
Total Installed Capital Costs	Unknown	$15,866,667	$23,800,000
Total First Year Fixed and Variable Costs	Unknown	$682,996	$604,552
Total First Year Annualized Cost	Unknown	$2,192,357	$2,868,595
Power Consumption (MW)	Unknown	1.30	1.00
Annual Power Usage (Kilowatt-Hr/Year)	Unknown	10.0	7.7
PM_{10} Design Control Efficiency	Unknown	66.67%	66.67%
Tons of PM_{10} Removed	Unknown	231	231
Average Cost ($/ton)	Unknown	$9,471	$12,393
Incremental Cost ($/ton)	Unknown	$9,471	$12,393

Step 6: Evaluate Visibility Impacts

Tables 10.17 and 10.18 below show the total deciview reduction for the most impacted Class I area for Units 2 and 3 respectively. For Units 2 and 3, the most impacted Class I area is the Chiricahua Wilderness Area and National Monument.

Table 10.17 – Control Technology and Visibility Impact Reduction for Unit 2				
Control	**Deciview Reduction**	**Total Annualized Cost (Million $)**	**Cost per Deciview Reduced (Million $/dv)**	**Average Cost ($/ton)**
ESP Upgrades	Unknown	Unknown	Unknown	Unknown
Polishing Fabric Filter	0.085	$2.217	$26.09	$9,121
Full Size Fabric Filter	0.085	$2.888	$33.98	$11,880

Table 10.18 – Control Technology and Visibility Impact Reduction for Unit 3				
Control	**Deciview Reduction**	**Total Annualized Cost (Million $)**	**Cost per Deciview Reduced (Million $/dv)**	**Average Cost ($/ton)**
ESP Upgrades	Unknown	Unknown	Unknown	Unknown
Polishing Fabric Filter	0.094	$2.192	$23.32	$9,471
Full Size Fabric Filter	0.094	$2.869	$30.52	$12,390

Step 7: BART Selection

Based upon its review of the analysis provided by AEPCO, and the information provided above, ADEQ has determined that BART for PM_{10} emissions is upgrades to the existing ESP and a PM_{10} emissions limit of 0.03 lb/MMBtu for both Units 2 and 3. The upgrades to the existing ESP will involve a possible installation of a flue gas conditioning system, improvements to the scrubber bypass damper system, and implementing programming optimization measures for ESP automatic voltage controls. The PM_{10} emissions will be measured by conducting EPA Method 201/202 tests.

D.3 SO_2 BART Analysis

SO_2 forms in the boiler during the combustion process from the oxidation of the sulfur present in the coal, and is primarily dependent on coal sulfur content. The BART analysis for SO_2 emissions on Units 2 and 3 is described below.

Step 1: Identify the Existing Control Technologies in Use at the Source

Steam Units 2 and 3 currently have wet limestone scrubbers installed for SO_2 removal.

Step 2
: Identify All Available Retrofit Control Options

The following potential SO_2 control technology option was considered:

- Enhancement of current wet limestone scrubber or SDAS

Units 2 and 3 currently operate wet limestone scrubbers for SO_2 removal, with current emissions of 0.184 lb/MMBtu and 0.151 lb/MMBtu respectively. The EPA BART guidelines state that for existing units

with SO_2 controls achieving at least 50 percent SO_2 removal, cost-effective scrubber upgrades should be considered. EPA has recommended consideration of the following potential upgrades:

- Elimination of bypass reheat
- Installation of liquid distribution rings
- Installation of perforated trays
- Use of organic acid additives
- Improve or upgrade scrubber auxiliary system equipment
- Redesign spray header or nozzle

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the identified control technology upgrades are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

When evaluating the control effectiveness of SO_2 reduction technologies, each option can be compared against benchmarks of performance. In its BART analysis, AEPCO chose to compare its proposed technology upgrades to EPA's presumptive BART emission limitations. According to EPA's BART guidance documents, the presumptive limit for SO_2 on a BART-eligible coal-burning unit, used here as a point of reference, is 95 percent removal, or 0.15 lb/MMBtu.

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

Over the past several years AEPCO has completed several scrubber upgrades to improve performance, including the following:

- Elimination of flue gas bypass
- Splitting the limestone feed to both the absorber feed tank and tower sump
- Upgrade of the mist eliminator system
- Installation of suction screens at pump intakes
- Automation of pump drain valves
- Replacement of scrubber packing with perforated stainless steel trays

Dibasic acid additive was tested; however results did not show significantly higher SO_2 removal.

Energy Impacts

Upgraded operation of the existing wet limestone scrubber or SDAS system is not expected to result in any additional power consumption.

Environmental Impacts

There will be incremental additions to scrubber waste disposal and makeup water requirements and a reduction of the stack gas temperature if there is elimination of flue gas bypass.

Economic Impacts

There are no anticipated cost impacts attributable to upgraded scrubber operation.

Step 6: Evaluate Visibility Impacts

A Visibility Impact Analysis was not performed for SO_2 since the existing scrubbers are proposed as BART.

Step 7: BART Selection

After reviewing the company's BART analysis, and based upon the information above, ADEQ has determined that BART for SO_2 emissions is no new controls and an emission limit of 0.15 lb/MMBtu on a 30-day rolling average basis.

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XI. APS CHOLLA GENERATING STATION BART ANALYSIS AND DETERMINATION

A. Process Description

The APS Cholla Power Plant ("APS Cholla") consists of the following four electric generating units with a total generating capacity of 1,150 megawatts (MW).

- Unit 1: 125 MW
- Unit 2: 300 MW
- Unit 3: 300 MW
- Unit 4: 425 MW

Each unit is a coal-fired steam generating unit equipped with a tangentially-fired, dry-bottom boiler. Each of these Units burns bituminous or sub-bituminous coal to generate super-heated steam. This steam is then used to drive turbines/generators for producing electricity. Cholla purchases coal from the Lee Ranch and El Segundo mines.

B. Description of Emissions Units Subject to Best Available Retrofit Technology (BART)

Units 2, 3 and 4 are potentially subject-to-BART because:

1. These units belong to one of the 26 categorical sources;
2. These units were in existence on August 7, 1977;
3. Combined emissions of visibility impairing pollutants from all three of these Units - nitrogen oxides (NO_X), particulate matter less than 10 microns (PM_{10}), and sulfur dioxide (SO_2) - are greater than 250 tons per year for each pollutant.

C. Impact on Visibility

CALPUFF modeling was performed at 13 Class I areas that are located within 300 kilometers of Cholla Power Plant. The following table provides the baseline maximum impact on visibility in deciview.

Table 11.1 – Modeled Baseline Impact on Visibility

Affected Class I Area	Unit 2	Unit 3	Unit 4
Capital Reef NP	1.25	2.70	2.40
Grand Canyon NP	1.45	2.45	2.65
Petrified Forest NP	1.40	3.00	3.40
Sycamore Canyon WA	1.62	2.50	2.70
Gila WA	0.68	2.10	2.20
Mount Baldy WA	1.12	2.25	2.25
Sierra Ancha WA	0.91	1.90	2.15
Mazatzal WA	1.02	1.72	1.85

Table 11.1 – Modeled Baseline Impact on Visibility			
Affected Class I Area	**Unit 2**	**Unit 3**	**Unit 4**
Pine Mountain WA	1.20	1.75	1.88
Superstition WA	0.95	1.95	2.15
Galiuro WA	0.57	1.18	1.28
Mesa Verde NP	0.81	1.45	1.40
Saguaro NP	0.43	0.95	1.15

D. Nitrogen Oxides (NO_x) BART Analysis and Determination for Units 2, 3 and 4

Step 1: Identify the Existing Control Technologies in Use at the Source

The Cholla BART Analysis was completed in late 2007. At that time, the Units were equipped with Close-coupled Overfire Air (COFA). Overfire air is used to reduce NO_X by reducing excess air in the combustion zone. In a COFA system, air nozzles are immediately above the burners.

Low NO_X Burner (LNBs) and Seperated Overfire Air (SOFA) were installed on Units 2, 3 and 4 in March 2008, May 2009 and May 2008 respectively. LNBs and SOFAs are utilized for increased NO_X reduction.

Step 2: Identify All Available Retrofit Control Options

APS Cholla has identified the following available retrofit control technologies for NO_X control in Units 2, 3 and 4.

- LNB with Separate Overfire Air (SOFA) System
- LNB with SOFA and Selective Non-Catalytic Reduction (SNCR) System
- Rotating Opposed Flow Air system (ROFAs)
- ROFA with Rotary Mixing of Additives (Rotamix)
- LNB with SOFA and Selective Catalytic Reduction (SCR)

LNB with Separate Overfire Air (SOFA) System. Initial combustion takes place in fuel-rich condition so that the oxygen needed for combustion is not diverted to form NO_X. Additional air (separate overfire air) is then introduced in a lower temperature zone to burn out the char.

LNB with SOFA and Selective Non-Catalytic Reduction (SNCR) System. SNCR systems reduce NO_x by injecting reagent (ammonia or urea) into the furnace within a temperature range of 1600º to 2100º F. NO_X reduction of 40% to 60% can be achieved. Reagent utilization is a measure of efficiency with which the reagent reduces NO_X. Ammonia slip may occur due to lower temperatures, or inadequate mixing causing problems downstream. Potential problems include: rendering fly ash unsalable and reacting with sulfur to form ammonium bisulphate which can foul exchangers. The combination of LNB and SOFA with SNCR may achieve lower emission reductions than can be achieved by the individual technologies alone.

Rotating Opposed Flow Air System (ROFA). ROFA is an improved overfire air system. In this technology, the flue gas volume of the furnace is set in rotation by asymmetrically placed air nozzles. This rotation prevents laminar flow and improves gas mixing. As a result, the entire volume of the furnace is used more effectively for combustion process. A typical ROFA system requires a booster fan to supply high velocity air to the ROFA boxes.

ROFA with Rotary Mixing of Additives (Rotamix). ROFA along with Rotamix system provides enhanced mixing in the combustion chamber for optimal conditions to achieve multi-pollutant reduction. The turbulent mixing created by ROFA and Rotamix improves the efficiency of pollutant capture and reduces the stoichiometric amount of sorbent needed to reduce pollutants emissions.

LNB with SOFA and Selective Catalytic Reduction (CR). In SCR systems, vaporized ammonia (NH_3) injected into the flue gas stream acts as a reducing agent, achieving NO_X emission reductions when the gas stream is passed over a vanadium/titanium-based catalyst. The NO_X and ammonia react to form nitrogen and water vapor. The SCR ammonia-catalytic reaction requires a temperature range of 580-750° F.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the options identified above are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

The following table provides the NO_X emission rates that will be achieved with different feasible NO_X control technologies for Units 2, 3 and 4.

Table 11.2 – Achievable NO_X Emissions Rates By Technology

Control Technology	NO_X Emissions		
	Unit 2	Unit 3	Unit 4
	Pounds per MMBtu	Pounds per MMBtu	Pounds per MMBtu
LNB with COFA (Baseline)	0.50	0.410	0.415
LNB with SOFA	0.22	0.22	0.22
LNB with SOFA and SNCR	0.17	0.17	0.17
ROFA	0.16	0.16	0.16
ROFA with Rotamix	0.12	0.12	0.12
LNB with SOFA and SCR	0.07	0.07	0.07

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

Economic Impacts

The following Tables 3, 4 and 5 present the cost of compliance for the feasible technologies for Units 2, 3 and 4. The tables also report the predicted impact of these technologies on visibility [98th percentile deciview (dv)] reduction.

Energy Impacts

ROFA system will require a 3,300 HP fan for the supply of high-velocity air. Thus, there will be an additional power requirement of 130 KW.

SCR retrofit will cause additional pressure drop (6-8 inches water gauge) in the flue gas system due to catalyst.

LNBs and SOFA systems do not significantly impact boiler efficiency or power usage.

Non-Air Quality Environmental Impacts

SNCR and SCR installations could impact the salability and disposal of fly ash due to ammonia levels. At this time, APS Cholla sells its fly ash, and if sellability of the fly ash is impacted, costs associated with the proposed controls will increase. SCR and SNCR may also involve potential safety hazard associated with handling of anhydrous ammonia, and transportation of ammonia to the plant site.

Remaining Useful Life

Units 2, 3 and 4 have projected remaining lives of 40 years at each unit.

