



**TECHNICAL REVIEW AND EVALUATION
OF APPLICATION FOR
AIR QUALITY SIGNIFICANT REVISION NO. 63088
TO OPERATING PERMIT NO. 64169**

Salt River Project Agricultural Improvement and Power District – Coronado Generating Station

I. INTRODUCTION

This Significant Permit Revision No. 63088 to Operating Permit No. 64169 is issued to the Salt River Project (SRP) – Coronado Generating Station (CGS). CGS consists of two coal-fired electric generating units, Units 1 and 2, which are subject to the Best Available Retrofit Technology (BART) requirements of the Clean Air Act. The Arizona Department of Environmental Quality (ADEQ) is approving an alternative to NO_x BART requirements (“BART Alternative”) established by the Environmental Protection Agency (EPA) as a revision to the Regional Haze Program State Implementation Plan (SIP). This Significant Permit Revision incorporates two BART Alternative operating strategies (OS) into Operating Permit No. 52639.

- Operating Strategy 1 (OS-1): Install and commence operation of a Selective Catalytic Reduction (SCR) System on Unit 1 by December 31, 2025; or
- Operating Strategy 2 (OS-2): Shut down Unit 1 by December 31, 2025.

For the period starting December 5, 2017, and ending no later than December 31, 2025, both BART Alternative operating strategies will include a Unit 1 interim operating strategy (IS) that will involve three seasonal curtailment options for Unit 1. These options entail varying durations of curtailment of Unit 1 and are dependent on the demonstrated NO_x emissions rate of Unit 1 and the demonstrated SO₂ emissions rates of Unit 1 and Unit 2. In connection with the SIP revision, SRP has conducted visibility modeling to demonstrate that the BART Alternative represents an improvement in visibility in Class I areas over the BART required by the current Regional Haze SIP and 2016 EPA BART Reconsideration.¹

In addition, this Significant Permit Revision constitutes a Prevention of Significant Deterioration construction permit for the installation of a SCR on Unit 1, if BART Alternative OS-1 is selected.

A. Company Information

Facility Name: SRP – Coronado Generating Station
Mailing Address: PO Box 52025, PAB 352, Phoenix, AZ 85072-2025
Facility Location: Six miles northeast of St. Johns off U.S. Highway 191
St. Johns, AZ 85936

¹ 81 FR 21735, April 13, 2016.



B. Attainment Classification

SRP's Coronado Generating Station is located in an area that is designated unclassifiable or attainment for all National Ambient Air Quality Standards (NAAQS) for which final designations have been made.

II. BACKGROUND

On February 28, 2011, the Arizona Department of Environmental Quality (ADEQ) submitted to the Environmental Protection Agency (EPA) the state's initial Regional Haze SIP for the first planning period of the regional haze program. This submission included BART determinations for CGS Unit 1 and Unit 2.

EPA published its notice of final rulemaking approving Arizona's SO₂ and PM₁₀ BART determinations, disapproving Arizona's NO_x BART determinations, and establishing a NO_x BART Federal Implementation Plan (FIP) for Units 1 and 2, the two BART-eligible electric generating units at CGS, on December 5, 2012. The FIP imposed a NO_x emission limit of 0.065 pounds per million British thermal units applicable across both units on a 30-boiler-operating-day average basis, with a final compliance date of December 5, 2017. The rule also required SRP to install a SCR system on Unit 1 by the compliance date of December 5, 2017. Unit 2 is already equipped with SCR (commenced operation in 2014) through a consent decree (CD) between SRP and EPA.

In February 2013, SRP filed with EPA a petition for administrative reconsideration of the NO_x BART determination in the FIP. EPA granted this petition in part and thereafter prepared and proposed a revised NO_x BART FIP, which, after notice-and-comment rulemaking, was published as a final rule in the Federal Register on April 13, 2016. This EPA action revised the NO_x limit for Unit 1 to 0.065 lb/MMBtu and for Unit 2 to 0.080 lb/MMBtu, with both limits to be met on a 30-boiler-operating-day average, and maintained the initial compliance date of December 5, 2017.

EPA released its proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units, commonly referred to as the Clean Power Plan (CPP), in June 2014. EPA published this rule in final form in October 2015. The final rule gave states until September 2018 to submit final plans outlining how they will meet the requirements set forth by EPA in the final CPP. On February 9, 2016, the U.S. Supreme Court granted a stay of the CPP, halting implementation of the CPP pending the resolution of legal challenges to the program in court. This action has created uncertainty for SRP with respect to the nature and timing of its CPP compliance obligations for the CGS units.

III. REVISION DESCRIPTION

Effectiveness of this permit revision is contingent on approval of ADEQ's SIP revision as part of the Regional Haze SIP for Arizona and will be effective on the date of final action by EPA, provided that such final EPA action also revokes or rescinds EPA's FIP (published at 77 FR 72511 on Dec. 5, 2012, and the reconsideration published in the Federal Register on April 13, 2016), insofar as that FIP establishes NO_x, SO₂, and PM₁₀ emission limits or other requirements for the CGS units.

A. Regional Haze Requirements (RHR):

The BART Alternative for CGS Unit 1 consists of two alternative operating strategies. These BART Alternative Operating Strategies comprise an interim operating strategy followed by either installation of SCR on Unit 1 or permanent cessation of operation of Unit 1 (either alternative to be implemented no later than December 31, 2025).



1. BART Alternative Operating Strategy-1 (OS-1): Seasonal Curtailments followed by SCR on Unit 1

This operating strategy comprises of three interim operating strategies (IS) that employs seasonal curtailment periods of Unit 1 followed by installation of a SCR system on Unit 1 no later than December 31, 2025 to achieve a NO_x limit of 0.065 lb/MMBtu on a 30-boiler-operating-day average. These three IS options (IS 2, IS 3, and IS 4) involve a reduction in the SO₂ emission rate at both Unit 1 and Unit 2. One of the interim operating strategies (IS4) also includes a NO_x emission rate below the permit limit for Unit 1. In each option year, the length of the required curtailment period for Unit 1 is dependent on the NO_x emissions rate performance of Unit 1 and on the SO₂ emissions rate performance of both Unit 1 and Unit 2.

2. BART Alternative Operating Strategy-2 (OS-2): Seasonal Curtailments followed by Unit 1 Shutdown No Later than 2025

Under this BART Alternative operating strategy, the IS’s described above (IS2, IS3, and IS4) are followed until permanent cessation of operation of Unit 1, which must occur no later than December 31, 2025.

3. BART-Alternative Implementation Schedule

The BART Alternative will take effect on the compliance date established by EPA’s BART FIP, i.e., December 5, 2017. On this date, SRP will begin compliance with one of the three seasonal curtailment options under the IS based on CGS emissions performance between January 1, 2017 and October 20, 2017. The three curtailment options are listed in Table 1 below.

