Enchant / Farmington
San Juan Generating Station Units 1 & 4

NEW MEXICO REGIONAL HAZE RULE
SECOND IMPLEMENTATION PERIOD FOUR-FACTOR ANALYSIS

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EXECUTIVE SUMMARY

The Federal Regional Haze Rule, 40 C.F.R. §§51.308 – 51.309, requires each State to submit a State Implementation Plan (SIP) addressing visibility impairment caused by regional haze in 156 federally-protected parks and wilderness areas (Class I areas), including nine such areas in New Mexico and Class I areas in surrounding states. On October 9, 2014, the U.S. Environmental Protection Agency (U.S.EPA) approved revisions to the New Mexico Regional Haze SIP for the initial regional haze planning period, including provisions in the SIP addressing the Best Available Retrofit Technology (BART) requirement for nitrogen oxide (NOx) emission for the San Juan Generating Station (SJGS) in San Juan County, New Mexico (79 Fed. Reg. 60985).

SJGS is a coal-fired, steam electric generating facility located in northwest New Mexico, approximately 15 miles northwest of the City of Farmington. SJGS currently has two operating coal-fired steam electric generating units, Units 1 & 4, and two recently retired units, Units 2 & 3.[1] Revisions to the New Mexico SIP, and approved by U.S.EPA, incorporated into the State's SIP provisions of a Term Sheet Agreement dated February 15, 2013 between New Mexico, U.S.EPA, and Public Service Company of New Mexico (PNM), the majority owner and operator of SJGS. The core agreement, as provided in the Term Sheet, was that PNM would retire SJGS Units 2 & 3 by December 31, 2017, and install selective non-catalytic reduction (SNCR) NOx control systems on SJGS Units 1 & 4.

The Regional Haze Rule requires States to update their Regional Haze SIPs every 10-years to ensure reasonable progress towards meeting the goal of achieving natural visibility conditions at Class I areas by 2064. SIPs for the second planning period, which ends in 2028, must be submitted to U.S.EPA for review and approval by July 31, 2021. Among other things, second planning period SIPs must include an evaluation of emission reductions from existing sources that may impact visibility in one or more Class I area. Emission reductions from existing sources are to be determined based on a reasonable progress "four-factor analysis" of available emission control technologies.

[1] On March 16, 2020, PNM applied to NMED for a permit to construct the Pinon Energy Center (PEC), a new seven unit natural gas-fired simple-cycle combustion turbine generating facility, to be located southwest of SJGS. PNM proposed PEC as a modification of SJGS. However, PEC will be operated as a separate facility from SJGS and will operate after PNM abandons its interest in SJGS. As a result, the SJGS Four-Factor Analysis does not include an evaluation of emission controls for the proposed PEC.

The New Mexico Environment Department (NMED) requested a four-factor analysis for SJGS from PNM. However, it is our understanding that PNM has not submitted a four-factor analysis for SJGS based on its announced intent to abandon its interest in the plant by June 30, 2022.[2] The City of Farmington (Farmington) has the right under a participation agreement between current facility owners to acquire interests held by all other owners effective June 30, 2022. Enchant Energy LLC (Enchant) has entered into an agreement with Farmington to develop and manage a carbon capture utilization and storage (CCUS) control system to remove carbon dioxide (CO_2) from SJGS Unit 1 & 4 flue gas. Enchant intends to acquire ownership of SJGS, with the exception of Farmington's current plant ownership interest, by June 30, 2022. Thus, even though PNM currently remains the majority owner and operator of SJGS, NMED requested the reasonable progress four-factor analysis from Enchant and Farmington (collectively Enchant/Farmington).

Sargent & Lundy, LLC (Sargent & Lundy) was retained by Enchant/Farmington to prepare a reasonable progress four-factor analysis (the Four-Factor Analysis) for the control of sulfur dioxide (SO_2) and nitrogen oxide (NO_X) emissions from SJGS. The SJGS Four-Factor Analysis includes an assessment of potentially available emission reduction measures taking into consideration the four statutory factors listed in 40 CFR 51.308(f)(2). Technically feasible SO_2 and NO_X emission reduction measures are evaluated for the following four statutory factors:

- Factor 1: The cost of compliance
- Factor 2: The time necessary to achieve compliances
- Factor 3: The energy and non-air quality environmental impact of compliance
- Factor 4: The remaining useful life of any existing source subject to such requirements

Summary of the SJGS Units 1 & 4 NOx Four-Factor Analysis

Based on a review of physical, chemical, and engineering principles, and an assessment of NOx control technologies installed on existing coal-fired boilers, as well as operational practices and equipment upgrades already implemented on SJGS Units 1 & 4, the only potentially available option to further NOx control on SJGS Units 1 & 4 is replacing the existing SNCR control systems with selective catalytic reduction (SCR). Other potentially available NOx control technologies would not achieve additional NOx reduction beyond that achieved with the exiting SNCR systems. Innovative NOx control technologies, and multi-pollutant control technologies, have not developed beyond the

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[2] The San Juan Generating Station is currently owned by a group of public utilities, investor owned utilities, and municipal power entities pursuant to an Amended San Juan Participation Agreement (ASJPA). Current plant ownership includes PNM, Tucson Electric Power, the City of Farmington, Los Alamos County, NM and Utah Associated Municipal Power Systems. Its majority owner and facility operator, PNM, has announced its intent to abandon its interest in the plant by June 30, 2022.

demonstration stage, have not been demonstrated on large coal-fired boilers, or are not commercially available. Similarly, the hybrid SNCR/in-duct SCR control system would pose significant engineering and design challenges to determine technical feasibility and effectiveness on SJGS Units 1 & 4 and is therefore not an available NOx control technology.