Step 6: Evaluate Visibility Impacts

CALPUFF modeling was performed at 13 Class I areas that are located within 300 kilometers of Cholla Power Plant the degree of that may be reasonably expected from the use of BART. The impacts are modeled for different NO_X control scenarios, combined with SO_2 and PM_{10} technologies. Since, as shown in Table 11.1, the Petrified Forest National Park is the most impacted area out of all the 13 Class I areas, Tables 11.3, 11.4 and 11.55 present the improvement in visibility (in deciview) in that area.

Table 11.3: Unit 2 Cost and Visibility Analysis							
NO_X Control Technologies	Emission Rate	NO_X Removal	Annualized Cost	1st yr Avg. Cost	Incremental Control Cost	Dv Impact for Max. Impacted Area (Petrified Forest NP)	
	lb/MMBtu	Tons/year	Million $	$/ton	$/ton	98th percentile dv reduction	million $/dv reduced
LNB with COFA (Baseline)	0.503	-	-	-	-	-	-
LNB with SOFA	0.22	3,314	$0.635	$192	$192	0.187	$3.40
LNB with SOFA and SNCR	0.17	3,900	$2.175	$558	$2,628	0.218	$9.98
ROFA	0.16	4,017	$2.297	$572	$1,043	0.232	$9.90
ROFA with Rotamix	0.12	4,485	$3.384	$755	$2,323	0.261	$12.97
LNB with SOFA and SCR	0.07	5,071	$9.625	$1,898	$10,650	0.287	$33.54

Table 11.4 – Unit 3 Cost and Visibility Analysis							
NO_X Control Technologies	Emission Rate	NO_X Removal	Annualized Cost	1st yr Avg. Cost	Incremental Control Cost	Dv Impact for Max. Impacted Area (Petrified Forest NP)	
	lb/MMBtu	Tons/year	Million $	$/ton	$/ton	98th percentile dv reduction	million $/dv reduced
LNB with COFA (Baseline)	0.41	-	-	-	-	-	-
LNB with SOFA	0.22	2,096	$0.635	$303	$303	0.126	$5.04
LNB with SOFA and SNCR	0.17	2,648	$2.157	$814	$2,756	0.164	$13.15
ROFA	0.16	2,758	$2.243	$813	$786	0.169	$13.27
ROFA with Rotamix	0.12	3,200	$3.308	$1,034	$2,409	0.198	$16.71
LNB with SOFA and SCR	0.07	3,751	$9.569	$2,551	$11,363	0.230	$41.61

Table 11.5 – Unit 4 Cost and Visibility Analysis							
NO_X Control Technologies	**Emission Rate**	**NO_X Removal**	**Annualized Cost**	**1st yr Avg. Cost**	**Incremental Control Cost**	**Dv Impact for Max. Impacted Area (Petrified Forest NP)**	
	lb/MMBtu	**tons/year**	**Million $**	**$/ton**	**$/ton**	**98th percentile dv reduction**	**million $/dv reduced**
LNB with COFA (Baseline)	0.42	-	-	-	-	-	-
LNB with SOFA	0.22	3,390	$0.820	$242	$242	0.207	$3.96
LNB with SOFA and SNCR	0.17	4,259	$2.852	$670	$2,338	0.265	$10.76
ROFA	0.16	4,433	$3.179	$717	$1,877	0.281	$11.31
ROFA with Rotamix	0.12	5,129	$4.537	$885	$1,951	0.336	$13.50
LNB with SOFA and SCR	0.07	5,998	$13.23	$2,206	$10,007	0.408	$32.43

Step 7: BART Selection

According to the Regional Haze Rule, only dV changes in excess of 1.0 dV are perceptible.

A review of the data presented in Tables 11.3, 11.4, and 11.5 indicates that CALPUFF model-predicted visibility improvements (delta dV) for all five NO_x control scenarios are less than 0.5 dV. For example, in the case of Unit 3, the dV changes range from 0.126 dV for the LNB with SOFA (Scenario 1) to 0.230 dV for LNB with SOFA and SCR (Scenario 5). The change in dV between the least expensive and most expensive NO_x control technologies (the two noted above) is only 0.104 dV. The corresponding capital costs are $5.4 million for LNB/SOFA and $82.8 million for LNB/SOFA with SCR.

Based on these facts and the five-factor analysis discussed above, ADEQ has concluded that LNB with SOFA constitute BART for NO_x emissions for Cholla Units 2, 3, and 4. The BART limit will be 0.22 lb/MMBtu on a 30-day rolling average basis.

E. PM_{10} BART

Step 1: Identify the Existing Control Technologies in Use at the Source

Unit 2 currently has a mechanical dust collector for control of PM_{10} emissions. Additional particulate matter control is provided by a venturi scrubber. Cholla 2 is currently able to achieve emission rate of 0.020 lb/MMBtu.

Unit 3 was previously equipped with a hot-side ESP and was able to achieve an emission rate of 0.015 lb/MMBtu of PM_{10}. The facility completed installation of a fabric filter in May 2009. With the installation of the fabric filter, the facility expects to consistently achieve an emission rate of 0.015 lb/MMBtu for PM_{10}.

Unit 4 was previously equipped with a hot-side ESP and was able to achieve an emission rate of 0.024 lb/MMBtu of PM_{10}. The facility completed installation of a fabric filter in May 2008. With the installation of the fabric filter, the facility expects to consistently achieve an emission rate of 0.015 lb/MMBtu for PM_{10}.

Step 2: Identify All Available Retrofit Control Options

Since Units 3 and 4 will be equipped with fabric filters, and fabric filters are considered the top control technology for reducing PM emissions. As a result, no other technology is considered for these two Units. The following retrofit technologies are considered for Unit 2:

- Electrostatic Precipitators
- Fabric Filters

Electrostatic Precipitator. An ESP operates by placing a charge on the particles through electrodes, and then capturing the charged particles on collection plates.

Fabric Filter. The flue gas passes through the bags to remove particulate matter. The bags are cleaned by initiating a pulse of air into the top of the bag. The pulse causes a ripple effect along the length of the bag and releases the dust cake from the bag surface into a hopper.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that both fabric filters and electrostatic precipitators are technically feasible options.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

Electrostatic Precipitator. ESPs are capable of achieving an emission rate of 0.015 lb/MMBtu. However, ESP operation is susceptible to particle resistivity. Particle resistivity is influenced by flue gas temperature. Thus, operational variations may not result in consistent compliance with the emission limit.

Fabric Filter. Fabric filters are proven to be highly effective and provide a consistent particulate matter reduction. The emissions at the outlet of fabric filter are expected to be less than 0.015 lb/MMBtu.

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

Economic Impact

Since Units 3 and 4 are already equipped with bag filters, no economic impact analysis is required. For Unit 2, since the facility has already decided to install a new bag filter in 2015, this is the only option considered for the economic analysis.

Table 11.6 – Economic Impacts for Unit 2

Control	Emission Rate (lb/ MMbtu)	Total Emission (Tons/ Yr)	Total Emission Reduction (Tons)	Annualized Cost ($MM)	Cost/ Ton ($)	Incremental Cost/ton ($/ton)
Baseline (no control)	0.020	234	-	-	-	-
Fabric Filter	0.015	176	58	9.40	160,747	160,747

Energy Impacts

Since Units 3 and 4 are already equipped with bag filters, no energy impact analysis is required. For Unit 2, the installation of new fabric filter will result in additional pressure drop across the filter and associated duct work. Thus, additional power will be required. This is likely to be offset by the removal of mechanical dust collector and venturi scrubber.

Non-Air Quality Environmental Impacts

There are no negative environmental impacts from the installation of new fabric filter.

Step 6: Evaluate Visibility Impacts

The installation of a fabric filter is the only option considered for BART for all the 3 units.

Step 7: BART Selection

Based upon its review of the company's BART analysis and the information provided above, the Department has determined that, fabric filter with an associated emission limit of 0.015 lb/MMBtu is the BART for control of PM_{10} for Units 2, 3 and 4. The PM_{10} emissions will be measured by conducting EPA Method 201/202 tests.

It should be noted that the dollar per ton value of 160,747 for the installation of a fabric filter for Unit 2 would normally not be considered as a cost-effective number by the Department in a BART evaluation but is being chosen as BART because of the company's commitment to install the fabric filter by 2015.

F. Sulfur Dioxide (SO_2) BART

Step 1: Identify the Existing Control Technologies in Use at the Source

Unit 2. This unit is equipped with four venturi flooded disc scrubbers/absorber with lime reagent for SO_2 control. Currently, APS Cholla is able to achieve 0.14 lb/MMBtu to 0.25 lb/MMBtu of SO_2 on Unit 2.

Unit 3. This unit did not have any SO_2 control technology when the BART analysis was completed in late 2007. The facility installed a new wet lime scrubber in May 2009 to capture and treat all flue gases. This will result in Unit 3 consistently meeting an emission limit of 0.15 lb/MMBtu.

Unit 4. This Unit was previously operating with 36% flue gas scrubbing with emission rate of 0.734 lb/MMBtu. The facility installed a new wet lime scrubber in May 2008 to capture and treat all flue gases. This will result in Unit 4 consistently meeting an emission limit of 0.15 lb/MMBtu.

Step 2: Identify All Available Retrofit Control Options

Unit 2. The facility plans to remove the venturi section of the scrubber and considered a wet lime scrubber section for possible operational upgrades. Installation of bag filter as a part of BART will improve the performance of scrubber due to decreased plugging of scrubber. The facility expects to achieve 0.15 lb/MMBtu consistently with these operational upgrades.

Unit 3. In late 2007, APS Cholla identified the following available retrofit control technologies for SO_2 control in Unit 3:

- Dry Flue Gas Desulfurization (FGD) System
- Dry Sodium Sorbent Injection
- Wet Lime Scrubber

Dry Flue Gas Desulfurization (FGD) System. Dry FGD is based on the spray drying of lime slurry into flue gas. The SO_2 is absorbed into the fine spray droplets and reacts with the calcium to form dry calcium sulfite or sulfate. This is collected by the particulate control device along with fly ash.

Dry Sodium Sorbent Injection. Dry duct injection of sodium carbonate or sodium bicarbonate into the flue gas is utilized to remove SO_2. Unreacted/reacted sorbent is collected by the particulate control device along with fly ash.

Wet Lime Scrubber. SO_2 laden flue gas enters a scrubber where it is sprayed with lime slurry. The SO_2 reacts with the calcium to form calcium sulfite or sulfate which is removed and disposed off as scrubber waste, or reclaimed as gypsum.

Subsequently, Cholla intalled a new Wet Lime Scrubber on Unit 3 in May 2009. Therefore, the new wet lime scrubber, as described above, is the only retrofit control technology considered for this unit.
Unit 4. The wet lime scrubber, as described above, is the only retrofit control technology considered for this unit.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the control options identified above are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

Dry FGD System. This technology is estimated to achieve 90% control efficiency. Thus the achievable emission rate with this technology is 0.25 lb/MMBtu.

Dry Sodium Sorbent Injection. Maximum SO_2 removal efficiency for this technology is 75%. Thus, for an initially uncontrolled emission rate of 2.5 pounds/MMBtu, the achievable emission rate with this technology is 0.625 lb/MMBtu.

Wet Lime Scrubber. Wet lime scrubbers are capable of very high SO_2 removal efficiency. Based on a 95% control efficiency, the wet lime scrubber can achieve the emission rate of 0.15 lb/MMBtu.

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

Economic Impact

Unit 2. Only operational upgrades will be done on the existing wet lime scrubber. Hence there is no economic impact.

Unit 3. The installation of a new wet lime scrubber was completed in May 2009. This technology provides the maximum reduction in SO_2 emissions. The wet lime scrubber is the only option considered for economic analysis.

Table 11.7 – Economic Impacts for Unit 3

Control	Emission Rate (lb/ MMbtu)	Total Emission (Tons/ Yr)	Total Emission Reduction (Tons)	Annualized Cost (Million$)	Cost/ Ton ($)	Incremental Cost/ton ($/ton)
Baseline (no control)	1.00	11,033	-	-	-	-
Wet Lime scrubber	0.15	1,655	9,378	$8.80	936	$936

Unit 4. The facility has completed the installation of a new wet lime scrubber in May 2008. Thus, there is no economic impact that needs to be assessed.

Energy Impacts

There will be no energy impact for Units 2, 3, and 4 as these scrubbers are already in place.

Non-Air Quality Environmental Impacts

There will be no non-air quality environmental impact for Units 2, 3, and 4 as these scrubbers are already in place.

Step 6: Evaluate Visibility Impacts

Wet lime scrubber is the only option considered for BART for Units 2, 3 and 4.