Table 1: Seasonal Curtailment Options for Unit 1 Interim Operating Strategy

Strategies	Unit 1		Unit 2	Unit 1 Curtailment Period
	(lb/MMBtu) (Highest 30-boiler-operating-day average)			
	NO _x	SO ₂		
IS 2	0.320	0.060	0.060	Oct. 21 to Jan. 31
IS 3	0.320	0.050	0.050	Nov. 21 to Jan. 20
IS 4	0.310	0.060	0.060	Nov. 21 to Jan. 20
IS 2, IS 3, and IS 4	1,970 tons of SO ₂ per year			

Once Arizona has in place a final approved CPP plan, (if CPP takes effect and is implemented), SRP will finalize its choice (no later than December 31, 2022 regardless of CPP status) of BART Alternative Operating Strategy and notify EPA and ADEQ.

- a. OS-1 – Under the first BART Alternative Operating Strategy, SRP will install a SCR system on Unit 1 that achieves a NO_x emission limit at that unit of 0.065 lb/MMBtu on a 30-boiler-operating-day average no later than December 31, 2025. Under this operating strategy, this commitment will provide visibility improvement compared to the BART control strategy,



followed by an indefinite number of years of operation with the same NOx emissions limitations for Unit 1 as the 2016 EPA BART Reconsideration and more stringent SO₂ emissions limitations for both units than those in the existing EPA-approved SIP.

Installation of the SCR system on Unit 1 (“SCR Project” or “Project”) will result in significant increases in emissions of three regulated NSR pollutants: PM₁₀, PM_{2.5}, and sulfuric acid mist (abbreviated herein and in the permit revision as H₂SO₄). Therefore, the SCR Project at Unit 1 is a major modification under prevention of significant deterioration (PSD) and is subject to PSD review for PM₁₀, PM_{2.5}, and H₂SO₄ under A.A.C. R18-2-406. Table 2 below shows the projected increase in emissions from Unit 1.

Table 2: Increase in Emissions Due to SCR System on Unit 1

Pollutant	Baseline Actual Emissions	Projected Actual Emissions	Excluded * Emissions	Project Emissions Increase	Significant Emission Rate
	Tons per year				
NO _x	4,986.8	1,226.6	NA	-3,760.2	40
PM	132.8	169.8	37.1	0.0	25
PM ₁₀	171.4	622.7	364.5	86.8	15
PM _{2.5}	171.4	622.7	364.5	86.8	10
H ₂ SO ₄	6.7	94.4	0.8	86.8	7

* These excluded emissions are the emissions that could have been accommodated from Unit 1.

- b. OS-2 – Under the second BART Alternative Operating Strategy, SRP will permanently shut down Unit 1 no later than December 31, 2025. The interim operating strategy will be required until the date Unit 1 shuts down.

B. Best Available Control Technology (BACT) Analysis for SCR Project under OS-1

This section presents a summary of the methodology used and the results obtained while determining BACT for PM₁₀, PM_{2.5}, and H₂SO₄ emissions resulting from the Unit 1 SCR Project. The BACT determinations are supported by a complete BACT analysis contained in Appendix “F” of the permit application. As summarized below, the Department agrees with the analysis performed and the conclusions reached by SRP.

As discussed in Section III.C herein, in the event that the construction of the SCR does not commence within 3 years of issuance of this permit revision, SRP shall submit a significant revision application containing an updated BACT analysis at least 18 months but no more than 24 months prior to the expected start of construction of the SCR system that demonstrates that the emission limits still represent BACT for PM₁₀, PM_{2.5}, and H₂SO₄.

General

“Best available control technology” (BACT) means an emission limitation, including a visible emissions standard, based on the maximum degree of reduction for each regulated New Source Review (NSR) air pollutant that would be emitted from any proposed major



source or major modification, taking into account energy, environmental, and economic impact and other costs, determined by the Director in accordance with R18-2-406(A)(4) to be achievable for such source or modification.

The Department generally uses a “top-down” procedure when making BACT determinations. This procedure is designed to ensure that each determination is made consistent with the two core criteria for BACT: consideration of the most stringent control technologies available, and a reasoned justification, considering energy, environmental and economic impacts and other costs, of any decision to require less than the maximum degree of reduction in emissions. The framework for the top-down BACT analysis procedure used by the Department comprises five key steps as follows:

- Identify all control options;
- Eliminate technically infeasible control options;
- Characterize control effectiveness of technically feasible control options;
- Evaluate more effective control options; and
- Select BACT.

1. H₂SO₄ BACT Analysis

The majority of the fuel sulfur combusted in a coal-fired boiler leaves the boiler as sulfur dioxide (SO₂). During combustion, a small percentage of the fuel sulfur is further oxidized to sulfur trioxide (SO₃). The oxidation of SO₂ to SO₃ will increase when the SCR catalyst is used for NO_x control.

A fraction of the SO₃ in the flue gas stream reacts with water vapor to form sulfuric acid (H₂SO₄). The flue gas temperature decreases as it passes through the air heater and pollution control systems. When the flue gas temperature drops below the acid dew point, a fraction of the gaseous H₂SO₄ condenses into an aerosol. Thus, the resulting emissions include three related constituents: gaseous SO₃, gaseous H₂SO₄, and aerosol H₂SO₄. The total emissions rate for the regulated NSR pollutant named “sulfuric acid mist” is the sum of the emissions rates for these three constituents, reported as H₂SO₄.

Guidance documents and technical papers regarding H₂SO₄ emissions from coal-fired electric generating units have H₂SO₄ emission concentrations covering a wide range from 0.03 to 14 parts per million volume (ppmv) at 3% oxygen. For example, an EPA document recommends using a H₂SO₄ emission concentration of 3 to 7 ppmv for coal with a sulfur content of 0.5% or less, and a concentration of 14 ppmv for coal with a sulfur content of 1.0%. EPA’s AP-42 document states that about 0.7% of fuel sulfur is emitted as SO₃. For CGS Unit 1, a coal sulfur content of 1.6 pounds of SO₂ per million Btu (lb SO₂/MMBtu) would result in an H₂SO₄ emission rate of 0.017 lb/MMBtu or 6 ppm.

There are other factors that affect the H₂SO₄ emission rate exiting the stack. Factors that can increase emissions of H₂SO₄ include SCR and flue gas conditioning using SO₃. Factors reducing emissions of H₂SO₄ include particulate matter removal devices, air heater deposition, reagent injection, flue gas conditioning using ammonia, ammonia slip from the SCR, coal ash alkalinity, and FGD systems. CGS Unit 1 currently burns approximately 60 to 100% Powder River Basin (PRB) coal with a highly alkaline fly ash and a hot-side electrostatic precipitator (ESP),



conventional air heater, and wet flue gas desulfurization (WFGD) system. The Project under consideration would add an SCR system to the unit which would increase H_2SO_4 emissions. With the addition of the SCR system, it is estimated that the post-SCR H_2SO_4 emission rates would range from 0.003 to 0.019 lb/MMBtu, depending on the formation of SO_3 by the boiler for various coals, an SCR SO_2 -to- SO_3 conversion rate of 0.5%, and the reductions afforded by the hot-side ESP, air heater, and WFGD system.

a. Step 1: Identify all potential control technologies

Until about ten years ago, the only control options identified in the RACT/BACT/LAER Clearinghouse (RBLC) database for the control of H_2SO_4 from coal-fired boilers were the controls used for controlling particulate matter and SO_2 . These included WFGD or dry flue gas desulfurization (DFGD) systems, and ESPs or fabric filters (FF) used for PM control. H_2SO_4 is controlled in both WFGD and DFGD systems through mechanisms similar to SO_2 control. H_2SO_4 also tends to adsorb onto fly ash particles as the flue gas cools and is collected by the PM controls.