Table E-1 provides a comparison of emission rates achieved with SNCR and emission rates achievable with retrofit SCR, the only technically feasible and commercially available NOx control technology at SJGS. Emission rates shown in Table E-1 represent annual average emission rates that the control options would be expected to achieve during normal operations.

Table E-1. Technically Feasible NOx Control Options for SJGS Units 1 & 4

Control Technology	Unit 1	Unit 4
Baseline (existing LNB, OFA, SNCR)	0.223	0.226
SCR	0.05	0.05

Note 1. Emission rates shown above represent average emissions that each control option would be expected to achieve on an ongoing long-term basis under normal operating conditions. Emission rates are provided for comparative purposes only and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control-system-specific basis, and additional compliance margin would likely be needed to account for all operating conditions.

Table E-2 and Table E-3 present the total capital investment, annualized capital cost, annual operating and maintenance (O&M) costs, and total annual costs associated with installing and operating SCR on SJGS Units 1 & 4. As discussed in Section 5.2.4 of this evaluation, capital costs were annualized using two different equipment lives: (1) an equipment life of 7-years based on the assumption that facility operations cease in 2035; and (2) and equipment life of 20-years based on the assumption that operations extend beyond 2048. Table E-4 show the average annual cost effectiveness for the control system for both scenarios. Additional cost details are provided in Appendix B.

Table E-2. NOx Control Cost Summary ($2020)
SJGS Units 1 & 4 – Assuming Equipment Life of 20-Years

Unit	NOx Control Option	Total Capital Investment $	Annual Capital Cost $/yr.	Annual Operating Cost $/yr.	Total Annual Cost $/yr.
Unit 1	SCR	$193,045,300	$18,222,000	$11,330,000	$29,552,000
Unit 4	SCR	$259,358,600	$24,482,000	$15,491,000	$39,973,000

Table E-3. NOx Control Cost Summary ($2020)
SJGS Units 1 & 4 – Assuming Equipment Life of 7-Years

Unit	NO_X Control Option	Total Capital Investment $	Annual Capital Cost $/yr.	Annual Operating Cost $/yr.	Total Annual Cost $/yr.
Unit 1	SCR	$193,045,300	$35,820,000	$11,330,000	$47,150,000
Unit 4	SCR	$259,358,600	$48,125,000	$15,491,000	$63,616,000

Table E-4. NOx Control Cost Effectiveness ($2020)
SJGS Units 1 & 4

Unit	NO_X Control Option	Total Annual Cost ($/yr.)		Expected Emission Reduction	Average Annual Cost Effectiveness ($/ton)	
		20- Year Equipment Life	7-Year Equipment Life	NOx tpy	20-Year Equipment Life	7-Year Equipment Life
Unit 1	SCR	$29,552,000	$47,150,000	2,417	$12,227	$19,508
Unit 4	SCR	$39,973,000	$63,616,000	3,627	$11,021	$17,540

Based on costs and emission reductions summarized in Tables E-2 through E-4 the average cost effectiveness of retrofit SCR on SJGS Units 1 & 4 is $12,227/ton and 11,021/ton, respectively assuming facility operations extend beyond 2048. Average cost-effectiveness is calculated based on baseline 2028 NOx emission rates of 0.223 and 0.226 lb./MMBtu for Units 1 & 4, respectively, a controlled NOx emission rate of 0.05 lb./MMBtu with SCR, and assuming a 2028 annual capacity factor of approximately 87% for each unit. In the event facility operations cease prior to 2048, annualized capital costs increase, and the control systems become less cost-effective. Assuming an equipment life of 7-years, the average cost effectiveness of retrofit SCR on SJGS Units 1 & 4 increases to $19,508/ton and $17,540/ton, respectively.

Summary of the SJGS Units 1 & 4 SO_2 Four-Factor Analysis

SJGS Units 1 & 4 are currently equipped with wet flue gas desulfurization (WFGD) SO_2 control systems. The SJGS WFGD control systems currently achieve very effective SO_2 control. Operational changes and equipment upgrades have been integrated into the WFGD control systems at SJGS to achieve adequate slurry injection rates, calcium-to-sulfur (Ca:S) stoichiometric ratios, liquid-to gas ratios (L/G), and slurry/flue gas distribution and mixing. In addition, a dibasic acid (DBA) additive system is available to control absorber vessel pH and reaction chemistry. The control systems currently achieve SO_2 removal efficiencies of 95% or greater, and consistently achieve controlled SO_2 emission rates of 0.06 lb./MMBtu or less. Based on a review of potentially available control options, it is unlikely that operational changes and equipment upgrades would provide additional SO_2 removal beyond that currently achieved at SJGS.

As noted in Section II.B.3.f of U.S.EPA's 2019 Second Planning Period Guidance Document (*Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*), "[i]f a source owner has recently made a significant expenditure that has resulted in significant reductions of visibility impairing pollutants at an emissions unit, it may be reasonable for the state to assume that additional controls for that unit are unlikely to be reasonable for the upcoming implementation period." Examples provided in the EPA Guidance Document include FGD control systems that meet the applicable Mercury and Air Toxic Standard (MATS) SO_2 emission limit of 0.2 lb./MMBtu for coal-fired EGUs, and FGD systems that operate year-round with an effectiveness of at least 90%. The WFGD control systems at SJGS currently achieve SO_2 removal efficiencies of 95% or more and SO_2 emission rates well below the applicable MATS limit. Thus, no additional upgrades or modifications to the existing WFGD control systems are warranted for the second planning period.