Step 7: BART Selection

Based upon its review of the BART analysis provided by the company, and the information provided above, the Department has determined that wet lime scrubbers with an associated emission limit of 0.15 lb/MMBtu on a 30-day rolling average basis is the BART for control of SO_2 for Units 2, 3 and 4.

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XII. ASARCO HAYDEN SMELTER BART ANALYSIS AND DETERMINATION

A. Process Description

According to EPA's Air Pollution Manual (AP-42) Section 12.3.1, copper mining produces ores that contain less than 1 percent copper. In order to produce copper, the mined ore must be concentrated through crushing, grinding and flotation purification, which results in an enriched ore that contains approximately 15 to 35 percent copper. This is often times referred to as "concentrate".

A typical pyrometallurgical copper smelting process includes 4 steps: roasting, smelting, concentrating and fire refining. Ore concentrate is first roasted to reduce the number of impurities in the concentrate, including sulfur and some heavy metals. The Hayden Smelter introduces a dried concentrate feed, along with combustion oxygen, into an INCO oxygen flash furnace. In this process, the charge of concentrate is mixed with a siliceous flux (often times a low-grade copper ore) and then heated in air to approximately 650 °C (1200 °F). This process eliminates 20 to 50 percent of the sulfur in the concentrate by converting the sulfur into sulfur dioxide (SO_2). The remaining material that leaves the INCO oxygen flash furnace is typically called matte, which is tapped from the furnace, flowing down ventilated launders into ladles that are staged below the furnace's floor. Matte typically contains 35 to 65 percent copper. Once the ladles are filled, they are moved to the converter aisle for transferring the molten matte into the converters. The slag produced by this process is skimmed and removed to a slag pot for delivery to the slag cooling area.

In its converter aisle, the Hayden smelter utilize five Pierce-Smith batch converters in order to produce blister copper by eliminating the remaining iron and sulfur that is present in the material. The ladles filled with matte from the furnace process are carried by crane into the converter aisle, and are then used to dump the molten material into the converters. Once filled, air is blown through the molten matte. Flux (silica) and other materials are added at various times during the process in order to regulate the temperature, and to facilitate the chemical reactions that allow the formation of an iron/silica slag.

The molten bath is allowed to "blow" until sufficient slag has formed on the surface. Operators will then roll the converter out in order to skim the slag off of the top. Additional matte, siliceous flux and scrap metal will again be added to the bath, and then the converter will be rolled back in to continue blowing. After several skimming processes, the converter will be filled with an adequate amount of relatively pure white metal. A final air blast will then be used to oxidize the copper sulfide to produce SO_2 and blister copper which is generally 98 to 99 percent pure copper. Impurities in blister copper often includes gold, silver, antimony, arsenic, bismuth, iron, lead, nickel, selenium, sulfur, tellurium, and zinc.

Each converter at the Hayden smelter is equipped with primary and secondary hooding systems. The primary hooding systems are designed to capture the SO_2 emissions that are emitted while the converters are "rolled-in". These SO_2 gases are then routed through a dust removal system, and then sent to the acid plant for treatment and conversion into sulfuric acid. The secondary hooding systems are designed to capture fugitive gases that escape the primary hood, or are emitted when the converter is "rolled-out" for skimming and charging. Gases that are collected by the secondary hooding are directed to a baghouse for dust removal, and are then exhausted to the atmosphere via the facility's 1,000 foot stack.

Once the blister copper has been produced, the Hayden smelter transfers the blister copper to the anode furnaces via ladle and overhead crane. The anode casting furnace accepts two to three charges from the converter aisle. Once filled, air is introduced into the flash furnace in order to further refine the copper. Impurities within the copper bath form an oxide slag which is removed from the furnace and returned to the converters. After the slag is removed and is no longer forming, natural gas is bubbled through the molten bath to remove any excess oxygen. The resultant purified copper (approximately 99% pure) is

then cast into specifically designed shapes and shipped by rail cars and trucks to off-site refineries for final processing.

B. Description of Emissions Units Subject-to-Best Available Retrofit Technology (BART)

On July 13, 2007, the Arizona Department of Environmental Quality sent a letter to ASARCO, Inc. identifying the following emissions as potentially subject-to-BART:

Table 12.1 – ADEQ Identified Potentially Subject-to-BART Pollutants and Emissions Units

Emissions Unit(s)	Pollutants Potentially Subject-to-BART
Converters 1-5	SO_2, PM_{10}
Anode Furnaces 1-3	SO_2, PM_{10}

On October 1, 2007, ASARCO responded stating that several of the emissions units were inappropriately identified as potentially Subject-to-BART. According to ASARCO's records, the company had operated three of the converters prior to the 1962 BART window. ASARCO went on to state that one of the three converters was enlarged from 13 x 32 feet to 13 x 35 feet in 1965, and that converters #1 and #4 were added in 1968, making the determination that "two or three of five are date eligible." ASARCO also stated that Anode Furnaces #1 and #2 were constructed in 1972, in the BART window, but asserted that Anode Furnace #0 was constructed in 2001, and was therefore not eligible for BART consideration.

ASARCO did not provide records in the October 1, 2007, letter demonstrating that its statements were indeed true. ADEQ's research of historical smelter logs, however, revealed that ASARCO did indeed operate three converters before 1962. ADEQ was also able to confirm that the date of construction for Anode Furnace #0 was 2001. As a result, ADEQ concurs with ASARCO's assessment of the BART-eligible emissions units, with the clarification that the converter that was enlarged in 1965 is considered BART-eligible. As a result, three converters and two Anode furnaces are considered BART-eligible.

As noted Section VI.C ADEQ determined that the potential emissions of PM_{10} were not sufficient to determine that the ASARCO Hayden smelter was subject-to-BART for that pollutant. Emissions of SO_2 from the facility, on the other hand, were determined to be subject-to-BART.

C. STREAMLINED SO_x BART ANALYSIS

Step 1: Identify the Existing Control Technologies in Use at the Source

According to Air Quality Permit 1000042, issued by ADEQ on October 9, 2001, the ASARCO Hayden smelter has installed and operates the following control technologies on the equipment subject-to-BART (Table 12.2):

Table 12.2 – Current Air Pollution Control Equipment and Emission Limits for Equipment Subject-to-BART at the Hayden Smelter

Emissions Units Subject-to-BART	Current Control	SO_x Emission Limit
Converters (three)	1. Primary hooding	1. Multi Point Roll Back Rule

Table 12.2 – Current Air Pollution Control Equipment and Emission Limits for Equipment Subject-to-BART at the Hayden Smelter		
Emissions Units Subject-to-BART	**Current Control**	**SO_x Emission Limit**
	2. Secondary hooding 3. Double contact acid plant	[A.A.C. R18-2-715(F)(2)(b)]
Anode Furnaces #1 and #4	No controls	1. Multi Point Roll Back Rule [A.A.C. R18-2-715(F)(2)(b)]

In addition to identifying the above controls for the BART-eligible equipment at the Hayden primary copper smelter, ADEQ also determined that it is important to note the process changes and control equipment that have been installed over time at the facility.

According to ADEQ's *Final Hayden Sulfur Dioxide Nonattainment Area State Implementation and Maintenance Plan*, dated June 2002, prior to 1971, all smelting operations process gasses from the facility were emitted into the atmosphere after electrostatic precipitators removed the particulate matter from the gases. In 1971, however, the company installed an acid plant as an SO_2 control for primary converter gases. According to sulfur balance information from the time period, SO_2 emissions from the facility were well in excess of 100,000 tons per year.

In 1983, the company undertook a series of additional improvements, including the replacement of twelve multiple-hearth roasters and two reverberatory furnaces, replacing them with an INCO Flash smelting furnace. At the same time, ASARCO installed a 650 ton per day oxygen plant that would enrich the smelting process gasses. Based upon this addition, the company was able to replace the existing single contact acid plant with a new double-contact acid plant. The emissions reductions resulting from these projects were estimated to be 63,584 tons per year of SO_2. According to ASARCO's calculations, the double-absorption acid plant recovers 99.81 percent of the SO_2 emissions that are vented to it.

In 1992, ASARCO made a modification to the smelter's existing gas handling system, and installed an $18.4 million wet gas handling system. This modification allowed the flash furnace off gas to be treated at temperatures that are less than 200° F, approximately 400° F less than the previous system. Due to the lower temperatures, the volume of gas being vented from the flash furnace was reduced, enabling the acid plant to provide additional ventilation to the converters. This additional ventilation allowed the secondary hoods to draw capture more SO_2 emissions from the converter building.

According to ADEQ's *Final Hayden Sulfur Dioxide Nonattainment Area State Implementation and Maintenance Plan*, dated June 2002, the complete list of SO_2 Process and Control Technologies employed by the Hayden primary copper smelter throughout the years is as follows (Table 12.3):

Table 12.3 – Implementation of SO_2 Process and Control Technology	
Year	**Equipment**
1971	Installation of No. 1 Acid Plant.
1972	Acid Plant Mist Precipitator Modification. Installation of Reverberatory Vent Fans to improve ventilation.
1973	Installation of Acid Coolers (Crane) for improved acid plant performance and Matte Fume Vent to improve the capture of fugitive emissions.

Table 12.3 – Implementation of SO_2 Process and Control Technology	
Year	**Equipment**
1974	Installation of Converter Spray Chamber for particulate removal and Plate Heat Exchanger.
1975	Matte Fume Enclosing to improve the capture of fugitive emissions.
1976	Installation of Separator - Demister to improve acid plant performance.
1978	Installation of Flue Gas Sampling Station.
1980	Installation of secondary hooding on the converters to minimize release of fugitive emissions directly to atmosphere.
1983	Replacement of multiple-hearth roasters and reverberatory furnaces with an Inco flash smelting furnace and gas handling equipment including slag skimming hoods, matte tapping hoods, and slag return hoods at the flash furnace for improved sulfur recovery. Installation of gas cleaning mist precipitators.
1983/1984	Installation of Monsanto acid plant No. 2 for treatment of all primary process gases.
1988	Installation of acid plant APV Heat Exchanger to improve gas cleaning performance.
1989	Electric slag cleaning vessel with an SO_2 control device; a caustic scrubber that controls a portion of the overall SO_2.
1991	Shutdown of acid plant No.1. Repair of a gas-to-gas heat exchanger leak at the acid plant. Repaired converter flues; replaced primary converter hoods and jackets; rebuilt all units in the Cottrell electrostatic precipitator; installed concrete sumps and improved sprays in the gas spray chamber of the acid plant to reduce fugitive SO_2 emissions.
1993	Upgrade of acid plant mist precipitator and acid plant intermediate fan.
1993	Modification of flash furnace uptake and replacement of cooling fins on the settling chamber to prevent the generation of fugitive emissions caused by inadequate cooling.
1995	Replacement of acid plant heat exchanger and retube of cold heat exchanger.
1997	Retube of Tail Gas Reheater Heat Exchanger.
1998	Installation of wet gas handling system for improved treatment of furnace emissions. Installation of new Hot IP Heat Exchanger; Cold IP Heat Exchanger; SX Distribution in IP Absorbing Tower; Foxboro IA distributive process control
1999/2000	Redesign of converter primary hood doors. The gaps in the primary hoods at the converter mouths were redesigned and a flexible seal installed to minimize the escape of fugitive emissions to the secondary hooding system.
2000	CEM Upgrade (Stack Monitors)

Step 2 - 6: Streamlined Analysis

On October 1, 2007, ASARCO submitted a letter stating:

"During the deliberations of the Market Trading forum of the Western Regioanl Air Partnership (WRAP), all parties involved including ADEQ and the U.S. Environmental Protection Agency (EPA), agreed that the controls and emissions limitation for primary copper smelters already met BART for SO_2. This was reflected in the milestones included in the State Implementation Plan (SIP) that ADEQ submitted to EPA under 40 CFR 51.309 (Section 309 SIP). The milestones being proposed for inclusion in the model 308 SIP currently being developed by the WRAP include an allowance of 26,000 tons of SO_2 for the Hayden smelter and are based on the fact that the smelter is at or beyond the BART requirements."

On November 27, 2007, the only other batch primary copper smelting operation in the Western United States, Phelps Dodge Miami Incorporated, submitted a letter to ADEQ indicating that in December 2003, the Western Regional Air Partnership (WRAP) had made a finding that "[a] double-contact acid plant will be considered the appropriate retrofit control equipment…" for SO_2 emissions. In support, PDMI referred ADEQ to a December 2002 report from E.H. Pechan & Associates, Inc. entitled *WRAP Market Trading Forum Non-Utility Sector Allocations Final Report from the Allocations Working Group*.