In the last ten years, several new pulverized coal (PC) units burning moderate to high sulfur coals were permitted with the use of wet electrostatic precipitators (WESP) and reagent injection systems for H_2SO_4 control. Reagent injection systems for H_2SO_4 control identified in RBLC database include: sorbent injection (SI), spray dryer absorber (SDA), and hydrated lime injection (HLI). These systems use lime as the sorbent.

Another technology identified in RBLC database for the control of H_2SO_4 is the use of ultra-low activity (ULA) SCR. Catalysts used in SCR systems can be formulated in ways that reduce the oxidation of SO_2 to SO_3 . Oxidation rates for SCR catalysts range from 0.3% to 3%. For example, the CGS Unit 2 SCR catalyst oxidation rate is guaranteed $\leq 0.5\%$. SRP intends to include ULA SCR catalyst as part of the SCR design for CGS Unit 1.

The amount of H_2SO_4 generated is a function of combustion gas SO_2 concentration. H_2SO_4 formation can be reduced by firing lower sulfur content coals. The following control options are potentially applicable for the control of H_2SO_4 emissions:

- Coal switching – burning 100% of very low sulfur coals (i.e., PRB coal);
- Coal washing – reducing coal ash and sulfur content; and
- Coal processing – mixing the coal with chemicals that break the sulfur away from the coal molecules.

The following control technologies can potentially be used to reduce H_2SO_4 emissions in addition to the existing CGS Unit 1 control systems (PRB coal, hot-side ESP, and WFGD):

- Coal Switching, Washing, and Processing



- Flue Gas Conditioning
- Reagent/Sorbent Injection Systems
 - Calcium-based reagent injection
 - Sodium-based reagent injection
 - Hydrated lime injection (HLI)
- Wet Electrostatic Precipitation

b. Step 2: Identify Technically Feasible Control Technologies

As discussed in Step 1, H₂SO₄ emissions can be controlled to varying degrees using PM and FGD control systems and low sulfur coals. CGS Unit 1 is already well controlled for PM, SO₂, and H₂SO₄ by the following systems in place: 60 to 100% PRB coal, hot-side ESP, and WFGD. The use of ultra-low activity SCR catalyst is an inherent part of the proposed Project. Additional H₂SO₄ controls that are potentially applicable include:

- Coal Switching, Washing, and Processing;
- Flue Gas Conditioning;
- Reagent/Sorbent Injection; and
- Wet Electrostatic Precipitation.

The following discussion identifies which of these control options are technically feasible and available.

(1) Coal Switching, Washing, and Processing

Fuel switching to a lower sulfur coal can be one option for reducing emissions of H₂SO₄. CGS Unit 1 currently fires sub-bituminous blends, but has historically used bituminous and sub-bituminous coals, and may continue to do so in the future. Western bituminous coal has sulfur concentrations ranging from 1.0% to 1.5% with a heating value range of 9,200 to 12,000 British thermal unit (Btu) per pound. Sub-bituminous/ PRB coal has sulfur concentrations below 0.5% with a heating value range of 8,000 to 8,600 Btu per pound. Switching to 100% PRB subbituminous coal could potentially reduce boiler SO₃ emissions. Currently, CGS Unit 1 burns 60% to 100% PRB coal. The decision of the type and amount of coal to burn is very complex. The reliability of PRB deliveries is a legitimate and significant concern. In order to minimize potential issues associated with dependable fuel delivery and to ensure economical long-term supply of fuel, CGS must keep the option to use western bituminous coals. Thus switching to 100% PRB subbituminous coal is not considered an available H₂SO₄ control option.

Coal washing, or beneficiation, is one pre-combustion method that has been used to reduce impurities in the coal (i.e., ash and sulfur). In general coal washing is accomplished by separating and removing inorganic impurities from organic coal particles. For economic reasons, coal washing occurs at the mine in order to reduce the cost of shipping the waste rock and to provide a disposal area for the waste rock. To date, no commercial coal



washing plants have been built to wash western coals. Therefore, washing coal as a strategy to reduce H_2SO_4 emissions is not considered an available control option.

(2) Flue Gas Conditioning

Flue gas conditioning refers to the addition of water or chemicals to the flue gas in order to modify properties of fly ash or other particulate matter that improves the collection efficiency of the ESP or WFGD. A conditioning agent may influence the ESP collection efficiency through one or more of the following mechanisms:

- adsorbing on the surface of fly ash to reduce surface resistivity;
- adsorbing on the fly ash to change the adhesion and cohesion properties of the ash;
- increasing ultrafine particle concentrations for space charge enhancement;
- increasing the electrical breakdown strength of the flue gas,
- increasing the mean particle size; and
- changing the acid dew point in the flue gas.

Many chemicals and water have been used as conditioning agents at power plants, most common being SO_3 and ammonia (NH_3). The injection of SO_3 increases the amount of SO_3 in the flue gas and as a result are not technically feasible controls for SO_3 . Humidification adds water upstream of the WFGD to slowly cool the flue gas below its acid dew point and thereby condense large acid droplets. The WFGD more effectively captures larger acid droplets. However, humidification upstream of the WFGD may cause fly ash dropout in the ductwork resulting in corrosion or choking of equipment near the WFGD inlet. This process has not been demonstrated on coal-fired boilers equipped with WFGD. Therefore, humidification is not considered a technically feasible H_2SO_4 control option.

Ammonia and dry alkali injection are discussed in the following subsection.

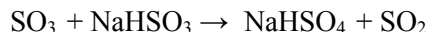
(3) Reagent/ Sorbent Injection

Reagent/sorbent injection systems use chemicals such as ammonia, sodium bisulfite (NaHSO_3) or lime (CaO) to react with SO_3 to form sulfate byproducts. Most of the reagent injection technologies react with SO_3 or H_2SO_4 to form a solid particle which is then collected by downstream particulate control systems or WFGD systems.

One sorbent injection system injects a solution of sodium bisulfite upstream in the flue gas. This reagent reduces SO_3 to SO_2 so that the sulfur dioxide may be collected in the WFGD system. Sulfur



trioxide is removed according to the following general equation:



Reagent injection with NH_3 has achieved SO_3 reductions greater than 90%.