Projected 2028 SJGS Emissions

Based on the review of potentially available NOx and SO_2 control technologies, including technical feasibility, effectiveness, costs, cost-effectiveness, and the remaining statutory factors, projected emissions from SJGS Units 1 & 4 in 2028 are summarized in Table E-5

Table E-5. Projected 2028 Baseline SO_2 / NOx Emissions for SJGS Units 1 & 4

Pollutant	Representative Baseline Periods	
	Unit 1 Note 1	Unit 4
Full Load Heat Input	3,667 MMBtu	5,409 MMBtu
Projected Annual Heat Input	27,946,940 MMBtu	41,223,071 MMBtu
Projected Annual Capacity Factor	87%	87%
SO_2 Controls	WFGD	WFGD
Projected 2028 SO_2 Emissions	0.037 lb./MMBtu (hourly) 0.019 lb./MMBtu (annual)	0.056 lb./MMBtu (hourly) 0.028 lb./MMBtu (annual)
	136 lb./hr.	303 lb./hr.
	265 tpy	557 tpy

Pollutant	Representative Baseline Periods	
	Unit 1 Note 1	Unit 4
NOx Controls	LNB/OFA/NN + SNCR	LNB/OFA/NN + SNCR
Projected 2028 NOx Emissions	0.223 lb./MMBtu	0.226 lb./MMBtu
	818 lb./hr.	1,222 lb./hr.
	3,116 tpy	4,658 tpy

Projected 2028 emission calculations are based on the following assumptions:

- The projected NOx emission rates (lb./MMBtu) were set equal to the 2017-2019 baseline rates based on the assumption that SJGS Units 1 & 4 will continue to control NOx emissions using a combination of combustion controls and SNCR. No credit was taken for potential NOx emission reductions associate with the carbon capture facility.
- The projected short-term SO_2 emission rates (lb./MMBtu) were set equal to the 2017-2019 baseline rates based on the assumption that SJGS Unit 1 & 4 will continue to operate the existing WFGD control systems with no credit taken for SO_2 emission reductions associated with the carbon capture facility. Annual average SO_2 emissions were calculated assuming an additional 50% SO_2 reduction through the carbon capture system.
- Annual emissions were calculated assuming an annual capacity factor of approximately 87% to account for increased boiler utilization in 2028.

1. INTRODUCTION

Sargent & Lundy, LLC (Sargent & Lundy) was retained by the City of Farmington and Enchant Energy (collectively Enchant/Farmington) to prepare a Reasonable Progress Four-Factor Analysis (Four-Factor Analysis) for the control of sulfur dioxide (SO_2) and nitrogen oxide (NO_X) emissions from the San Juan Generating Station (SJGS).

The SJGS Four-Factor Analysis was prepared in response to a request from the New Mexico Environment Department (NMED) and includes an assessment of potentially available emission reduction measures taking into consideration the four statutory factors listed in 40 CFR 51.308(f)(2). The analysis was prepared in accordance with guidance provided by the U.S. Environmental Protection Agency (EPA) in its publication *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period* (the "EPA Guidance Document").[3] Technically feasible SO_2 and NO_X emission reduction measures are evaluated for the following four statutory factors:

- Factor 1: The cost of compliance
- Factor 2: The time necessary to achieve compliances
- Factor 3: The energy and non-air quality environmental impact of compliance
- Factor 4: The remaining useful life of any existing source subject to such requirements

The four statutory factor are specifically listed in Section 169A(g)(1) of the Federal Clean Air Act, 42 U.S.C. §7491(g)(1). In addition, §51.308(f)(2)(i) of the Regional Haze Rule requires States to "evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment."

[3] EPA published guidance on August 20, 2019 to fulfill the Agency's September 11, 2018 commitment in the "*Regional Haze Reform Roadmap*" to release a series of implementation tools and guidance documents that will help focus states' efforts and reduce and streamline the time and resources needed to meet the statutory and regulatory requirements for reducing regional haze in National Parks, wildlife refuges, and wilderness areas."

2. REGULATORY BACKGROUND

The Federal Regional Haze Rule, 40 C.F.R. §§51.308 – 51.309, requires each State to submit a State Implementation Plan (SIP) addressing visibility impairment caused by regional haze in 156 federally-protected parks and wilderness areas (Class I areas), including nine such areas in New Mexico and Class I areas in surrounding states. The nearest Class I area to SJGS is the Mesa Verde National Park located approximately 50 km north of SJGS in southwest Colorado. The rule provides for two alternative approaches, described in 40 C.F.R. §51 Section 308 and Section 309. Section 309 is an alternative available only to certain western states and tribes, and contains provisions to implement the recommendations of the Grand Canyon Visibility Transport Commission (GCVTC). Section 308 describes the approach for states that are not eligible for, or chose not to opt into, the Section 309 approach. On December 31, 2003, the New Mexico Environmental Improvement Board (Board) approved a Section 309 SIP that addressed sulfur dioxide (SO_2) emissions from New Mexico sources by creating SO_2 emission milestones and an emissions trading program, but deferred the Section 308 Best Available Retrofit Technology (BART) requirements with respect to NOx and particulate matter (PM).