ADEQ reviewed the December 2002 report, and found that, at the time the report was published, the WRAP did state that "[a] double contact acid plant is considered the appropriate retrofit control equipment (all smelters in the western States are currently equipped with double contact acid plants.)" In addition, the report noted that there were six primary copper smelters in the WRAP region. Of the six, five were near copper mines in the southwest United States and use a batch process to produce copper. Of these five, only two of the smelters were producing copper, "…(the ASARCO smelter in Hayden, Arizona and the Phelps Dodge smelter in Miami, Arizona.)"

The WRAP's report also stated that the sixth smelter, Kennecott Utah Copper Corporation's operation near Garfield, Utah, was constructed in the mid 1990's and that it uses a flash copper converting technology. This flash copper converting technology allows copper to be produced in a continuous process.

ADEQ's analysis of the copper smelting industry in 2009 in the United States has revealed that there are currently three operating copper smelters. Those smelters are the ASARCO smelter in Hayden, Arizona, the Freeport McMoRan (formerly Phelps Dodge) smelter in Miami, Arizona, and the Kennecot Utah Copper Corporation's facility near Garfield, Utah. No other copper smelters have operated since the time that the WRAP's report has been published, and ADEQ is unaware of any plans to restart any of those smelters in the near future.

As previously noted, ADEQ's review of the Kennecott Utah Copper Corporation's operation has led to the determination that the continuous production of blister copper is a fundamentally different process than the process employed by ASARCO's Hayden Smelter. ADEQ has also determined that BART does not contain a requirement that the source be redesigned when the Agency considers the available control alternatives. As a result, ADEQ has concluded that it is not necessary to consider the use of Kennecott Utah Copper Corporation's process as a potential BART alternative.

Emissions from the Hayden smelter have varied over the years due to a number of factors, including the price of, and demand for, copper. According to the *2018 SO_2 Emissions Evaluation For Non-Utility Sources Final Report* provided by Pechan to the WRAP's Stationary Sources Joint Forum, historical SO_2 emissions from the ASARCO Hayden smelter are as follows:

Table 12.4 – Annual SO_2 Emissions from the ASARCO Hayden Smelter.	
Year	**SO_2 Emissions (Tons Per Year)**
1990	29,814
1996	33,124
1998	22,077
2000	16,753
2003	18,977
2004	19,395

As noted in Table 12.4, SO_2 emissions from the Hayden smelter have varied since 1990. The ASARCO Hayden smelter is considered a custom smelter, and while it obtains some feed of concentrates from its own mines, it also processes materials from other copper mines within the region. The variability of the SO_2 emissions appears to be correlated with the price of copper, which was low in the late 1990s and early 2000s. By 2003, however, copper prices had recovered, accounting for the increasing emissions noted in 2003 and 2004.

According to ADEQ's *Final Hayden Sulfur Dioxide Nonattainment Area State Implementation and Maintenance Plan*, dated June 2002, the process changes and installation of air pollution controls through the years has resulted in an increased overall SO_2 control efficiency at the Hayden primary copper smelter. Since the 1970s, the SO_2 control rate has risen from approximately 32% to approximately 42% with the installation of the double contact acid plant in the mid-1970s, to approximately 92% as a result of the activities identified in Table 5. Conversely, estimated SO_2 emissions from the facility fell from approximately 200,000 tons per year in the early 1970s, to less than 25,000 tons per year at the current time.

A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) revealed that there are no emission limitations or air pollution control devices that have been approved for anode furnace operations. Additionally, there are no emission limitations or air pollution control devices that have been approved for copper converters since the installation of the Double Contact Acid Plant in 1974. In addition, the only two remaining primary copper smelting operations that use batch converters are in Arizona and are subject to ADEQ's jurisdiction. Since the installation of the Double Contact Acid Plant there have been no changes at either the ASARCO Hayden smelter or the Freeport McMoRan Miami smelter that have triggered Prevention of Significant Deterioration review for sulfur oxides (SO_x). As a result, ADEQ has determined that the most stringent control available to control SO_x emissions from primary copper smelting operations is the Double Contact Acid Plant.

Step 7: Select BART

Based upon ADEQ's review of all of the above, ADEQ concurs with ASARCO's conclusion that the installation and operation of the double contact acid plant with the New Source Performance Standard of 650 ppm averaged over a 6-hour period constitutes BART for SO_2.

XIII. FREEPORT-MCMORAN MIAMI INC (FMMI) SMELTER (FMMI SMELTER) BART ANALYSIS AND DETERMINATION

A. Process Description

According to EPA's Air Pollution Manual (AP-42) Section 12.3.1, copper mining produces ores that contain less than 1 percent copper. In order to produce copper, the mined ore must be concentrated through crushing, grinding and flotation purification, which results in an enriched ore that contains approximately 15 to 35 percent copper. This is often referred to as "concentrate". In general, most concentrates processed at the FMMI primary copper smelter are equal parts (e.g., one third) sulfur, copper and iron.

At the FMMI smelter, the pyrometallurgical copper smelting process is a four step process consisting of smelting, slag separation, converting and fire refining. The concentrates are fed to the IsaSmelt ® vessel with enriched air, fluxes and natural gas. In this step, the concentrate is converted from a solid feed to a molten metal mix of matte (impure copper) and slag at a temperature of approximately 2300 F (1260 C). This mixture is composed of copper sulfide, copper oxide, iron sulfide, iron oxide, iron silicate and small amounts of trace metals such as gold, silver, lead and other metals. This mix is then transferred to an electric furnace where the matte and slag are separated.

In the electric furnace, electrical resistance is used to maintain temperature and facilitate the separation of slag from the matte by material density and retention time. The electrodes are submersed into the bath and a current is passed through the bath. Periodically, the slag is removed from the electric furnace and transferred to the slag stockpile. Concurrently, the matte (approximately 55% copper) is periodically transferred to the Hoboken Converters for further refining.

The FMMI smelter is the only copper smelter in the United States to use Hoboken converters. This type of converter is fitted with an inverted, u-shaped, side flue at one end that allows the siphoning of gases from the interior of the converter directly into an off gas collection system. This siphoning will also result in a slight vacuum at the mouth of the converter.

In the converters, the matte is converted to blister copper (approximately 99.7% copper) through a two step process of slag separation and oxidation. In the first step, the slag separation (or slag blow), the converters are charged with matte and periodic additions of silica fluxes to facilitate the separation of the residual iron and other impurities from the matte while blast air is introduced to oxidize the impurities. The slag generated in the converter (converter slag) is less dense than the copper portion of the matte, and "floats" on top. This converter slag can then be "skimmed" from the converter by rolling the converter out and pouring the slag into a ladle. The converter slag, which contains recoverable amounts of copper, is transferred to the electric furnace to ensure recovery of the copper values, from the slag. Throughout the slag blow, SO_2 is generated and captured. The captured SO_2 is transported via duct work to a sulfuric acid plant.

In the second stage of processing the matte, large quantities of enriched air (23+% oxygen) are blown into the matte to oxidize the copper sulfide, producing copper, copper oxide and sulfur dioxide. This step is also known as the copper blow. While the metals remain in the converter, the sulfur dioxide generated during the copper blow is transported via duct work to a sulfuric acid plant, which controls sulfur dioxide emissions by converting it to sulfuric acid. After several hours of oxidizing the matte, the sulfur levels are low enough that the matte is converted to blister copper (a mixture of primarily copper with some copper oxide and trace copper sulfide. The blister is then transferred to the Anode vessels for the final pyrometallurgical (fire) refining step.

During both the slag blow and the copper blow, secondary materials and scrap copper may be added to the converter for temperature control and to recover the copper values. Both slag and copper blows are highly exothermic, and the additions of secondary materials and scrap copper are important to control the temperature of the bath throughout the blowing cycles to prevent damage to the refractory and vessel.

In the anode vessels, the fire refining is a three step process of oxidation, slagging and reduction. In the oxidation step, air is introduced to the bath to remove residual sulfur. During the oxidations step, residual iron which may be present in low levels will be oxidized and create a high copper slag. This slag is skimmed from the anode vessel and returned to a converter to recover copper. After the skimming the slag, the bath is then reduced using a mixture of steam and natural gas. The natural gas removes excess oxygen from the molten copper to acceptable limits, while the steam prevents soot formation. After completion of the oxidation step, the copper is classified as anode copper (99.8+% copper) and is ready for casting into anodes, which are subsequently shipped from the smelter for electrolytic refining.

FMMI also operates a remelt/mold casting vessel. This vessel is similar to the anode vessel in that it has natural gas and steam injection installed for the control of oxidation of copper placed in it. The primary purpose of this vessel is to remelt scrap copper (copper foil, pipe and other grade 1 scrap), reduce oxygen to appropriate levels and pour molds used in the anode plant. The oxygen levels of the copper used in the molds must be very low to ensure that the molds can perform properly during the anode casting cycle. The natural gas and steam injection is used for oxygen control and prevention of soot formation. The vessel is also used as a holding vessel for molten blister copper in the event that there are operational issues at the anode plant with one of the two vessels. Typically, the blister is stored in the vessel, kept in a molten state in the event of an anode vessel having operational issues or taking longer for the fire refining cycle.

B. Description of Emissions Units Subject-to-Best Available Retrofit Technology (BART)

On August 3, 2008, FMMI provided a letter to ADEQ, presenting several bases for streamlining the BART review for the FMMI Smelter. According to the letter, FMMI stated that it believed that only the following emissions units at the facility constituted the "source subject-to-BART":

- The Electric Furnace (installed in 1974)
- The four Hoboken Converters (Converters Nos. 2-5) (installed in 1974) ; and
- The Remelt/Mold Pouring Vessel (installed in approx. 1974)

C. Streamlined PM_{10} BART Analysis

Step 1: Identify the Existing Control Technologies in Use at the Source

In an earlier letter dated July 17, 2007, FMMI, stated that "we do not disagree with the results that the Miami facility is subject-to-BART, because the visibility impact was greater than 0.5 dv at the Superstition Wilderness area…"

On August 3, 2008, FMMI provided another letter to ADEQ, presenting several bases for streamlining the BART review for the FMMI Smelter. According to the letter, FMMI stated that it believed that only the following emissions units at the facility constituted the "source subject-to-BART":

- The Electric Furnace (installed in 1974)

- The four Hoboken Converters (Converters Nos. 2-5) (installed in 1974) ; and
- The Remelt/Mold Pouring Vessel (installed in approx. 1974)

The FMMI smelter is a major source of Hazardous Air Pollutants (HAPs), and is therefore subject to the requirements of 40 CFR 63 Subpart QQQ, National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Primary Copper Smelting. According to Section 2.1 of the *National Emissions Standard for Hazardous Air Pollutants (NESHAP) for Primary Copper Smelters – Background Information for Promulgated Standards*, dated December 2001, the HAP emissions from primary copper smelters are primarily from metal impurities that naturally occur in copper ore concentrates. During the smelting process, the HAP metal species are eliminated in the molten slag that is tapped from the process vessels, or are vaporized and discharged in the process vessel off-gas. Upon the cooling of the off-gas, the volatilized HAP metal species condense, form aerosols, and behave as particulate matter.

The composition and concentration of HAP metals in the materials processed by the smelter tends to vary due to the different geological formations from where the copper ore was mined, and due to the different slag and scrap materials added during the processes. This inherent variability and unpredictability of the metal HAP compositions in the copper ores affects the amount of emissions of HAPs during the smelting process. As a result, EPA determined that prescribing individual numeric emissions limits for specific HAP metals was impractical, if not impossible.

EPA's alternative to promulgating specific HAP metal limitations in the NESHAP for Primary Copper Smelting was to use particulate matter as a surrogate pollutant for the HAP metals. All primary copper smelters and other smelter source categories are similar in the fact that the metal HAP compounds are a component of the particulate matter contained in the process off-gas discharged from the smelting and converting operations. In addition, controlling particulate matter process fugitive emissions will also result in the control of the metal HAPs that are contained in those emissions. Consequently, EPA determined that the emission limitations that are established to achieve a good control of particulate matter will also have the result of achieving a good control of metal HAP emissions. Therefore, EPA determined that it was appropriate to regulate particulate matter emissions as a surrogate for HAPs.