One major factor with the application of some reagent injection technologies is the injection must be before a PM control device. Most coal-fired utility boilers have cold side ESPs or fabric filters. As a result, the injection of reagent will be ahead of the PM control device. However, as is the case with CGS Unit 1, some boilers are equipped with hot-side ESPs. In order to control the H_2SO_4 generated by the installation of the SCR system, the reagent injection would have to be before the WFGD system. As a result, the solid byproducts of the reagent injection system would have to be captured by the CGS Unit 1 WFGD system.

All of the reagent injection technologies increase the amount of PM in the flue gas. Reagent injection technologies that inject a solid reactant (lime, sodium bicarbonate, etc.) increase the PM loading due to the solids injected. Reagent injection technologies that inject a gas or liquid reactant increase the PM loadings due to the reaction product (ammonium sulfates, NaHSO_4 , etc.). These solids are fine particulates, less than $2.5 \mu\text{m}$, and are not easily removed by WFGD systems. Typically, WFGD systems only remove 50% to 60% of PM_{10} .

(4) Wet Electrostatic Precipitators

The principle of operation of a WESP is similar to a dry ESP. Particulate matter in the flue gas is exposed to an electric field which induces a charge on the particle which is then drawn to an oppositely charged collection electrode. However, in a WESP, the flue gas is cooled near or below the dew point and consequently PM may be present as either solid or liquid particles. For large flue gas flow applications, plate type WESPs are most commonly used. Recently membrane-type WESPs have been commercially demonstrated at industrial scale and have been pilot tested on coal/coke-fired boiler flue gas. Each of these types is discussed below.

(a) Conventional WESP

Conventional WESPs have been reported to provide significant control of filterable (solid and liquid) PM. The EPA Air Pollution Control Technology Fact Sheet for conventional WESPs reports filterable $\text{PM}_{2.5}$ control efficiencies of 90.0 to 99.2% for various industrial applications.

(b) Membrane WESP



Membrane WESPs use the same electrostatic principles used in conventional WESPs, but they utilize polypropylene membranes rather than steel plates as collection surfaces. The membrane collectors are made of corrosion-resistant fibers. Capillary action between the fibers maintains an even distribution of water throughout the membrane. In addition to flushing collected particles, the water acts as the charge-carrying electrode. These attributes of membrane WESPs avoid issues with plate-type WESPs such as: field disruptions that occur due to spraying (misting) of water, and formation of dry spots (channeling) that causes collector surface corrosion and reduced collector efficiency.

(c) WESP Performance Summary

WESPs are expected to be effective in controlling H_2SO_4 emissions at saturated flue gas conditions. When used in conjunction with WFGD systems and high sulfur fuels, WESPs are very effective at reducing H_2SO_4 mist. However, WESP systems have only been required for PC fired boilers firing high percentages of medium to high sulfur bituminous coals or petroleum coke and equipped with WFGD systems for SO_2 control. In these medium to high sulfur fuel applications, H_2SO_4 concentrations leaving the WFGD system may be as high as 10 to 40 ppm, or 0.03 to 0.12 lb/MMBtu. WESP control efficiencies when applied to boiler flue gases with high concentrations of H_2SO_4 are on the order of 90%.

While the use of a WESP system is technically feasible for application at CGS Unit 1, there are no WESP demonstrations that indicate the use of WESP on units that fire a significant percentage of subbituminous coal would reduce emissions by a quantifiable amount below the levels which can be achieved without a WESP system. Recent stack testing at CGS Unit 2, which was retrofit with an SCR system in 2014, measured H_2SO_4 emissions as 0.002 lb/MMBtu without the application of any H_2SO_4 controls. This H_2SO_4 level is lower than most of the H_2SO_4 permit limits in the RBLC database.

c. STEP 3. Rank the Technically Feasible Control Technologies

Based on the Step 2 analysis, the following H_2SO_4 controls are considered technically feasible and available: reagent injection and WESP. Based on the RBLC database, permitted operational units with WESPs have a BACT range from 0.005 lb/MMBtu to 0.01 lb/MMBtu for H_2SO_4 emissions and those with reagent injection technologies range from 0.005 lb/MMBtu to 0.027 lb/MMBtu. Currently, CGS Unit 2 has a H_2SO_4 emissions limit of 0.006 lb/MMBtu without any specific H_2SO_4 emission controls. Recent stack testing at CGS Unit 2, which was retrofit with an



SCR system in 2014, measured H₂SO₄ emissions as 0.002 lb/MMBtu. Since CGS Units 1 and 2 are similar (except that Unit 2 is equipped with SCR), it is assumed for baseline purposes that the emissions from CGS Unit 1 will be similar to the CGS Unit 2 permit limit after the installation of SCR on CGS Unit 1. It is assumed that the application of WESP or reagent injection can lower H₂SO₄ emissions to 0.0005 lb/MMBtu (90% reduction).

d. STEP 4. Evaluate the Most Effective Controls

Based on the Step 3 discussion, the maximum achievable emission reduction is based on reducing H₂SO₄ emissions from 0.005 lb/MMBtu (1.7 ppm) down to 0.0005 lb/MMBtu (0.17 ppm) using either a WESP or reagent injection. The following identify the BACT impacts (environmental, economic and energy) of WESP and reagent injection technologies.

(1) Reagent Injection

Pilot scale and full-scale testing and commercial operation have confirmed that up to 90% or greater SO₃ control efficiency is possible with several different sorbents, including ammonia and SBS™. Control efficiency performance with other sorbents is somewhat lower at 70% to 90%. Table 3 provides the environmental, economic, and energy impacts for reducing H₂SO₄ emissions by 70% and 90% using reagent injection technologies. The environmental, economic, and energy impacts are discussed in the following subsections.

Table 3: Summary of H₂SO₄ BACT Impacts for Reagent Injection

Parameter	WFGD Baseline	Reagent Injection at 90% Control	Reagent Injection at 70% Control
Boiler Heat Input, MMBtu/hour (HHV)	4,719		
Flue Gas From FGD, scfm	1,097,387		
Unit Gross Generation, kW	456,000		
Controlled Emission Rate, lb/MMBtu	0.005	0.0005	0.0015
Potential H ₂ SO ₄ Emissions, tons/year	103	10	31
Total Capital Requirement, \$	n/a	\$6,840,000	\$6,840,000
Capital Recovery Factor (CRF)	n/a	0.0944	0.0944
Annual Capital Cost, \$/yr	n/a	\$646,000	\$646,000
Annual O&M Cost, \$/yr	n/a	\$46,000	\$35,000
Total Annual Cost, \$/yr	n/a	\$692,000	\$681,000
Emission Reductions relative to Baseline, tons/year	0	93	72
Average Cost Effectiveness, \$/ton	n/a	\$7,440	\$9,414



(a) Environmental Impacts

The primary environmental impact of reagent injection is the reduction in H_2SO_4 emissions from 0.005 lb/MMBtu to 0.0015 lb/MMBtu for 70% control, and to 0.0005 lb/MMBtu for 90% control. Reagent injection would reduce H_2SO_4 emissions by 72 tons for 70% control and 93 tons for 90% control. On the negative side, with reagent injection systems there will be a small increase in plant solid waste and a potential increase in PM emissions from the WFGD stack.