In 2006, in response to numerous judicial challenges, EPA issued a revised Regional Haze Rule that allowed States to submit revised Section 309 SIPs and established a submittal deadline of December 17, 2007.[4] New Mexico missed the 2007 deadline; however, on June 3, 2011, the Board approved a revised Section 309 SIP. The 2011 SIP included BART determinations for NOx and PM for SJGS. SJGS was identified in the SIP as the only facility in New Mexico subject to the BART requirements. Specifically, the 2011 SIP identified selective non-catalytic reduction (SNCR) with an emission limit of 0.23 lb./MMBtu as BART for NOx control on SJGS Units 1 thru 4. On August 22, 2011, EPA disapproved "the New Mexico Interstate Transport SIP provisions that address the requirements of [§110(a)(2)(D)(i)(II) of the Federal Clean Air Act]" and promulgated a federal implementation plan (FIP), including a different NOx BART determination for SJGS. The 2011 FIP required selective catalytic reduction (SCR) with an emission limit of 0.05 lb./MMBtu as BART on SJGS Units 1 thru 4.[5]

New Mexico sought judicial review of the EPA's disapproval of the 2011 SIP and approval of the 2011 NOx BART FIP in the U.S. Court of Appeals for the Tenth Circuit. On February 15, 2013, during the pendency of the litigation,

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[4] 71 Fed. Reg. 60612 (Oct. 13, 2006).

[5] 76 Fed. Reg. 52388 (Aug. 22, 2011).

New Mexico, U.S.EPA, and Public Service Company of New Mexico (PNM)[6] signed a tentative settlement agreement that, when fully implemented, would dispose of the case (the Term Sheet). The settlement agreement provided for revisions to New Mexico's SIP with respect to BART for SJGS, and was incorporated into the States' Regional Haze SIP in revisions submitted to EPA on October 7, 2013 and November 5, 2013 (the 2013 RH SIP revision). The core agreement as provided in the Term Sheet was that PNM would retire SJGS Units 2 & 3 by December 31, 2017, and install SNCR on Units 1 & 4 to achieve a controlled NOx emission rate of 0.23 lb./MMBtu within 15 months of EPA's approval of the revised SIP. The 2013 RH SIP revisions were approved by EPA on October 9, 2014 and as a result, EPA rescinded the FIP (79 Fed. Reg. 60985).

[6] At the time of the Term Sheet agreement, PNM was the majority owner and operator of the San Juan Generating Station.

3. FACILITY DESCRIPTION

SJGS is a coal-fired, steam electric generating facility located in northwest New Mexico, approximately 15 miles northwest of the City of Farmington. The generating station currently has two operating coal-fired steam electric generating units, Units 1 & 4, which commenced commercial operation in 1974 and 1982, respectively, and two recently retired units, Units 2 & 3. The retired units have been left in place with some of the auxiliary equipment mothballed.

SJGS is currently owned by a group of public utilities, investor owned utilities, and municipal power entities pursuant to an Amended San Juan Participation Agreement (ASJPA). Current plant ownership includes PNM, Tucson Electric Power, the City of Farmington, Los Alamos County, NM and Utah Associated Municipal Power Systems. Its majority owner and facility operator, PNM, has announced its intent to abandon its interest in the plant by June 30, 2022. Farmington currently holds 5.076% ownership in the facility and has the right under the ASJPA to acquire interests held by all other owners effective at the termination of the existing coal contract with Westmoreland Holdings on June 30, 2022. Enchant has entered into an Agency Agreement with Farmington to develop and manage a carbon capture utilization and storage (CCUS) control system to remove carbon dioxide (CO_2) from SJGS Unit 1 & 4 flue gas. Enchant intends to acquire ownership of SJGS, with the exception of Farmington's current plant ownership interest, by June 30, 2022.[7]

3.1 EXISTING AIR POLLUTION CONTROLS

SJGS Unit 1 is a nominal 370 MW-gross (MWg) Foster Wheeler subcritical wall-fired boiler. SJGS Unit 4 is a nominal 544 MWg B&W subcritical opposed wall-fired boiler. Both units are equipped with state-of-the-art low NOx burners (LNB), with over fired air (OFA) ports, to reduce NO_x emissions. SNCR was installed on SJGS Units 1 & 4 in 2015 to provide additional NOx removal. Full-sized pulse-jet fabric filter (PJFF) baghouses were installed on each unit for PM control, upstream of the existing wet limestone flue gas desulfurization (FGD) systems. The PJFF baghouses are also a component, along with activated carbon injection (ACI), for reducing mercury (Hg) emissions. The existing WFGD control systems were upgraded on both units in the 2007 - 2008 timeframe with the

[7] On March 16, 2020, PNM applied to NMED for a permit to construct the Pinon Energy Center (PEC), a new seven unit natural gas-fired simple-cycle combustion turbine generating facility, to be located southwest of SJGS. PNM proposed PEC as a modification of SJGS. However, PEC will be operated as a separate facility from SJGS and will operate after PNM abandons its interest in SJGS. As a result, the SJGS Four-Factor Analysis does not include an evaluation of emission controls for the proposed PEC.

addition of dibasic acid (DBA) injection. Additional work has also been performed on both units to improve SO_2 removal efficiencies through modification of the spay nozzle sizing and angle and selective blanking of the sieve tray to improve slurry distribution.