According to ADEQ Air Quality Permit Number 29622, the following particulate matter controls or emission limits apply to the emissions units that are subject-to-BART:

Table 13.1 – Current Air Pollution Control Equipment and Emission Limits for Equipment Subject-to-BART at the FMMI Smelter

Emissions Units Subject-to-BART	Current Control	Nonsulfuric Acid PM Emission Limit
Electric Furnace (Process Gases)	Acid plant tail gas system	6.2 mg/dscm (40 CFR 63.1444(b))
Electric Furnace (Captured Fugitive Emissions)	Wet scrubber and wet electrostatic precipitator	23 mg/dscm (40 CFR 63.1444(b)(2)(ii))
Hoboken Converters (Process Gases)	Acid plant tail gas system	6.2 mg/dscm (40 CFR 63.1444(b))
Hoboken Converters (Fugitive Emissions)	Copper converter capture system	4% opacity (40 CFR 63.1444(d)(4))
Remelt/Mold Pouring Vessel (similar to Anode Vessel)	Natural gas and steam injection	20% opacity from the Roofline (A.A.C. R18-2-702.B) or 33% Opacity (A.A.C.-R18-2-702.E)

When setting the particulate matter limits in the NESHAP, EPA determined that it was most appropriate to set the limitation based upon the particulate matter concentrations that do not include sulfuric acid. When sampling sulfuric acid plant tail gas using Method 5, condensed sulfuric acid mist and waters of hydration that were not driven off at the sampling temperature are included in the probe wash and filter catch, along with any metal HAP contained in the tail gas. As a result, EPA agreed that establishing and determining compliance with a total particulate matter emission limit based on Method 5 may include sulfuric acid mist condensables that are not related to the control or emission of metal HAPs. Given the gas stream characteristics of sulfuric acid plant tail gas, it was EPA's conclusion that Method 5B was the most appropriate test method to use for setting a particulate matter concentration limit that serves as a surrogate for metal HAP emissions contained in the tail gas from sulfuric acid plants.

Step 2 - 6: Streamlined Analysis

Section 2.3 of the *National Emissions Standard for Hazardous Air Pollutants (NESHAP) for Primary Copper Smelters – Background Information for Promulgated Standards*, dated December 2001, stated that Section 112(d)(2) of the Clean Air Act allows EPA to select as MACT, an alternative that is more stringent that the MACT floor. In order to select an alternative, EPA must take into consideration the cost and any non-air quality health and environmental impacts and energy requirements. EPA stated that the objective is to achieve a maximum degree of HAP emissions reductions without imposing unreasonable economic or other impacts.

In response to public comments on the matter, EPA stated that it was aware that there were a number of process modifications and changes for refining copper ores as of December 2001. EPA went on to state, however, that the application of the available modifications and processes were either not applicable to, or not commercially viable for, the existing primary copper smelters that use batch copper converting.

The first alternative that EPA was encouraged to consider was a requirement that all existing primary copper smelting facilities be required to replace their existing batch converters with continuous flash converters. After considering the arguments, however, EPA stated that in its "…judgment that even though a beyond-the-floor alternative requiring the existing batch converters to be dismantled and replaced with continuous flash copper technology may be technically feasible to implement at some or all of the existing smelters potentially subject to the rule, it is not an economically viable alternative. The total cost paid for building the new Kennecott smelter using continuous flash copper converting technology is on the order of one billion dollars. Even using as much of the existing smelter equipment as possible, the total capital investment of replacing the existing batch copper converting process at a smelter with the new continuous flash copper converting process would be in hundreds of millions of dollars. Given the current economic condition of the copper industry in the United States and the fact that none of the companies operating primary copper smelters using batch copper converting plans to change to flash copper converting, a regulatory requirement to do so would impose an enormous economic burden on these smelters." (at p. 2-8)

Other alternatives that EPA considered at the time of the NESHAP proposal included the use of a solvent extraction process and material substitution. After considering these options, however, EPA determined that they were technically infeasible. The solvent extraction process is designed to work for copper oxide ores, not copper sulfide ores. Material substitution is not an option as the HAP emissions from smelters are primarily related to impurities in the copper ores processed by smelter. ADEQ's analysis has revealed that EPA's logic continues to hold true. With respect to material substitution, although the HAP content might be impacted, it is not expected to have any impact on overall particulate matter emissions from the facility.

EPA did specifically address beyond-the-floor alternatives for copper converter departments based upon the control technologies that were used at the ASARCO El Paso smelter. When the El Paso smelter was operating, however, it utilized Pierce-Smith converters which are fundamentally different in design than Hoboken converters. Each of the smelters that employ the Pierce-Smith converters has a system of primary and secondary hoods that are used to capture emissions that emanate out of the mouths of the converters. Hoboken converters, on the other hand, utilize twiers inside the molten bath. In addition to providing the air necessary to oxidize the metals in the molten bath, the movement of the air within the converter, and the draw from the acid plant creates a vacuum at the mouth of the Hoboken converter. This redirects emissions that emanate from the interior of the converter to the acid plant, reducing the amount of fugitive emissions that are allowed to escape from the Hoboken converter. As a result, ADEQ determined that EPA's beyond-the-floor alternatives for the copper converter departments to be non-transferable to the FMMI smelter.

EPA also considered several other beyond-the-floor alternative controls for all of the primary copper smelters. The other options that were considered included the use of air curtain hoods for each batch converter, and to use a converter building evacuation system. In each of these alternatives, EPA proposed that the captured emissions would be vented to a baghouse control device. To support the analysis of the beyond-the-floor alternatives, EPA prepared estimates of the additional HAP emission reduction and the additional costs associated with implementing each of the two alternatives in place. Taking into consideration the costs of implementing either of the alternative, beyond-the-MACT-floor versus the level of additional emissions reductions that were estimated to be achieved, EPA concluded that there are no reasonable alternatives beyond the MACT floor for the control of process fugitive HAP emissions from existing batch converters. Although the HAP emissions make up only a portion of the particulate matter emissions from the smelter, ADEQ has determined that both options are also not appropriate for consideration for BART.

In Appendix A of the *National Emissions Standard for Hazardous Air Pollutants (NESHAP) for Primary Copper Smelters – Background Information for Promulgated Standards*, dated December 2001, EPA estimated the costs for both beyond-the-floor alternatives for the FMMI smelter as follows (Table 13.2):

Table 13.2 – 2001 Capital and Annual Costs for Alternative Control Strategies

Air Pollution Control Equipment	Estimated Costs (2001 Dollars)	
	Capital Costs	Annual Costs
1A. Air curtain hood vented to existing PM control device	$10 million	$3 million
1B. Air curtain hood vented to new baghouse	$16 million	$5 million
2. Building evacuation system vented through separate baghouse	$23 million	$8 million

The Bureau of Labor Statistics is responsible for, among other things, compiling information regarding inflation so that costs from previous years can be compared to modern day costs. On its Web site, the BLS has provided an inflation calculator[3]. According to the calculator's description: "the CPI inflation calculator uses the average Consumer Price Index for a given calendar year. This data represents changes in prices of all goods and services purchased for consumption by urban households. This index value has been calculated every year since 1913. For the current year, the latest monthly index value is used." Using this calculator, EPA's estimated costs in 2009 dollars would be as follows:

3 http://data.bls.gov/cgi-bin/cpicalc.pl

Table 13.3 – 2009 Capital and Annual Costs for Alternative Control Strategies		
Air Pollution Control Equipment	**Estimated Costs (2009 Dollars)**	
	Capital Costs	**Annual Costs**
1A. Air curtain hood vented to existing PM control device	$12.2 million	$3.6 million
1B. Air curtain hood vented to new baghouse	$19.5 million	$6.1 million
2. Building evacuation system vented through separate baghouse	$28.0 million	$9.7 million

At the time that the FMMI Smelter was modeled for PM emissions, ADEQ estimated potential smelter fugitive particulate matter emissions to be 48.55 pounds per hour, or a maximum of 212 tons per year. Given the relatively small amount of particulate matter reductions and the high costs associated with achieving those reductions, ADEQ has determined that the two alternative approaches considered by EPA remain overly burdensome due to costs alone.

Finally, according to Section 6.1 of the *National Emissions Standard for Hazardous Air Pollutants (NESHAP) for Primary Copper Smelters – Background Information for Promulgated Standards*, dated December 2001, EPA reviewed the estimated costs for the primary copper smelters to comply with the standards under the final rule. Although EPA concluded that some of the smelters would need to install additional air pollution control equipment to meet the standards, EPA did state that the FMMI smelter, which operates Hoboken converters, was believed to be able to meet the standards under the final rule without having to install additional air pollution control equipment (at p. 6-2). Through inspections and performance testing that has been conducted at the FMMI smelter since the time that the NESHAP was promulgated, ADEQ has confirmed that the smelter is capable of being operated in compliance with the non-sulfuric acid particulate matter emission limitations in the NESHAP.

After the EPA promulgated the NESHAP for Primary Copper Smelting, there have been significant changes to the industry. Of the six primary copper smelting facilities that were potentially covered by the NESHAP, only three remain: the Kennecott Smelter in Utah, the ASARCO smelter in Hayden, Arizona, and the FMMI smelter in Miami, Arizona. The other facilities have been shut down or permanently dismantled.

As noted before, the Kennecott Smelter's continuous flash converter process is considered a different subcategory of primary copper smelting, and inherently different from the batch converter process. As a result, the controls and emissions limitations for the Kennecott Smelter are not considered to be transferable to FMMI smelter.

A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) revealed that no emission limitations or air pollution control devices have been approved for copper smelters since the institution of the NESHAP for Primary Copper Smelting. In addition, the only two remaining primary copper smelting operations that use batch converters are in Arizona and are subject to ADEQ's jurisdiction. Since the implementation of the NESHAP for Primary Copper Smelting there have been no changes at either the ASARCO Hayden smelter or the FMMI smelter that have triggered Prevention of Significant Deterioration review. As a result, ADEQ has determined that the most stringent controls for particulate matter emissions is the NESHAP for Primary Copper Smelting.

Step 7: Select BART

Based upon ADEQ's review of all of the above, ADEQ concurs with FMMI's conclusion that the NESHAP for Primary Copper Smelting constitutes BART for PM emissions.

D. Streamlined SO_2 BART Analysis

Step 1: Identify the Existing Control Technologies in Use at the Source

In a letter dated July 17, 2007, FMMI stated that "we do not disagree with the results that the Miami facility is subject-to-BART, because the visibility impact was greater than 0.5 dv at the Superstition Wilderness area…"

On August 3, 2008, FMMI provided another letter to ADEQ, presenting several bases for streamlining the BART review for the FMMI Smelter. According to the letter, FMMI stated that it believed that only the following emissions units at the facility constituted the "source subject-to-BART":

- The Electric Furnace (installed in 1974)
- The four Hoboken Converters (Converters Nos. 2-5) (installed in 1974) ; and
- The Remelt/mold pouring Vessel (installed in approx. 1974)

Table 13.4 – Current Air Pollution Control Equipment and Emission Limits for Equipment Subject-to-BART at the FMMI Smelter.

Emissions Units Subject-to-BART	Current Control	SO_2 Emission Limit
Electric Furnace (Process Gases)	Acid plant tail gas system	1. 820 pounds per hour [Installation Permit #1232] 2. 3,515 tons per year [Installation Permit #1232] 3. 0.065% concentration by volume [40 CFR 60.163(a)]
Electric Furnace (Captured Fugitive Emissions)	Vent fume stack scrubber	1. 312 pounds per hour [Installation Permit #1232] 2. 1,336 tons per year [Installation Permit #1232]
Hoboken Converters (Process Gases)	Acid plant tail gas system	1. 820 pounds per hour [Installation Permit #1232] 2. 3,515 tons per year [Installation Permit #1232] 3. 0.065% concentration by volume [40 CFR 60.163(a)]
Hoboken Converters (Fugitive Emissions)	Smelter fugitives	1. 1,288 pounds per hour [Installation Permit #1232] 2. 5,517 tons per year [Installation Permit #1232]
Remelt/Mold Pouring Vessel	Natural gas and steam injection	20% opacity from the Roofline (A.A.C. R18-2-702.B) or 33% Opacity (A.A.C.-R18-2-702.E)

In addition to identifying the above controls for the BART-eligible equipment at the Miami primary copper smelter, ADEQ also determined that it is important to note the process changes and control equipment that have been installed over time at the facility.

According to ADEQ's *Final Miami Sulfur Dioxide Nonattainment Area State Implementation and Maintenance Plan*, dated June 2002, smelting operations began in Miami in 1915. Prior to 1974, the facility operated reverberatory furnaces and Peirce Smith converters in order to process copper sulfide ore from the nearby mines. In 1974, however, an electric furnace and Hoboken or siphon converters were installed for processing dried copper ore concentrates. A double contact acid plant was also installed in order to reduce the amount of SO_2 gases that are produced and emitted during the smelting and converting operations.