Additionally, as discussed above, the use of reagent injection systems to control H_2SO_4 emissions will result in an increase in $\text{PM}_{2.5}$. The CGS Unit 1 WFGD may capture 50 to 60% of the $\text{PM}_{2.5}$, with the remainder being emitted from the WFGD stack. This collateral increase in $\text{PM}_{2.5}$ along with the undemonstrated status of reagent injection on boilers firing low-sulfur, alkaline ash coals makes the use of reagent injection systems infeasible as BACT for technical and environmental impact reasons for CGS Unit 1.

(b) Economic Impacts

The addition of a reagent injection system before the WFGD system would have a negative economic impact (Unit is equipped with ESP and WFGD that are considered the baseline for the analysis). The capital costs of retrofitting a reagent injection system before the WFGD system is estimated at \$6.8 million based on an average cost of \$15 per kilowatt. The total annual cost of approximately \$0.68 million per year is based on:

- A capital recovery factor of 0.0944 (20-year life and 7% societal cost of money per U.S. EPA guidance); and
- Annual operating and maintenance cost of \$600 per ton of SO_3 removed.

Table 3 above shows that the incremental cost effectiveness of adding a reagent injection system before the existing WFGD is greater than \$7,400 per ton of H_2SO_4 reduced. This is a high cost of control and is not economically feasible as BACT.

(c) Energy Impacts

The application of a retrofit reagent injection would result in a small increase in power requirements for the injection



system pumps (for liquids injection) or air compressors (for solids injection).

(2) Wet Electrostatic Precipitators

Table 4 below presents the environmental, economic, and energy impacts for reducing H₂SO₄ emissions by 90% using a WESP, and the results are discussed in the following subsections.

Table 4: Summary of H₂SO₄ BACT Impacts for Wet ESP Addition after WFGD System

Parameter	WFGD-Baseline	WFGD Plus WESP
Boiler Heat Input, MMBtu/hour (HHV)	4,719	
Flue Gas From FGD, scfm	939,868	
Unit Gross Generation, kW	456,000	
Controlled Emission Rate, lb/MMBtu	0.005	0.0005
Potential H ₂ SO ₄ Emissions, tons/year	103	10
WESP Total Capital Requirement, \$	n/a	\$29,112,000
Capital Recovery Factor (CRF)	n/a	0.0944
Annual Capital Cost, \$/yr	n/a	\$2,748,000
Annual O&M Cost, \$/yr	n/a	\$5,487,000
Total Annual Cost, \$/yr	n/a	\$8,235,000
Ton Reduced, tons per year	n/a	93
Cost per Incremental Ton Reduced, \$/ton		\$88,500

(a) Environmental Impacts

The primary environmental impact of adding the WESPs after the WFGD is the reduction in total H₂SO₄ emissions from 0.005 to 0.0005 lb/MMBtu assuming a 90% control efficiency. The addition of a WESP would reduce potential H₂SO₄ emissions from 103 tons per year to 10 tons per year, resulting in a reduction in total H₂SO₄ emissions of 93 tons per year. In addition, emissions of PM_{2.5} would be reduced by approximately 80%. On the negative side, an acid waste water stream is generated which will require additional processing before disposal of the wet solids and the waste water stream.

(b) Economic Impacts

The addition of a WESP after the WFGD system would have a significant economic impact (unit is equipped with ESP and WFGD that are considered the baseline for the analysis). The capital costs of retrofitting a WESP on top of the current WFGD system is estimated at \$29.1 million based on a cost of \$26.5 dollars per wet standard cubic feet of flue gas. This equates to \$64 per kilowatt, which is consistent with the costs reported by others for retrofit installations.



The total annual cost of \$8.2 million per year is based on:

- A capital recovery factor of 0.0944 (20-year life and 7% societal cost of money per U.S. EPA guidance), and
- Annual operating and maintenance cost of \$5 per standard cubic feet a minute (scfm) of flue gas.

It can be seen from Table 4 above that the incremental cost effectiveness of adding a WESP to the existing WFGD outlet duct work is greater than \$88,000 per ton of H₂SO₄ reduced. This is a very high cost of control demonstrating that the addition of a WESP is not cost effective as BACT.

(c) Energy Impacts

The primary energy impacts of the WESP technology would be increased electrical demand for operation of the WESP and additional induced draft (ID) fan power requirements for the increase in pressure drop.

e. STEP 5. Proposed Sulfuric Acid Mist BACT Determination

Based on the Step 4 analysis, the application of WESP technology and reagent injection technology are not BACT. Either of these control options would have significant, adverse economic impacts and would provide negligible, beneficial environmental impacts, as reflected in the calculated cost effectiveness values of more than \$88,000 per ton of H₂SO₄ removed and more than \$7,000 per ton of H₂SO₄ removed, respectively. Therefore, ADEQ has determined an emission limit of 0.005 pounds per MMBtu heat input is BACT for H₂SO₄ emissions from CGS Unit 1. Compliance with this limit will be determined using EPA Conditional Test Method 13, based on the average of three test runs of at least two hours each. This limit reflects the use of low-sulfur western coals and ultra-low activity SCR catalyst and continuous performance of the existing boiler, HESP, and WFGD system in accordance with good air pollution control practice.

2. PM₁₀ & PM_{2.5} BACT Analysis

Flue gas emitted from large, coal-fired boilers, such as CGS Unit 1, contains particulate matter. The particulate matter emitted is essentially all less than μm (PM_{2.5}); thus, the PM₁₀ and PM_{2.5} emission rates are identical, and the filterable PM₁₀ and PM_{2.5} emission rates are identical to the filterable PM emission rate. In addition, CGS Unit 1 is equipped with a WFGD system and its exhaust gases are saturated with water. There is no reference method that can be applied to determine whether any fraction of the filterable PM emissions from this unit is made up of PM₁₀ or PM_{2.5}. The EPA test method for PM₁₀ and PM_{2.5} emissions, Reference Method 201A- Paragraph 1.5 of this method states the following:

Limitations. This method cannot be used to measure emissions in which water droplets are present because the size separation of the water droplets may not be representative of the dry particle size released into the air. To measure filterable



PM₁₀ and PM_{2.5} in emissions where water droplets are known to exist, we recommend that use of Method 5 of appendix A-3 to part 60.

As a result, the following discussion will focus on the control of PM_{2.5}, but the resulting emission limit will be expressed as total particulate matter, with the filterable fraction measured using Reference Method 5.