3.2 CARBON CAPTURE UTILIZATION AND STORAGE

The New Mexico Energy Transition Act (ETA) requires the Environmental Improvement Board to adopt regulations limiting CO_2 emissions from coal-fired electric generating facilities with an originally installed capacity exceeding 300 MW to no more than 1,100 pounds CO_2 per megawatt-hour (lb./MWh), by January 1, 2023. As of the date of the report, such regulations have not been proposed; however, CCUS technology on affected coal-fired generating facilities will likely be needed in order to achieve the anticipated CO_2 emission reduction requirements.

Enchant/Farmington plan to install CCUS on SJGS Units 1 & 4 to remove CO_2 from the flue gas for carbon sequestration or enhanced oil recovery (EOR). Given the timeframe to achieve emission reductions required by the New Mexico ETA, Enchant/Farmington plan to retrofit SJGS Units 1 & 4 with commercially available technology that has been demonstrated on coal-fired power plants. Based on the current status of CO_2 capture technology, amine-based CO_2 capture is being proposed for SJGS. Amine-based absorption technology has been demonstrated as technically feasible and effective, and has been permanently installed at the Petra Nova coal-fired facility in Texas and the Boundary Dam facility in Canada.

The CCUS carbon capture island at SJGS is proposed to be built directly adjacent to the existing generating units and is intended to treat flue gas produced from the facility. In general, the amine-based CO_2 capture system consists of a flue gas quencher (or pre-scrubber), an absorber where the amine-solvent preferentially absorbs CO_2 from the flue gas, and a stripper where the CO_2 is desorbed from the amine-solvent through the addition of heat. CO_2 from the stripper is then dehydrated and compressed for pipeline transport.

With the possible exception of volatile organic compound (VOC) emissions, installation and operation of the carbon capture system does not result in increased emissions of regulated air pollutants, including SO_2 and NOx. In fact, SO_2 and NOx emissions from the facility will likely decrease as a result of the carbon capture system. For example, amine-based solvents are sensitive to impurities in the flue gas and will react with SO_2 and sulfur trioxide (SO_3) to form non-regenerable heat stable salts, resulting in higher solvent regeneration requirements, additional solvent makeup rates, and increased operational costs. Although SJGS Units 1 & 4 are equipped with recently upgraded WFGD systems for SO_2 control, additional SO_2 and SO_3 removal is required for effective operation of the CO_2 capture system. Additional SO_2 and SO_3 removal will be achieved using a caustic solution to pre-scrub the flue gas upstream of the CO_2 absorber, further reducing SO_2 emissions from the facility.

In addition to SO_2 and SO_3 emission reductions, the CO_2 capture island is expected to result in decreased NOx emissions. NOx emission reductions are expected due to the potential for NOx to form heat stable salts in the CO_2 absorber column. Heat stable salts formed in the absorber column are removed from the system as solid waste, resulting in reduced NOx emissions from the absorber column stacks. Although the carbon capture island is expected to provide an incremental reduction in NOx emissions from the facility, equipment vendors generally do not provide NOx reduction guarantees for amine-based systems. Therefore, for this evaluation, S&L did not account for potential NOx emission reductions that may result from the carbon capture system, and assumed that the carbon capture island would provide no additional NOx control.

Following installation of the carbon capture equipment, Enchant/Farmington will have the ability to operate Units 1 & 4 individually to generate electricity for sale to the grid or send 100% (or any portion thereof) of the flue gas to the carbon capture facility. Thus, emissions may be from the existing stacks, which would not constitute a change in the method of operation of the stationary source, or from the carbon capture absorber stacks, or any combination thereof. Under all operating scenarios emissions from the existing stacks, prior to treatment in the carbon capture system, would result in the highest NOx and SO_2 mass emission rates from the facility and the greatest potential impact to regional haze. Thus, for this evaluation, baseline and projected hourly emissions are calculated assuming SJGS Units 1 & 4 operate at full load to generate electricity, and do not take into consideration potential emission reductions associated with the carbon capture process. Conversely, projected annual emissions (tpy) are calculated assuming 100% of the flue gas from SJGS Units 1 & 4 is treated in the carbon capture process and exhausted through the new carbon absorber column stacks. Thus, annual emissions take into consideration expected SO_2 emission reductions associated with the carbon capture system. Although some NOx reduction is also anticipated with the carbon capture system, this analysis is based on the assumption that the carbon capture system will provide no additional NOx reductions.

3.3 BASELINE OPERATING PARAMETERS

Table 2-1 summarizes the operating parameters used for the SJGS Four-Factor Analysis. Baseline operating parameters were developed from information available for the generating station assuming SJGS Units 1 & 4 are operating at full load to generate electricity without accounting for auxiliary power requirements associated with the carbon capture process. Projected operating parameters were developed based on a preliminary engineering evaluation of the carbon capture system, and account for increased auxiliary power requirements associated with the carbon capture process[8]