Prior to the installation of the double contact acid plant in late 1974, all process gasses from the smelting operations were emitted into the atmosphere after particulate matter was first removed by an electrostatic precipitator. Sulfur balance data available from that time period indicated that emissions of SO_2 from the Miami smelter were at least 34,000 lbs/hr (17 tons/hr). Actual emissions of SO_2 in the time period were estimated to be greater than 175,000 tons per year.

In 1992, the Miami smelter undertook a series of pollution control improvements, including the installation of an IsaSmelt® furnace and a 528 ton per day oxygen plant to enrich the smelting blast air.

In particular, the IsaSmelt® furnace eliminated the Miami copper smelter's use of the electric furnace as the primary device for smelting. In addition to increasing the facility's efficiency in producing copper, the IsaSmelt® conversion also improved the control of SO_2 emissions, as the new furnace comprises a closed vessel that is designed to contain the emissions from the process and route the process gasses generated to the acid plant. The result of these upgrades reduced the amount of fugitive SO_2 emissions being directly vented to the atmosphere from the electric furnaces that it replaced.

The double contact sulfuric acid plant is the predominant control device for process gases containing SO_2 at the Miami smelter. Process gases that are produced by the IsaSmelt® furnace, electric furnace, and converters are first cooled and cleaned of particulates in a gas scrubbing and electrostatic precipitator system in order to prepare the gas stream for treatment in the acid plant. After cooling and cleaning, the gas stream is dried and the SO_2 is converted by catalyst to sulfur trioxide (SO_3). The SO_3 is then adsorbed in circulating sulfuric acid to become sellable grade acid. Overall efficiency of SO_2 recovery from the acid plant has been found to be 99.9%

According to ADEQ's Final Miami Sulfur Dioxide Nonattainment Area State Implementation and Maintenance Plan, dated June 2002, the complete list of SO_2 Process and Control Technologies employed by the Miami primary copper smelter throughout the years is as follows (Table 13.5):

Table 13.5 – Implementation of SO_2 Process and Control Technology

Year	Equipment
1974	Replacement of reverberatory furnace and old converters with an Electric Furnace and Hoboken converters. Installation of a double contact acid plant for treatment of primary process gases.
1979 – 1981	Installation of Electric Furnace matte fume hoods at matte tapping area for capture of fugitive emissions.

Table 13.5 – Implementation of SO_2 Process and Control Technology	
Year	**Equipment**
1992	Installation of an IsaSmelt® Furnace and new oxygen plant. Installation of IsaSmelt® Furnace tapping launder covers, Electric Furnace slag tapping hoods, and vent fume scrubber for capture and control of fugitive emissions. Upgrade to increase the fan capacity of vent fume system for the two new fugitive emissions collection points. Upgrades to the acid plant and installation of a 3rd stage electrostatic mist precipitator at the acid plant and acid plant tail gas peaking scrubber for control of primary process emissions.
1997	Replacement of the old intermediate absorption tower at the acid plant with a new tower to increase the efficiency of the acid plant. The replacement is equipped with high efficiency (candle type) mist eliminators. Installation of a new catalytic converter, preheater, SO_3 cooler, product acid cooler and a final absorber, and replacement of two cold reheat exchangers at the acid plant.
1998	Intermediate absorber and cold reheat exchangers put into service.

Steps 2 - 6: Streamlined Analysis

On November 27, 2007, FMMI submitted a letter to ADEQ indicating that in December 2003, the Western Regional Air Partnership (WRAP) had made a finding that "[a] double-contact acid plant will be considered the appropriate retrofit control equipment…" for SO_2 emissions. In support, FMMI referred ADEQ to see a November 2002 report from E.H. Pechan & Associates, Inc. entitled *WRAP Market Trading Forum Non-Utility Sector Allocations Final Report from the Allocations Working Group*.

ADEQ reviewed the November 2002 report, and found that, at the time the report was published, the WRAP did state that "[a] double contact acid plant is considered the appropriate retrofit control equipment (all smelters in the Western States are currently equipped with double contact acid plants.)" In addition, the report noted that there are six primary copper smelters in the WRAP region. Of the six, five are near copper mines in the southwest United States and use a batch process to produce copper. Of these five, only two of the smelters were producing copper, "…(the ASARCO smelter in Hayden, Arizona and the Phelps Dodge (now FMMI) smelter in Miami, Arizona.)"

The WRAP's report also stated that the sixth smelter, Kennecott Utah Copper Corporation's operation near Garfield, Utah, was constructed in the mid 1990's and that it uses a flash copper converting technology. This flash copper converting technology allows copper to be produced in a continuous process.

ADEQ's analysis of the copper smelting industry in the United States has revealed that there are currently three operating copper smelters. Those smelters are the ASARCO smelter in Hayden, Arizona, the FMMI smelter in Miami, Arizona, and the Kennecott Utah Copper Corporation's facility near Garfield, Utah. No other copper smelters have operated since the time that the WRAP's report has been published, and ADEQ is unaware of any plans to restart any of those smelters in the near future.

As previously noted, ADEQ's review of the Kennecott Utah Copper Corporation's operation has led to the determination that the continuous production of blister copper is a fundamentally different process than the process employed by the FMMI Smelter. ADEQ has also determined that BART does not contain a requirement that the source be redesigned when the Department considers the available control alternatives. As a result, ADEQ has concluded that it is not necessary to consider the use of Kennecott Utah Copper Corporation's process as a potential BART alternative.

Emissions from the Miami smelter have varied over the years due to a number of factors, including the price of, and demand for, copper. According to the *2018 SO_2 Emissions Evaluation For Non-Utility Sources Final Report, October 2006,* provided by Pechan to the WRAP's Stationary Sources Joint Forum, historical SO_2 emissions from the Miami smelter are as follows (Table 13.6):

Table 13.6 – Annual SO_2 Emissions from the Miami Smelter

Year	SO_2 Emissions (Tons Per Year)
1990	5,676
1996	5,737
1998	6,097
2000	6,810
2003	8,005
2004	8,754

As noted in Table 13.6, SO_2 emissions from this facility have been steadily increasing since 1990. It is understood that the emissions increase trend can be attributed to increased utilization of capacity that was already available at the facility. Air Quality Control Permit Number 29622 issued by ADEQ on July 5, 2006, however, limits overall SO_2 emissions from the facility to no more than 10,368 tons per year. In addition, short term emissions are addressed in the permit, as seen in Table 13.4 above.

According to ADEQ's *Final Miami Sulfur Dioxide Nonattainment Area State Implementation and Maintenance Plan*, dated June 2002, the process changes and installation of air pollution controls through the years has resulted in an increased overall SO_2 control efficiency at the Miami primary copper smelter. Since the 1970's, the SO_2 control rate has risen from approximately 5% to approximately 75% with the installation of the double contact acid plant in the 1974, to approximately 99% as a result of the activities identified in Table 13.5. Conversely, estimated SO_2 emissions from the facility fell from approximately 175,000 tons per year in the early 1970s, to less than 10,000 tons per year at the current time.

A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) revealed that no emission limitations or air pollution control devices have been approved for copper smelters for sulfur oxides since the installation of the double contact acid plant in 1974. In addition, the only two remaining primary copper smelting operations that use batch converters are in Arizona and are subject to ADEQ's jurisdiction. Since the installation of the double contact acid plant there have been no changes at either the ASARCO Hayden smelter or the FMMI smelter that have triggered Prevention of Significant Deterioration review for sulfur oxides (SO_2). As a result, ADEQ has determined that the most stringent control available to control SO_2 emissions from primary copper smelting operations is the double contact acid plant.

Step 7: Select BART

Based upon ADEQ's review of all of the above, ADEQ concurs with FMMI's conclusion that the installation and operation of the double contact acid plant with the New Source Performance Standard of 650 ppm averaged over a 6-hour period constitutes BART for SO_2.

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XIV. SRP CORONADO GENERATING STATION BART ANALYSIS AND DETERMINATION

A. Process Description

SRP Coronado Generating Station (CGS) is comprised of two coal-fired electric utility steam generating units, specifically Unit 1 and Unit 2. These are dry-turbo-fired boilers with a net rated output of 395 MW and 390 MW respectively. CGS generates electricity by combustion of pulverized coal that heats water in boiler tubes to produce steam. This steam is then used to turn a turbine which is connected on a common shaft to a generator rotor. As the rotor in the generator is turned, it induces an electrical current in the stator windings of the generator, making electricity.

B. Consent Decree

On December 22, 2008, SRP and EPA entered into entered into a Consent Decree which requires the implementation of the following pollution control projects for SO_2 and NO_X at SRP's CGS facility.

- Addition of LNB to Units 1 and 2 to reduce NO_X emissions. Coupled with the burner additions will be modifications to the furnace combustion air system on each Unit (ACC).
- Addition of a Selective Catalytic Reduction (SCR) to Unit 2. The SCR will further reduce NO_X emissions from Unit 2.
- Replacement of the existing Pullman Kellog wet limestone Flue Gas Desulfurization systems on Unit 1 and Unit 2 with new wet limestone FGD (WFGD) systems to further reduce SO_2 emissions.

The implementation schedule as laid out in the Consent Decree is as follows:.

Table 14.1 – Implementation Summary of Pollution Control Projects

Unit	Projected Operational Date	Expected Emission Rates
1 or 2	ACC – June 1, 2009	NO_X - 0.320 lb / MMBtu
2 or 1	ACC – June 1, 2011	NO_X - 0.320 lb / MMBtu
2	SCR – June 1, 2014	NO_X - 0.080 lb / MMBtu
2	FGD – January 1, 2012	SO_2 – 95% control or 0.080 lb / MMBtu
1	FGD – January 1, 2013	SO_2 – 95% control or 0.080 lb / MMBtu

C. Description of Emissions Units Subject to Best Available Retrofit Technology (BART)

The BART– affected emission units at the CGS are Units 1 and 2. These units are BART- eligible since they meet the following requirements:

1. They were "in existence" between 1962 and 1977. Units 1 and 2 were in the construction phase in this period.
2. The emissions from the combined BART-eligible units are greater than 250 tons/year. Emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and particulate matter below 10 micron size (PM_{10}) are 29,384, 20,361, and 1,008 tons per year respectively.

3. These units belong to one of the 26 categories of sources identified in the Regional Haze Rule.

Further in order to confirm that the CGS has visibility impacts on the Class I areas, CALPUFF modeling was conducted by SRP to assess impacts at 17 Class I areas. Modeling was conducted with three years of CALMET meteorological data (2001-2003). The results of the baseline CALPUFF modeling are listed in Table 2. This table provides the 8th highest delta-deciview and the total 8th highest deciview (Source contribution plus the natural background).

As demonstrated in Table 2, the impact of CGS on the visibility in Class I areas is more than 0.5 dv threshold that is used as a trigger for BART applicability. Therefore, Units 1 and 2 at CGS are presumed to cause or contribute to visibility impairment and are, therefore, subject-to-BART for SO_2, $NO_{X,}$ and PM_{10}.

Table 14.2 – Regional Haze Impacts Due to Baseline Emissions								
Class I Area	**Ave. Annual Natural Background**	**Met Year 2001**		**Met Year 2002**		**Met Year 2003**		**Average Highest Total Δdv**
		8th Highest Δdv	**8th Highest Total Δdv**	**8th Highest Δdv**	**8th Highest Total Δdv**	**8th Highest Δdv**	**8th Highest Total Δdv**	
Bandalier, NM	4.46	1.0	5.4	1.1	5.5	1.0	5.5	5.46
Bosque del Apache	4.41	1.5	5.9	1.7	6.1	1.5	5.9	5.96
Chiricahua, NM	4.36	0.8	5.2	0.6	5.0	1.1	5.5	5.23
Chiricahua, W	4.35	0.7	5.1	0.6	5.0	1.2	5.6	5.23
Galiuro W	4.32	1.0	5.3	0.8	5.1	0.9	5.2	5.2
Gila W	4.39	2.0	6.4	2.0	6.4	2.3	6.7	6.5
Grand Canyon NP	4.39	1.1	5.5	0.8	5.2	0.5	4.9	5.2
Mazatzal W	4.35	0.9	5.2	1.0	5.4	1.4	5.8	5.45
Mesa Verde NP	4.53	1.1	5.6	1.1	5.6	1.2	5.7	5.63
Mount Baldy W	4.39	1.6	6.0	1.4	5.8	2.0	6.4	6.1
Petrified Forest NP	4.41	2.5	6.9	2.8	7.2	2.7	7.1	7.1
San Pedro Parks W	4.47	0.9	5.4	1.3	5.8	1.3	5.7	5.6
Sierra Ancha W	4.36	1.0	5.3	1.3	5.6	1.7	6.0	5.6
Superstition W	4.32	1.1	5.4	1.0	5.3	1.4	5.7	5.5
Pine Mountain W	4.36	0.5	4.8	0.7	5.1	1.0	5.3	5.1
Saguaro W & NP	4.28	0.8	5.1	0.6	4.9	0.7	4.9	5.0
Sycamore Canyon W	4.40	0.8	5.2	0.7	5.1	0.8	5.2	5.2

Notes:
W: Wilderness Area; NP: National Park; NM: National Monument

D. BART for NO_X

Step 1: Identify the Existing Control Technologies in Use at the Source

NO_X emissions from both Units 1 and 2 are currently controlled by good combustion practices and overfire air. The resulting emission rate ranges from 0.45 to 0.50 lbs/MMBtu.