Primary PM_{2.5} Emissions

Primary or “direct” PM_{2.5} emissions from CGS Unit 1 can be broken into two components with distinct physical and chemical properties in the boiler flue gas stream. Filterable PM_{2.5} consists of particulate matter less than 2.5 μm in size that is collected on an appropriate filter in a stack sampling train. Condensable PM_{2.5} is defined by EPA as “material that is vapor phase at stack conditions, but which condenses and/or reacts upon cooling or dilution in the ambient air to form solid or liquid particulate matter immediately after discharge from the stack. Note that all condensable particulate matter is assumed to be in the PM_{2.5} size fraction.”

Secondary PM_{2.5} Formation and PM_{2.5} Precursor Emissions

EPA has identified several gases as potential precursors of PM_{2.5} and requires consideration of each in NSR permitting as follows:

- Sulfur dioxide (SO₂) – treated as a precursor in all areas;
- Nitrogen oxides (NO_x) – presumed to be a precursor in all areas unless state or EPA rebuts presumption;
- Volatile Organic Compounds (VOC) – not regulated as a precursor unless the state or EPA provides a demonstration that VOCs are a significant contributor to ambient PM_{2.5} concentrations; and
- Ammonia (NH₃) – not regulated as a precursor, but can be regulated case-by-case in non-attainment areas.

In the *Federal Register*, EPA acknowledges that three of the four listed potential precursor pollutants are criteria pollutants that are already regulated and typically subject to limits in an NSR permitting review. Therefore, regulation of these pollutants as precursors for PM_{2.5} “is not expected to add a major burden to regulated sources.” The proposed SCR Project will not result in any emissions increases for these regulated precursors from CGS Unit 1. The area in which CGS is located is designated attainment, and therefore ammonia is not regulated as a precursor here. Therefore, secondary PM_{2.5} emissions are not considered.

a. STEP 1. Identify All Potential Control Technologies

Primary filterable PM controls include ESPs and FFs. Acid gas controls include wet and dry FGD. Condensed acid gas controls include reagent injection (HLI and SDA) and WESP technologies.

A single piece of emissions control equipment often controls multiple pollutants, and multiple pieces of pollution control equipment work together to control emissions of various pollutants to certain levels. For these reasons, it is necessary to evaluate the control equipment system as



a whole. The following discussion of potential PM_{2.5} control options will focus on control options that can enhance the removal of PM_{2.5} beyond the proposed BACT for H₂SO₄: hot-side ESP and WFGD.

Hot-side ESPs have excellent filterable PM removal capabilities and poor vapor-phase acid gas removal capabilities. WFGD systems have excellent vapor-phase acid gas removal capabilities, and poor filterable PM control capabilities. Table 5 below presents a description of PM BACT control technologies which are potentially transferable to CGS Unit 1 for improving the control of PM_{2.5}.

Table 5: Typical Control Technologies for Total PM

Control Technology	Primary PM _{2.5} Component Controlled
Project Controls also BACT for H ₂ SO ₄	
Hot-side ESP	Filterable particulate
WFGD	Vapor phase acid gases and some filterable and condensed particulate
Additional Compatible Controls	
FF	Filterable and condensed particulate and vapor phase acid gases if capturing alkaline ash or if alkaline sorbent is injected
WESP	Filterable and condensed particulate
Reagent Injection	Vapor phase acid gases
– Solid type	
– Liquid type	
– Gaseous Type	

The addition of a FF downstream of the air heater would reduce filterable and condensed PM_{2.5}. The FF would also reduce vapor-phase acid gas, such as H₂SO₄, hydrogen chloride, and hydrogen fluoride, if the coal fly ash is alkaline, which it is for CGS Unit 1 because of the high percentage of PRB coal fired. Also, the injection of alkaline solids (e.g., lime) before the FF would enhance the removal of vapor-phase acid gas. Other additional control options effective at removing filterable and condensable PM_{2.5} include the use of a WESP and the use of reagent injection.

b. STEP 2. Identify Technically Feasible Control Technologies

As noted above, filterable and condensable PM_{2.5} and vapor-phase condensable gases are controlled to varying degrees using particulate matter and acid gas control systems. As identified in Step 1, filterable (solid and liquid) and condensable (acid gases) controls are considered to address PM_{2.5} emissions. CGS Unit 1 PM_{2.5} emissions may be further reduced through the application of FF, WESP, or reagent injection technologies. The use of these controls for PM_{2.5} specifically at CGS Unit 1 is discussed below.

(1) Fabric Filter

Fabric filters separate dry particles from the boiler flue gas by



filtering the flue gas through fabric filters or “bags.” The components of a FF include the fabric bags, a tube sheet to support the bags, a gas-tight enclosure, a mechanism to clean accumulated PM from the bags, and a hopper to collect accumulated particulate. Typical FF configurations at coal-fired power plants include downstream of the units air heaters or downstream of a spray dryer vessel if the FF is also being used as a component of a dry FGD system.

Fabric filters have several advantages when used for PM control from coal-fired boilers, including:

- High particulate matter control efficiencies;
- Relatively constant outlet grain loading over the entire boiler load range; and
- Simple operation and maintenance.

For CGS Unit 1, the primary PM control device is the hot-side ESP. Installing a FF is a major retrofit applications having capital and operating costs much greater than the installation of a WESP. Also installing a FF is a major retrofit application having capital and operating costs much higher than the installation of a WESP.

(2) Wet Electrostatic Precipitator

As discussed previously, WESPs are not used as the primary particulate control device for coal-fired PC boilers, but are used as a tertiary particulate control device downstream of a wet FGD system. WESPs require that the flue gas be at or near moisture saturation to prevent evaporation of moisture from the wet collection surfaces. For large flue gas flow applications, plate type WESPs are most commonly used. Membrane WESPs have been commercially demonstrated at industrial scale and have been pilot tested on coal-fired PC boiler flue gas. Table 6 summarizes the study results of a membrane WESP as compared to a metal plate WESP.

Table 6: PM_{2.5} Emissions Evaluation for Metal-Plate and Membrane WESP

Parameter	Metal Plate WESP		Membrane WESP	
	Low Velocity	Moderate Velocity	Low Velocity	Moderate Velocity
Comparative ESP Gas Velocities				
PM Reduction %	93	70	96	80

Based on the above data, it can be concluded that a WESP can remove approximately 70% to 90% of the H₂SO₄ and fine PM (filterable and condensable).