Table 3-1. Operating Parameters – SJGS Units 1 & 4

Operating Parameter	Unit 1	Unit 4
Existing Plant Data		
Gross Output (MW_{gross})	370	544
Full Load Heat Input (MMBtu/hr.)	3,667	5,409
Existing Aux Power (MW)	30	37
Existing Net Power (MW_{net})	340	507
Economizer Outlet Temperature (°F)	658	680
Air Preheater Outlet Temperature (°F)	301	240
Stack Gas Temperature (°F)	129	129
Stack Gas Volumetric Flow Rate (acfm)	1,254,165	2,021,601
Stack Gas Mass Flow Rate (lb./hr.)	4,160,664	6,697,983
Plant Data with Carbon Capture		
Gross Output, (MW_{gross})	370	544
Full Load Heat Input, (MMBtu/hr.)	3,667	5,409
Steam to CO_2 System (lb./hr.)	816,000	1,262,000
Plant Derating due to Extraction (MW)	48	74
Total Aux Load for CCS (MW)	49	75
Projected Net Power Output (MW_{net})	243	358
Absorber Column Exhaust Gas Temperature Per Train (°F)	105	
Absorber Column Exhaust Gas Volumetric Flow Rate Per Train (acfm)[1]	635,240	
Absorber Column Exhaust Gas Mass Flow Rate Per Train (lb./hr.)[1]	2,090,290	

Note 1. Absorber column exhaust gas volumetric and mass flow rates are based on a preliminary design of up to four carbon capture island trains designed to treat 100% of the flue gas flow from SJGS Units 1 & 4. Absorber column exhaust conditions provided herein are estimated based on preliminary design and are subject to change based on vendor detailed design.

[8] Operating parameters summarized in Table 3-1 represent typical average conditions and should not be construed as maximum values or unit design values.

4. BASELINE SO_2 AND NO_X EMISSIONS

To establish representative baseline emissions for the Four-Factor Analysis, Sargent & Lundy evaluated SJGS Units 1 & 4 operating data for the three-year period of January 1, 2017 through December 31, 2019, following installation of the SNCR control systems, to identify periods of normal operation (i.e., periods of operation when the boilers were not limited by infrequent or extraordinary operating restrictions). Based on a review of heat input to each boiler, boiler heat rates, and gross power generation, representative operating periods of normal boiler operation were identified for each unit and used to establish baseline annual heat input and emissions (in terms of tons per year (tpy)).

The representative baseline periods and resulting baseline annual emissions for SJGS Units 1 & 4 are summarized in Table 4-1. Baseline annual SO_2 and NO_X emissions were determined based on data obtained from the Unit 1 & Unit 4 continuous emissions monitoring systems (CEMS) and reported to EPA's Clean Air Markets Database. Representative baseline emission factors (in terms of pounds per million British thermal units (lb./MMBtu)) were developed using baseline annual emissions (tpy) and corresponding annual heat inputs (MMBtu).

Table 4-1. Baseline SO_2 / NOx Emissions for SJGS Units 1 & 4

Pollutant	Representative Baseline Periods	
	Unit 1	Unit 2
Baseline Period[1]	1/1/2017 to 12/31/2019	1/1/2017 to 12/31/2019
Baseline Annual Heat Input	23,969,055 MMBtu	39,820,685 MMBtu
Baseline SO_2 Controls	WFGD	WFGD
Baseline NOx Controls	LNB/OFA/NN + SNCR	LNB/OFA/NN + SNCR
Baseline SO_2 Emissions (lb./MMBtu / tpy)	0.037 / 444	0.056 / 1,124
Baseline NOx Emission (lb./MMBtu / tpy)	0.223 / 2,678	0.226 / 4,495

1. Baseline periods exclude those periods of time when the boilers were not operating.

Projected annual emissions from SJGS Units 1 & 4 in 2028 with no new or additional NOx or SO_2 controls are summarized in Table 4-2. Projected 2028 baseline emissions are provided to support New Mexico's regional scale modeling to set Reasonable Progress Goals (RPGs) for the second planning period ending 2028.[9] The EPA Guidance

[9] See, EPA Guidance Document, pg. 1, and pg. 5, Table 1, Step 6.

Document states that estimates of baseline visibility impacts may be represented by either a source's current visibility impacts or impacts it will have in 2028 under existing regulatory requirements.[10] Projected 2028 baseline emissions were calculated based on the following assumptions:

- The projected NOx emission rates (lb./MMBtu) were set equal to the 2017-2019 baseline rates, based on the assumption that SJGS Units 1 & 4 will continue to control NOx emissions with LNB/OFA/NN + SNCR. No credit was taken for potential NOx emission reductions associate with the carbon capture facility.
- The projected SO_2 emission rates (lb./MMBtu) were set equal to 50% of the 2017-2019 baseline rates, based on the assumption that SJGS Unit 1 & 4 will continue to operate the existing WFGD control systems and that the CCUS quencher system will achieve an additional 50% SO_2 emission reductions associated with the carbon capture facility.[11]
- Annual emissions were calculated assuming an annual capacity factor of approximately 87% to account for increased boiler utilization in 2028.

Table 4-2. Projected 2028 Baseline SO_2 / NOx Emissions for SJGS Units 1 & 4

Pollutant	Representative Baseline Periods	
	Unit 1 Note 1	Unit 4
Full Load Heat Input	3,667 MMBtu	5,409 MMBtu
Projected Annual Heat Input	27,946,940 MMBtu	41,223,071 MMBtu
Projected Annual Capacity Factor	87%	87%
SO_2 Controls	WFGD	WFGD
Projected 2028 SO_2 Emissions	0.037 lb./MMBtu (hourly) 0.019 lb./MMBtu (annual average)	0.056 lb./MMBtu (hourly) 0.028 lb./MMBtu (annual average)
	136 lb./hr. (hourly)	303 lb./hr. (hourly)
	265 tpy	577 tpy
NOx Controls	LNB/OFA/NN + SNCR	LNB/OFA/NN + SNCR
Projected 2028 NOx Emissions	0.223 lb./MMBtu	0.226 lb./MMBtu
	818 lb./hr.	1,222 lb./hr.
	3,116 tpy	4,658 tpy

[10] EPA Guidance Document at page 29 states that the projected 2028 (or the current) emissions scenario can be a reasonable choice for use as the baseline control scenario for measuring the incremental effects of potential reasonable progress control measures on emissions, costs, visibility, and other factors. Generally, the estimate of a source's 2028 emissions would be based, at least in part, on information on the source's operation and emissions during a representative historical period.