Step 2: Identify All Available Retrofit Control Options

The alternative NO_X control technologies for limiting NO_X emissions from Unit 1 and Unit 2 are listed as follows:

- Advanced Combustion Control-Low NO_X burners (LNB) and over fire air (OFA)
- Selective non-catalytic reduction (SNCR)
- Selective catalytic reduction (SCR)

The brief evaluation of the above control technologies is provided below:

Advanced Combustion Control (ACC). ACC, including LNB and OFA, on a dry-turbo-fired boilers are designed to control fuel and air mixing to reduce peak flame temperatures resulting in less NO_X formation. Combustion reduction and burnout are achieved in three stages within a conventional low NO_X burner. In the initial stage, combustion occurs in a fuel rich, oxygen deficient zone where the NO_X is formed. In the second stage, the exhaust gases from Stage 1 are exposed to a reducing atmosphere where hydrocarbons that react with the already formed NO_X are formed. In the third stage, internal air staging completes the combustion, but may result in additional NO_X formation. This, however, can be minimized by completing the combustion in an air lean environment. Combustion air is separated into primary and secondary flow sections to achieve complete burnout and to encourage the formation of nitrogen, rather than NO_X. Primary air (70-90%) is mixed with the fuel producing a relatively low temperature, oxygen deficient, fuel-rich zone thereby reducing the formation of fuel-bound NO_X. Secondary air representing 10-30% of the combustion air is injected above the combustion zone through a special wind-box with air introducing ports and/or nozzles mounted above the burners. Combustion is completed at this increased flame volume. This process limits the production of thermal NO_X.

Selective Non-Catalytic Reduction (SNCR). SNCR is based on a gas-phase homogeneous reaction that involves the injection of an-amine based compound into the fuel at an appropriate temperature range for reduction of NO_X. An amine-based compound such as ammonia (NH_3) or urea ($(NH_2)_2$ CO) is used as the NO_X reducing agent. When ammonia or urea is injected into the flue gas stream, it selectively reduces the NO_X into molecular nitrogen and water. At stoichiometric conditions, when the adequate residence time is reached, the overall reactions that occur may be characterized by:

Ammonia

$$4\ NO + 4\ NH_3 \rightarrow 4\ N_2 + 6\ H_2O$$

$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

Urea

$$2\ (NH_2)_2\ CO + 4\ NO + O_2 \rightarrow 4\ N_2 + 2\ CO_2 + 4\ H_2O$$

In an SNCR system, NO_X reduction does not take place in the presence of a catalyst, but rather is driven by the thermal decomposition of ammonia and urea and the subsequent reduction of NO_X. Consequently, the SNCR process operates at higher temperatures than the SCR process. The temperature of the flue gas is critical to the successful reduction of NO_X with SNCR at the point where the reagent is injected. For the ammonia injection process, the necessary temperature range is 1700 to 1900°F. The other factors affecting the performance of SNCR performance are gas mixing, residence time at operating temperatures, and ammonia slip. Since ammonia is present in the flue gas, a portion of the ammonia may oxidize at temperatures greater than 2000°F. Above 2000°F, the reaction of ammonia oxidation becomes predominant. Nitrogen monoxide is formed as a product of the reaction. Thus, when the flue gas temperature at reagent injection locations is higher than the appropriate temperature window, the SNCR process results in increased NO_X formation rather than NO_X reduction. At temperatures lower than the required temperature window, the NO_X reduction rates becomes lower, and unreacted ammonia may slip through and be emitted to the atmosphere.

Selective Catalytic Reduction (SCR). SCR is a process that involves post-combustion removal of NO_X from the flue gas utilizing a catalytic reactor. In the SCR process, ammonia injected into the flue gas reacts with the NO_X and oxygen to form Nitrogen and water by the following general reactions:

$$4\ NO + 4\ NH_3 \rightarrow 4\ N_2 + 6\ H_2O$$

$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

These reactions take place on the surface of the catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_X decomposition reaction to about 375 to 750°F, depending on the specific catalyst and other contaminants in the flue gas. The factors affecting SCR performance are catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst deactivation due to aging or poisoning, ammonia slip emissions, and design of the ammonia injection system.

The SCR system is comprised of a number of subsystems, including the SCR reactor, ammonia injection system, and ammonia storage and delivery system. The SCR reactor would be located downstream of the economizer and ESP, and upstream of the air pre-heater. From the ESP outlet, the flue gas would first pass through a low-pressure ammonia/air injection grid designed to provide optimal mixing of ammonia with flue gas. The ammonia treated flue gas would then flow through the catalyst bed and exit to the air pre-heater. The SCR system for a pulverized coal boiler typically uses a fixed bed catalyst in a vertical down-flow, multi-stage reactor.

Reduction catalysts are divided into two groups: base metal, primary vanadium, platinum, or titanium (lower temperature) and zeolite (higher temperature). Both groups exhibit advantages and disadvantages in terms of operating temperature, ammonia- NO_X ratio, and optimum oxygen concentration. The optimum operating temperature for a vanadium-titanium catalyst system is in the range of 550° to 800°F, which is significantly higher than the optimum operating temperature for the platinum catalyst systems. The vanadium-titanium catalyst begins to break down, however, when continuously operating at temperatures above this range. Operation above the maximum temperature results in oxidation of ammonia to either ammonium sulfate or NO_X, thereby actually increasing the NO_X emissions.

To achieve high NO_X control efficiencies, the SCR vendor suggests a higher ammonia injection rate than is stoichiometrically required to react all of NO_X in the combustion gases. This results in emissions of un-reacted ammonia or "ammonia slip". The various SCR vendors typically guarantee ammonia slip of about 2 ppm for systems designed for very high NO_X performance levels. This excess ammonia may react with SO_3 and water to form ammonium bisulfate $(NH_4)\ HSO_4$ and ammonium sulfate, $(NH_4)_2\ SO_4$. Higher levels of ammonia and SO_2 results in formation of higher levels of these salts. These ammonium

salts may condense as the flue gases cool and can lead to increased emissions of both PM_{10} and $PM_{2.5}$. Furthermore the catalyst promotes the partial oxidation of SO_2 to SO_3, which in turn combines with water thereby increasing the formation of these ammonia salts and potential emissions of PM_{10} and $PM_{2.5}$.

Some SCR installations have experienced significant air pre-heater plugging and corrosion resulting from the deposition of ammonium bisulfate. The plugging and corrosion can cause reduced boiler efficiency, higher flue gas pressure drop, more frequent air pre-heater cleaning and washing, increased boiler downtime, and increased maintenance cost. The primary factors for controlling the formation and deposition of ammonium bisulfate are the levels of ammonia, the level of SO_3, the air pre-heater surface temperature profile, the air pre-heater surface material, and the air pre heater physical configuration. The temperature window for ammonium bisulfate formation is as wide as 300^o to 425^oF.

The SCR system is subject to catalyst deactivation over time. Catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation usually results from either prolonged exposure to excessive temperatures or masking of the catalyst due to entrainment of particulate from ambient air or air contaminants. Chemical poisoning is caused by the irreversible reaction of the catalyst with a contaminant in the gas stream and thus a permanent condition. Catalyst suppliers typically guarantee a limited lifetime for high performance catalyst systems. Fly ash plugging generally results from excessive carryover to the catalyst or poor catalyst gas flow design.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the above control technologies are feasible options for BART at CGS.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

The alternative NO_X control technologies, ACC, SNCR, and SCR, have been successfully applied to new utility coal fired boilers, as well as retrofitted to existing coal fired boilers. The effectiveness of these technologies in reducing NO_X emissions is dependent primarily on the inlet NO_X concentrations, residence time, and operating temperatures. ACC has been demonstrated to achieve 25% to 35% reduction in uncontrolled NO_X emissions. SNCR has been demonstrated to achieve NO_X control efficiencies ranging from 30% to 50% with inlet NO_X concentration of 300 to 400 ppmvd. If staged combustion is used to reduce inlet NO_X concentrations to less than 250 ppmvd, SNCR is capable of achieving NO_X control efficiencies of only 20% to 40%. Likewise, SCR can achieve NO_X control efficiencies as high as 90% with inlet concentrations in the range of 300 to 400 ppmvd. If inlet NO_X concentrations are less than 250 ppmvd, SCR can achieve NO_X control efficiencies ranging from 70% to 80%.

In its BART analysis, CGS considered the above technologies for control of NO_X in the following sequence: ACC in both Unit 1 and Unit 2, ACC with SNCR in both Unit 1 and Unit 2, ACC in both Unit 1 and Unit 2 with SCR in Unit 2, and ACC and SCR in both Unit 1 and Unit 2. Based on the information provided by the equipment vendors, the controls listed above were estimated to reduce NO_X emissions as demonstrated in Table 14.3.

Table 14.3 – NO_X Emission Factors resulting from NO_X Controls			
Control Option	Control Technology	Unit 1	Unit 2
		Pounds/MMBtu	
	Baseline	0.433	0.466
3	ACC- Both Units	0.32	0.32
4a	ACC and SNCR- Both Units	0.224	0.224
4 b	ACC (Both Units) and SCR on Unit 2	0.32	0.08
5	ACC and SCR on both Units	0.08	0.08

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

Costs of Compliance

Based on the vendor data on the capital cost and operation & maintenance cost for different control options, Table 14.4 provides the information on the annual costs associated with each of the control options.

Table 14.4 – Total Capital and Annual Costs associated with NO_X Controls					
Control Option	Control Technology	Total Capital (Million $)	Fixed Capital (Million $)	Annual O&M (Million $)	Total Annual Cost (Million $)
3	ACC- Both Units	$13.00	$1.227	0	$1.227
4a	ACC and SNCR- Both Units	$26.00	$2.454	$2.200	$4.654
4 b	ACC (Both Units) and SCR on Unit 2	$79.00	$7.4570	$1.100	$8.557
5	ACC and SCR on both Units	$145.0	$13.69	$3.400	$17.09

* Fixed capital cost calculation is based on a CRF of 0.09439, assuming an interest rate of 7%, and amortization period of 20 years.

Table 14.5 provides annual estimated emission numbers for NO_X and cost figures relating to the implementation of various control options for NO_X.

Table 14.5: Total Annual Emissions of NO_X with different options of NO_X Controls					
Factor	Baseline	Option 3	Option 4a	Option 4b	Option 5
Unit 1	10,332 tpy	7,636 tpy	5,345 tpy	7,636 tpy	1,909 tpy
Unit 2	10,029 tpy	6,887 tpy	4,821 tpy	1,722 tpy	1,722 tpy
Total (Both Units)	20,361 tpy	14,523 tpy	10,166 tpy	9,358 tpy	3,631 tpy
Reduction from Baseline	-	5,838 tpy	10,195 tpy	11,003 tpy	16,730 tpy
Incremental Reduction from earlier option	-	5,838 tpy	4,357 tpy	808 tpy	5,727 tpy

Table 14.5: Total Annual Emissions of NO_X with different options of NO_X Controls					
Factor	**Baseline**	**Option 3**	**Option 4a**	**Option 4b**	**Option 5**
Annualized Cost (Million $)	-	$1.227	$4.654	$8.556	$17.09
Cost of reduction (Dollar per ton)	-	$210	$457	$778	$1,021
Incremental cost of reduction (Dollar per ton)	-	$210	$787	$4,830	$1,489

Energy Impacts

SCR will consume significantly more energy as compared to the energy consumption in SNCR. This is due to the power required for the increased fan static pressure required to overcome the pressure drop across the catalyst bed, as well as for pumps and evaporator blower. Assuming a pressure drop of 14 inches of water across the catalyst bed, SCR applied to both units will consume 7,300 kWh more electrical power per year than SNCR (approaching 1% of the total power generation of the CGS).