(3) Reagent Injection

Reagent injection systems are described previously under the H₂SO₄ BACT (refer to Section B.1.4.1). In addition to removing



H₂SO₄, reagent injection systems using alkaline reagents also remove hydrogen fluoride (HF) and hydrogen chloride (HCl), both of which contribute to PM_{2.5} emissions. However, reagent injection systems do not reduce filterable PM_{2.5}, as do FFs, dry ESPs, FGDs and WESPs. Additionally, as previously discussed, all of the reagent injection technologies would increase the amount of filterable PM in the CGS Unit 1 flue gas. From a PM_{2.5} emission control basis on CGS Unit 1, this increase cannot be completely controlled by the WFGD system, and as a result, reagent injection without the use of a FF before the CGS Unit 1 WFGD is rejected as being technically infeasible for the control of PM_{2.5}.

c. STEP 3. Rank the Technically Feasible Control Technologies

WESP technology and FF technology, with or without reagent injection, are considered technically feasible for application on CGS Unit 1 for the reduction of PM_{2.5}. The WESP technology would be installed after the existing WFGD system and before the wet stack. The FF technology would be installed before the existing WFGD. The retrofit difficulty and costs for the FF technology would be significantly greater than for the WESP technology. The expected achievable emission rates for both the WESP technology and FF technology would be 0.0066 lb/MMBtu for condensable and filterable PM_{2.5}. Note the estimated controlled emission rate of 0.0066 lb/MMBtu is much lower than permitted emission limits, but is consistent with the WESP test data presented in Step 2, Table 6, for the low velocity tests.

d. STEP 4. Evaluate the Most Effective Controls

Because the cost of the FF technology would be much greater than the WESP technology with the same achievable emission rate, only the WESP technology will be addressed in Step 4. Based on the Step 3 discussion, the highest level of total PM_{2.5} control for CGS Unit 1 is the use of a WESP (assuming on average 80% control efficiency). Table 7 presents the economic impacts for reducing PM_{2.5} emissions. The results, along with the environmental and energy impacts are discussed in the following subsections.

Table 7: Summary of PM_{2.5} BACT Impacts for a WESP

Parameter	Baseline	WESP
Boiler Heat Input, MMBtu/hour (HHV)	4,719	
Unit Gross Generation, kW	410,000	
Controlled Emission Rate, lb/MMBtu	0.033	0.0066
Potential PM Emissions, tons per year	682	136
WESP Total Capital Requirement, \$	n/a	\$29,112,000
Capital Recovery Factor (CRF)	n/a	0.0944
Annual Capital Cost, \$/yr	n/a	\$2,748,000
Annual O&M Cost, \$/yr	n/a	\$5,487,000
Total Annual Cost, \$/yr	n/a	\$8,235,000



Parameter	Baseline	WESP
Ton Reduced, tons/ year	0	546
Average Cost, Effectiveness, \$/ ton	n/a	\$15,092

(1) Environmental Impacts

The primary environmental impact of adding the WESP after the WFGD is the reduction in total PM_{2.5} emissions from 0.033 to 0.0066 lb/MMBtu. The addition of a WESP would reduce potential PM_{2.5} emissions from 682 tons per year at 0.033 lb/MMBtu to 136 tons per year at 0.0066 lb/MMBtu, resulting in an incremental reduction in total PM_{2.5} emissions of 546 tons per year. On the negative side, an acid waste water stream is generated which will require additional processing before disposal of the wet solids and the waste water stream.

(2) Economic Impacts

The addition of a WESP after the WFGD system would have a significant economic impact. The capital cost of retrofitting a WESP on top of the current WFGD system is estimated at \$29.1 million based on a cost of \$26.5 dollars per wet standard cubic feet of flue gas. This equates to \$64 per kilowatt which is consistent with the costs reported by others for retrofit installations. The total annual cost of \$8.2 million per year is based on:

- A capital recovery factor of 0.0944 (20-year life and 7% societal cost of money per U.S. EPA guidance); and
- Annual operating and maintenance cost of \$5 per standard cubic feet a minute (scfm).

From Table 7, it can be seen that the incremental cost effectiveness of adding a WESP to the existing WFGD outlet duct work is greater than \$15,000 per ton of PM_{2.5} reduced. This is a very high cost of control demonstrating that the addition of a WESP is not cost effective as BACT.

(3) Energy Impacts

The primary energy impacts of the WESP technology would be increased electrical demand for operation of the WESP and additional ID fan power requirements for the increase in pressure drop.

e. STEP 5. Proposed PM₁₀ and PM_{2.5} BACT Determination

Based on the Step 4 analysis, the application of WESP technology is not BACT. This control option would have significant, adverse economic impacts and would provide negligible, beneficial environmental impacts, as reflected in the calculated cost effectiveness value of more than \$15,000 per ton of PM₁₀/ PM_{2.5} removed.



Therefore, ADEQ has determined an emission limit of 0.033 pounds per MMBtu heat input, expressed as total filterable and condensable particulate matter, represents BACT for both PM₁₀ and PM_{2.5} emissions from CGS Unit 1. Compliance with this limit will be determined using EPA Reference Methods 5 and 202, based on the average of three test runs of at least two hours each. This limit reflects the use of low-sulfur western coals and ultra-low activity SCR catalyst, and continuous performance of the existing boiler, HESP, and WFGD system in accordance with good air pollution control practice. An emission limit expressed as total filterable and condensable particulate matter is an appropriate surrogate for PM₁₀ and PM_{2.5} emissions because, as discussed above, the reference method for filterable particulate matter in particle size ranges less than 10 µm or less than 2.5 µm is not feasible for use at Unit 1.

IV. Monitoring Requirements

- A.** At all times, the Permittee will calibrate, maintain, and operate CEMS, in full compliance with the requirements found at 40 CFR Part 75, to accurately measure SO₂, NO_x, diluent, and stack gas volumetric flow rate from each unit.
- B.** At all times, the Permittee will calibrate, maintain, and operate CEMS, in full compliance with the requirements found at 40 CFR Part 75, to accurately measure SO₂ emissions and diluent at the inlet of the sulfur dioxide control device.
- C.** All valid CEMS hourly data will be used to determine compliance with the emission limitations for NO_x and SO₂.

V. Recordkeeping Requirements

The Permittee will maintain the following records for 5 years:

- A.** All CEMS data, including the date, place, and time of sampling or measurement; parameters sampled or measured; and results;
- B.** Daily 30-boiler-operating-day rolling emission rates for NO_x and SO₂, when applicable, for each unit;
- C.** Records of quality assurance and quality control activities for emissions measuring systems, including, but not limited to, any records required by 40 CFR Part 75;
- D.** Records of the relative accuracy test for hourly NO_x and SO₂ lb/hr measurement and hourly heat input measurement;
- E.** Records of all major maintenance activities conducted on emission units, air pollution control equipment, and CEMS; and
- F.** Any other records required by 40 CFR Part 75.

VI. Testing

- A.** Within 180 days of installation and commencing operation of the SCR system on Unit 1, the Permittee will demonstrate compliance with the PM₁₀ emission limitation by conducting a stack test to measure PM₁₀ using EPA Method 5, in 40 CFR part 60, Appendix



A and Method 202 in 40 CFR Part 51, Appendix M. Subsequent testing shall be conducted annually.

- B. Within 180 days of commencement of operation of the SCR system on Unit 1, the Permittee will demonstrate compliance with the H₂SO₄ emission limitation using EPA Conditional Test Method 13 (CTM-13) or an alternate test method approved by ADEQ. Subsequent testing shall be conducted annually.