[11] Pre-scrubbing is expected to reduce emissions down to trace amounts upstream of the CO_2 absorber column, which may require SO_2 removal efficiencies significantly greater than 50% from baseline; however, for this evaluation a 50% removal efficiency is used as a conservative target.

5. NO_X FOUR-FACTOR ANALYSIS

SJGS Units 1 & 4 were retrofit with SNCR NOx control technology in 2015. SNCR was required for NOx control as part of the initial planning period Regional Haze SIP, and the Term Sheet Agreement between PNM, NMED and EPA. Since installing the SNCR control systems, SJGS Units 1 & 4 have achieved average annual NOx emission rates of 0.223 lb./MMBtu and 0.226 lb./MMBtu, respectively.

This section of the SJGS Four-Factor Analysis includes an evaluation of control technologies available to SJGS to achieve further NOx reductions. Sargent & Lundy used a top-down approach to identify all available retrofit emission control technologies, eliminate technically infeasible options or options with no practical applicable to SJGS Units 1 & 4, and rank technically feasible control technologies by effectiveness.[12] Technically feasible NOx control options were evaluated for the four statutory factors listed in 40 CFR 51.308(f)(2).

5.1 NO_X EMISSIONS CONTROLS

5.1.1 Identify Available NO_X Control Options

There are two general approaches to reducing NOx reductions from coal-fired boilers: combustion controls and post-combustion control technologies. Combustion control methods are designed to suppress NOx formation during the combustion process by controlling flame temperature and fuel/oxygen ratio. Combustion control methods include technologies such as low-NOx burners (LNB) and over-fire air (OFA). Neural network (NN) combustion optimization systems may also be installed to work in conjunction with combustion controls to fine-tune burner controls and reduce NOx formation.

Post-combustion NOx controls include SNCR and selective catalytic reduction (SCR) emission control systems. SNCR and SCR are flue gas treatment technologies that reduce NOx emissions following NOx formation in the boiler. The SNCR and SCR NOx control technologies use a reagent (i.e., urea or ammonia) that reacts with NOx, as nitrogen oxide (NO) or nitrogen dioxide (NO_2), to form nitrogen (N_2) and water. Because these reactions proceed slowly at typical boiler exit gas temperatures of a coal-fired steam electric generating unit, the SCR system uses a catalyst designed to increase the reaction rate between NOx and ammonia.

[12] The top-down approach to evaluating potentially feasible control technologies is described in 40 CFR Part 51 Appendix Y, Section IV.D.

In addition to combustion controls, SNCR, and SCR, the SJGS Best Available Retrofit Technology (BART) assessment prepared to inform the initial planning period Regional Haze SIP included an evaluation of alternative NOx control technologies (the 2013 BART Assessment).[13] NOx control technologies that were determined to be technically feasible and applicable at SJGS included combustion controls (i.e., LNB, OFA and NN) and post-combustion SNCR and SCR control systems. Based on the NMED's review of NOx control technologies available to SJGS, including an evaluation of technical feasibility, commercial availability, costs, and cost-effectiveness, NMED concluded that combustion controls and SNCR, combined with the retirement of Units 2 & 3, was BART for NOx control at SJGS.[14] NMED found that the retirement of Units 2 and 3 would reduce annual NOx emissions from the facility by 10,550 tpy, and that the addition of SNCR to Units 1 & 4 would result in total NOx emission reductions of 12,989 tpy.[15]

This reasonable progress Four-Factor Analysis evaluates the technical feasibility, effectiveness, and costs of NOx control technologies available to reduce emissions from SJGS Units 1 & 4 equipped with LNB/OFA/NN and SNCR. The units currently achieve a baseline NOx emission rates of 0.223 and 0.226 lb./MMBtu (annual average), respectively, approximately 25% below the 2013 BART determination baseline of 0.30 lb./MMBtu.

5.1.2 Technical Feasibility of Available NO_X Control Options

Section B.4.h of the 2019 EPA Guidance Document ("*Reliance on previous analysis and previously approved approaches*") notes that in order to satisfy the requirement for documentation in section 51.308(f)(2)(iii)[16] of the Regional Haze Rule, "a state that is referencing and relying on a previous analysis could explain why it concludes that the previous analysis does not require an update." The EPA Guidance Document states that "[i]t may be appropriate for a state to rely on a previous BART analysis or reasonable progress analysis for the characterization of a factor, for example information developed in the first implementation period on the availability, cost, and

[13] See, Best Available Retrofit Technology Analysis Addendum, prepared by Black & Veatch for PNM San Juan Generating Station, April 2013.

[14] See, New Mexico Environment Department Air Quality Bureau, Revised BART Determination, Public Service Company of New Mexico San Juan Generating Station Units 1 and 4, revised June 27, 2013 ("NMED 2013 BART Determination").