Non-Air Quality Environmental Impacts

One of the most significant impacts of retrofitting SCR and SNCR is the addition of ammonia and urea storage and handling systems. Anhydrous ammonia and aqueous ammonia above 20% are considered dangerous to human health. An accidental release of anhydrous ammonia or 20% or greater aqueous ammonia is reportable to local, state, and federal agencies. In anticipation of such an incident, the site will need to develop, implement, and maintain a Risk Management Plan (RMP) and Process Safety Measures (PSM) Program.

Ammonia associated with fly ash has the potential to present several problems with the disposal and/or the use of fly ash. Once the fly ash is exposed to the SNCR process, there will be a significant quantity of soluble salts associated with fly ash. These salts are expected to be $(NH_4)HSO_4$ and $(NH_4)_2SO_4$.

Dry disposal of ash can cause the leachate and/or runoff water to contain increased concentrations of ammonia. If and when these salts are contacted with water, they will most likely be dissolved and the resulting aqueous concentration of nitrogen-containing compounds can increase in the waters associated with the ash. Table 10 below summarizes the non-air quality environmental impacts associated with the proposed BART control options.

Table 14.6 – Summary of Non-Air Quality Environmental Impacts	
Control Option	**Summary of Non-Air Quality Environmental Impacts**
ACC	- Potential to increase in loss of ignition (LOI) of flyash, which could reduce recycling sales. - Slight increase in CO_2 emissions/kWH associated with reduced boiler efficiency. - Potential for incomplete combustion (lost energy). - Potential for increased corrosion and more frequent replacement of furnace water tubes.

Table 14.6 – Summary of Non-Air Quality Environmental Impacts	
Control Option	**Summary of Non-Air Quality Environmental Impacts**
SNCR	- Addition of ammonia or urea storage and handling systems. - Anhydrous ammonia and aqueous ammonia above 20% are considered dangerous to human health and accidental releases are reportable to local, state, and federal agencies. - The facility must develop, implement, and maintain a Risk Management Plan (RMP) and Process Safety Measures Program (PSM). - Sulfuric acid in the flue gas can cause various power plant operation and maintenance problems. Condensation of sulfuric acid has a significant detrimental effect on downstream equipment, including fouling and corrosion of heat transfer surfaces in the air pre heater. - Ammonia associated with flyash has the potential to present several problems with the disposal and/or use of flyash. - Dry disposal of flyash can cause leachate and/or runoff water to contain increased concentrations of ammonia and/or nitrogen-containing compounds.
SCR	- Addition of Ammonia handling system. - Anhydrous ammonia and aqueous ammonia above 20% are considered dangerous to human health and accidental releases are reportable to local, state, and federal agencies. - The facility must develop, implement, and maintain a Risk Management Plan (RMP) and Process Safely Measures Program (PSM). - Disposal of spent catalyst containing heavy metals such as vanadium, tungsten, or molybdenum. - Increase in CO_2 emissions from power required for the increased fan static pressure required to overcome the pressure drop across the catalyst bed, as well as for pumps and evaporator blower.

Step 6: Evaluate Visibility Impacts

Four different scenarios for control of NO_x emissions were modeled for each meteorological year (2001-2003) and for all 17 Class I areas within 300 km. Brief details of the modeling results are as under:

Option 3: WFGD with ACC. The modeling result indicates that this control option provides an improvement in visibility index by approximately 0.11dv.

Option 4a: WFGD with ACC and SNCR on both units. The modeling result indicates that this control option provides an improvement in visibility index by approximately 0.19 dv.

Option 4b: WFGD with ACC on both units and SCR on Unit 2. The modeling result indicates that this control option provides an improvement in visibility index by approximately 0.22 dv.

Option 5: WFGD with ACC and SCR on both units. The modeling result indicates that this control option provides an improvement in visibility index by approximately 0.34 dv.

Table 12.7 below provides information on the cost in dollars per deciview improvement in visibility achieved by implementing the respective control options. The table also presents details on the incremental cost in dollars per deciview improvement over different control options.

Table 12.7 – Summary for NO_X BART					
Factor	**Option 2 Baseline, WFGD**	**Option 3 ACC**	**Option 4a ACC w/ SNCR**	**Option 4b ACC w/ SCR for Unit 2**	**Option 5 ACC w/ SCR**
Reduction in Emission (tpy)	-	5,838	10,195	11,003	16,730
Annualized Cost (Million $)	-	$1.227	$4.654	$8.557	$17.09
Visibility Index Improvement Over Baseline (Δ dv)	-	0.11	0.19	0.22	0.34
Incremental Cost Effectiveness (Million $/dv)	-	$11.15	$24.50	$38.89	$50.25

Step 7: Select BART

After reviewing the BART analysis provided by the company, and based upon the information above, ADEQ has determined that BART control at CGS for NO_x is ACC (Low NO_x burners with OFA) with an associated NO_x emission rate of 0.32 lbs/MMBtu on 30-day rolling average basis.

E. PM_{10} BART

Step 1: Identify the Existing Control Technologies in Use at the Source

PM_{10} emissions from the facility are currently controlled through the use of a hot-side ESP.

Steps 2-6: Streamlined Review

SRP's BART analysis for PM_{10} was limited to a statement that the current emission levels associated with the existing controls at the Coronado Generating Station range from 0.01 to 0.03 lb/MMBtu. As noted in Section X, PM_{10} BART for similar emissions units with similar emissions controls was determined to be 0.03 lb/MMBtu. Since SRP's CGS is already meeting or exceeding the stringency of the emissions limitation, further analysis was determined to be unnecessary.

Step 7: Select BART

After reviewing the analysis provided by SRP, and the information presented above, ADEQ has determined that BART for PM_{10} from Units 1 and 2 is no further control, and an emissions limitation of 0.03 lb/MMBtu. The PM_{10} emissions will be measured by conducting EPA Method 201/202 tests.

F. SO_2 BART

Step 1: Identify the Existing Control Technologies in Use at the Source

SO_2 emissions are currently controlled with the use of low-sulfur coal and partial wet flue gas desulfurization. The resulting emission rate ranges from 0.6 to 0.7 lbs/MMBtu.

Step 2: Identify All Available Retrofit Control Options

Following control options are available for control of SO_2.

- Wet Flue Gas Desulfurization
- Spray Dryer Absorber
- Dry Sorbent Injection

A brief evaluation of the above control technologies is provided below:

Wet Flue Gas Desulfurization (WFGD). This control option uses limestone or lime to react with SO_2 in the flue gas. The temperature of the flue gas is reduced to its adiabatic saturation temperature and the SO_2 is removed from the flue gas by reaction with the alkaline medium. SO_2 and other acid gases are absorbed into the scrubbing slurry, which falls into the lower section of the reaction tank. Finely ground limestone and make-up water are added to the reaction tank to neutralize and regenerate the scrubbing slurry.

Limestone scrubbing introduces limestone slurry into the scrubber. The SO_2 is absorbed, neutralized, and partly oxidized to calcium sulfite and calcium sulfate in line with the following reaction:

$$CaCO_3 + SO_2 + \tfrac{1}{2}\, H_2O \rightarrow CaSO_3 \bullet H_2O + CO_2$$

$$CaSO_3 \cdot H_2O + 1\tfrac{1}{2}\, H_2O + \tfrac{1}{2}\, O_2 \rightarrow CaSO_4 \bullet 2H_2O$$

Lime scrubbing is similar to limestone scrubbing in equipment and process flow, except that lime is a more reactive reagent than limestone. The reactions for lime scrubbing are as follows:

$$Ca(OH)_2 + SO_2 \rightarrow CaSO_3 \bullet \tfrac{1}{2}H_2O + \tfrac{1}{2}H_2O$$

$$Ca(OH)_2 + SO_2 + \tfrac{1}{2}O_2 + H_2O \rightarrow CaSO_4 \bullet 2H_2O$$

If lime or limestone is used as the reagent for SO_2 removal, additional equipment is needed to prepare the lime/limestone slurry and collecting and dewatering the resultant sludge. Calcium sulfite sludge is difficult to mechanically dewater and is typically stabilized with fly ash for landfilling. Calcium sulfate is stable and is easily dewatered through mechanical processes. To produce calcium sulfate, an air injection blower is needed to supply oxygen for the second reaction to occur (forced oxidation).

Dry Sorbent Injection (DSI). In DSI systems, a dry powdered alkaline material is injected into the hot gas stream to neutralize the acidic species like SO_2, and the resulting solid salts and remaining excess alkaline material is collected by a downstream particulate capture device. Various alkaline materials, both chemically processed and naturally occurring, have seen application in dry scrubbing. Dry hydrated lime, a calcium based alkaline sorbent, is in wide use in dry scrubbing.

Spray Dryer Absorber (SDA). The process consists of the SDA module, a down-stream fabric filter, a reagent preparation system and a product handling system. Hot, untreated flue gas is introduced into a spray dryer absorption chamber contacts a fine spray of reagent slurry. A significant part of the SO_2 in the flue gas is rapidly absorbed into the alkaline droplets. The control of gas distribution, slurry flow rate, and droplet size ensure that the droplets are dried to a fine powder before they touch the chamber walls of the spray dryer absorber.

A portion of the dry product, consisting of fly ash and reaction product, drops to the bottom of the absorption chamber and is discharged. The treated flue gas flows to a particle separator, where the remaining suspended solids are removed. Outlet gasses from the particulate separator pass on to the stack by means of an induced draft fan.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the referenced control technologies are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

SRP and EPA's consent decree stipulates the installation of WFGDs for both the units. WFGD is the most effective control technology available for controlling SO_2 emissions. Since SRP is committing to the WFGD technology, other control technologies are not evaluated from this point forward in the BART analysis.

Table 12.8 – Annual SO_2 Emissions resulting from SO_2 Controls

Control Option	Control Technology	Unit 1	Unit 2
		Pounds/MMBtu	
1	Baseline-Partial FGD	0.610	0.689
2	Wet FGD	0.08	0.08

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

Costs of Compliance

Based on the vendor data on the capital cost and operation & maintenance cost for different control options, Table 9 provides the information on the annual costs associated with each of the control options.

Table 12.9 – Total Capital and Annual Costs associated with SO_2 Controls

Control Option	Control Technology	Total Capital Cost	Fixed Capital Cost	Annual O&M	Total Annualized Cost
1	Baseline- Partial FGD	--	--	--	--
2	WFGD	$347,000,000	$32,753,330	$11,600,000	$44,353,330

* Fixed capital cost calculation is based on a Capital Recovery Factor (CRF) of 0.09439, assuming an interest rate of 7%, and amortization period of 20 years.

Table 12.10 provides annual estimated emission numbers for SO_2 and cost figures relating to the implementation of WFGDs.

Table 12.10 – Total Annual Emissions of SO_2 and cost of reduction with WFGD		
	Baseline, Option 1	**Option 2, WFGD**
Unit 1	14,556 tpy	1,909 tpy
Unit 2	14,828 tpy	1,722 tpy
Total (Both Units)	29,384 tpy	3,631 tpy
Reduction from Baseline	-	25,753 tpy
Annualized Cost	-	$ 44,353,330
Cost of reduction ($ per ton)	-	$1,722

Step 6: Evaluate Visibility Impacts

The new WFGD control scenario was modeled for each meteorological year (2001-2003) and for all 17 Class I areas within 300 km. The modeling result indicates that the installation of a WFGD will provide for significant visibility benefit. The highest visibility improvement will occur at the Petrified National Forest where an improvement of 1.38 Δdv is expected.

Table 12.11 provides information on annualized cost and the cost in dollars per deciview average improvement in visibility achieved by implementing the control option.

Table 12.11 – Summary for SO_2 BART		
	Option 1, Baseline	**Option 2, WFGD**
Reduction in Emission (tpy)	-	25,753
Annualized Cost	-	$44,353,330
Visibility index (dv)	2.66	1.28
Improvement in Visibility Index (dv)	-	1.38
Incremental Cost Effectiveness ($ per dv)	-	$32,140,094

Step 7: Select BART

Based on its review of the company's analysis and the information above, the Department accepts SRP's recommended BART control of WFGDs for both units with an associated SO_2 emission rate of 0.08 lbs/MMBtu on 30-day rolling average basis.