VII. Air Dispersion Modeling Analysis

This section presents a summary of the PSD ambient air dispersion modeling analysis conducted in support of this permit revision. The full modeling report, including detailed information regarding model selection, receptor location, and modeling procedures, are included in Appendix G of the application submitted by SRP in January 2016. As described in Section III.A.3.a, the proposed SCR Project will result in PSD significant emission increases of PM₁₀, PM_{2.5}, and H₂SO₄ and therefore an air dispersion modeling analysis was required. Because there were no emission increases of PM_{2.5} precursors, the PM_{2.5} air quality analysis addressed direct PM_{2.5} air quality impacts.

A. Significant Impact Level Results

The PM₁₀ and PM_{2.5} emission increases resulting from the Project were modeled in accordance with ADEQ’s “Air Dispersion Modeling Guidelines for Arizona Air Quality Permits”. The resulting ambient impacts were compared with the Class II Significance Impact Levels (SILs). In accordance with ADEQ guidance, if the maximum ambient impacts resulting from the proposed emission increase are below their respective SILs, a full impact analysis (NAAQS and PSD Increment) for that pollutant is generally not required.

Table 8: Summary of Maximum Impacts Compared to PSD Modeling Class II Significant Impact Levels

Pollutant	Averaging Period	Maximum Concentration (µg/m ³)	Class II Significant Impact Level (SIL) (µg/m ³)	Additional Modeling Required?
PM ₁₀	24-hour	1.61	5	No
	Annual	0.35	1	
PM _{2.5}	24-hour	1.42	1.2	Yes
	Annual	0.32	0.3	

Table 9: Summary of Maximum Impacts Compared to PSD Modeling Class I Significant Impact Levels

Pollutant	Averaging Period	Maximum Concentration (µg/m ³)	Class I Significant Impact Level (SIL) (µg/m ³)	Additional Modeling Required?
PM ₁₀	24-hour	0.14	0.30	No
	Annual	0.01	0.20	
PM _{2.5}	24-hour	0.08	0.07	Yes



	Annual	0.01	0.06	
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Results presented in Tables 8 and 9 above indicate that the maximum ambient impacts for PM₁₀ are below the Class I and Class II SILs. As a result, full NAAQS and PSD increment analyses are not required for PM₁₀. For PM_{2.5}, the maximum ambient impacts are above the Class II and Class I SILs and therefore additional modeling is required for PM_{2.5}. For the Class I analysis, the Permittee used the CALPUFF model to evaluate impacts on the two Class I areas located towards the direction from CGS to the receptors where AERMOD show impacts that exceeded the Class I SIL. Results of this modeling are included in the Appendix G of the PSD application that show impacts below the Class I SIL and therefore will not threaten the Class I increment.

B. NAAQS and PSD Increment Modeling Results

The PM_{2.5} emission increases resulting from the SCR Project were modeled to demonstrate compliance with the PM_{2.5} NAAQS and PSD increments. For the NAAQS analysis, the other PM_{2.5} emissions points at CGS, along with nearby sources, were included in the modeling. This Project established the PM_{2.5} minor source baseline date for this area, and therefore was the only source included in the increment analysis. Tables 10 and 11 below show that the maximum ambient impacts for PM_{2.5} are below the applicable NAAQS and PSD increment.

Table 10: Summary of PM_{2.5} Modeled NAAQS Impacts

Pollutant	Averaging Period	Maximum Concentration (µg/m ³)	Background Concentration (µg/m ³)	Total Concentration (µg/m ³)	NAAQS (µg/m ³)
PM _{2.5}	24-hour	10.49	12.0	22.96	35
	Annual	4.04	5.3	9.34	12

Table 11: Summary of PM_{2.5} Modeled Increment Assessment

Pollutant	Averaging Period	Maximum Concentration for Increment (µg/m ³)	Increment Concentration (µg/m ³)
PM _{2.5}	24-hour	1.42	9
	Annual	0.32	4

Therefore, the proposed SCR Project will not cause or contribute to a violation of the NAAQS or PSD increment.

C. Additional Impacts Analysis

1. Growth Impact Analysis

Pursuant to A.A.C. R18-2-407(I), the general commercial, residential, industrial, and other growth associated with a major modification must be characterized in order to allow for analyses of air quality impacts and impairment to visibility, soils,



and vegetation that would occur as a result of this growth.

The proposed SCR Project is not expected to affect commercial, residential, industrial, or other growth in the area. No new jobs are anticipated to result from the SCR Project. Any additional labor needed during the construction phase of the Project is expected to be drawn from the existing labor force. Therefore, no effects on air quality or on impairment to visibility, soils, and vegetation as a result of growth have been identified.

2. Analysis of Impairment to Soils and Vegetation

Emissions from the proposed SCR Project are not expected to result in significant impairment to soils, crops, or plant species of concern, within the vicinity of the Project site. For each pollutant of concern, the predicted ambient concentration or the predicted deposition rate is well below the secondary NAAQS and the minimum screening values established by EPA. Nothing in the scientific literature identified during this review indicates that the secondary NAAQS and minimum EPA screening values are not protective of any identified crops, and the predicted ambient concentration and deposition rate are less than the screening values established by other governmental authorities.

VIII. LIST OF ABBREVIATIONS

A.A.C	Arizona Administrative Code
ADEQ	Arizona Department of Environmental Quality
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BTB	Better than BART
CD	Consent Decree
CFR	Code of Federal Regulations
CGS	Coronado Generating Station
CPP	Clean Power Plan
CRF	Capital Recovery Factor
DFGD	Dry Flue Gas Desulfurization
EPA	United States Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
FF	Fabric Filter
FGD	Flue Gas Desulfurization
FIP	Federal Implementation Plan
FR	Federal Register
HHV	High Heat Value
HLI	Hydrated Lime Injection
ID	Induced Draft
H ₂ SO ₄	Sulfuric Acid
Lb	Pound
Lb/MMBtu	Pound per Million Btu
MMBtu	Million British thermal unit
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO _x	Nitrogen Oxides
NSPS	New Source Performance Standards
O&M	Operation and Maintenance



PC	Pulverized Coal
PM	Particulate Matter
PM _{2.5}	Particulate Matter less than 2.5 microns
PM ₁₀	Particulate Matter less than 10 microns
PRB	Powder River Basin
PSD	Prevention of Significant Deterioration
RBLC	RACT/BACT/LAER Clearinghouse
RHR	Regional Haze Rule
RUL	Remaining Useful Life
SCR	Selective Catalytic Reduction
SDA	Spray Dryer Absorber
SI	Sorbent Injection
SIP	State Implementation Plan
SO ₂	Sulfur Dioxide
SO ₃	Sulfur Trioxide
SPR	Significant Permit Revision
SRP	Salt River Project
ULA	Ultra Low Activity
WESP	Wet Electrostatic Precipitator
WFGD	Wet Flue Gas Desulfurization