[15] NMED 2013 BART Determination, pg. 44.

[16] 40 CFR 51.308(f)(2)(iii) states that: "The State must document the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress in each mandatory Class I Federal area it affects."

effectiveness of controls for a particular source, if the previous analysis was sound and no significant new information is available."

The 2013 BART Assessment included a comprehensive evaluation of NOx control technologies available to SJGS. The following subsections reexamine technical information included in the 2013 BART Assessment, and associated documents, and review each control technology option for applicability to SJGS Units 1 & 4 and for significant new information regarding technology improvements or advances in the commercial development of a technology. In addition, the fact that SJGS Units 1 & 4 are currently equipped with post-combustion SNCR is taken into consideration, as SNCR may affect the technical feasibility of certain control options.

5.1.2.1 Combustion Controls: Low NO_x Burners, Overfire Air with Neural Network

Combustion control systems are designed to optimize combustion parameters and limit NOx formation. NOx, consisting primarily of NO and NO_2, is formed during combustion by two primary mechanisms: thermal NO_x and fuel NO_x. Thermal NO_x results from the dissociation and oxidation of nitrogen in the combustion air, and is dependent on oxygen availability during the combustion process and combustion temperatures. Fuel NOx results from the oxidation of nitrogen organically bound in the fuel. Fuel NOx is the dominant NOx producing mechanism in the combustion of pulverized coal, and typically accounts for 75% to 80% of total NOx emissions.

The 2013 BART Assessment included a detailed description of available combustion control technologies, including LNB, OFA, and NN. In general, LNB combustion systems are designed to stage combustion and control the air-to-fuel ratio and mixing, thereby reducing oxygen availability and controlling combustion temperatures in the ignition and main combustion zones. OFA is designed to reduce excess combustion air in the primary combustion zone to reduce combustion temperatures and thermal NOx formation, with the remaining (overfire) air added higher in the furnace to complete combustion. NN control systems reduce combustion-related emissions by fine-tuning the combustion processes.

Combustion controls, including LNB/OFA and NN combustion optimization control systems were determined to be technically feasible NOx control technologies, and, in fact, SJGS Units 1 & 4 are currently equipped with LNB/OFA/NN. These controls systems were installed on the units for NOx control prior to the initial planning period, and effectively reduced NOx emissions to approximately 0.30 lb./MMBtu, the baseline NOx emission rate used in the 2013 BART determination.

5.1.2.2 Selective Non-Catalytic Reduction

The 2013 BART Assessment included an evaluation of the technical feasibility and effectiveness of SNCR. SNCR control systems are designed to reduce NOx emissions by injecting a reagent at multiple locations in the boiler. SNCR systems can use either ammonia (NH_3) or urea as the reagent. The reagent is injected into the boiler where it reacts with NOx (NO and NO_2) to form nitrogen (N_2) and water. Flue gas temperatures of 1,500 to approximately 2,200°F, and a residence time of at least 0.3 seconds within the optimum temperature range, are required to support reaction kinetics without using a catalyst and to ensure adequate SNCR performance. SNCR systems rely solely on reagent injection (rather than a catalyst) and an appropriate reagent injection temperature, good reagent/gas mixing, and adequate reaction time to achieve NOx reductions. To accommodate SNCR reaction temperature and boiler turndown requirements, several levels of injection lances may be required.

The 2013 BART Assessment concluded that SNCR was a technically feasible NOx control option for SJGS, and, in fact, SNCR coupled with the retirement of SJGS Units 2 & 3 was determined to represent BART. The final New Mexico Regional Haze SIP, approved by EPA on October 9, 2014, required the installation of SNCR on Units 1 & 4 and a controlled NOx emission limit of 0.23 lb./MMBtu. Since installing SNCR, SJGS Units 1 & 4 have achieved controlled NOx emission rates of 0.223 lb./MMBtu and 0.226 lb./MMBtu, respectively, on a 12-month annual average. These emission rates represent baseline NOx emissions for the Four-Factor Analysis.

5.1.2.3 Selective Catalytic Reduction

SCR is a process by which ammonia (NH_3) reacts with nitrogen oxide (NO) and nitrogen dioxide (NO_2), collectively NO_X, in the presence of a catalyst to reduce the NOx to nitrogen (N_2) and water (H_2O). SCR technology has been applied on coal-fired steam electric generating units burning various types of coal, including bituminous and subbituminous coals. The principal reactions resulting in NO_X reduction are:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$4NO_2 + 8NH_3 + 2O_2 \rightarrow 6N_2 + 12H_2O$$

Because these reactions proceed slowly at typical boiler exit gas temperatures of a coal-fired steam electric generating unit, a catalyst is used to increase the reaction rate between NOx and NH_3. Depending on the specific constituents in the flue gas, a typical temperature range of 550°F to 780°F is necessary to achieve normal performance of the catalyst. For the typical coal-fired boiler, optimal performance will be in the range of approximately 650°F to 750°F.

The SCR reactor is located in the flue gas stream between the economizer outlet and the air preheater inlet. This configuration locates the SCR within the inherently optimal temperature range for NOx reduction; however, flue gas characteristics at the economizer outlet can also have detrimental effects on the SCR catalyst. SCR catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is caused by either exposure of the catalyst to excessive temperatures (thermal deactivation) or masking of the catalyst due to entrainment of particulate from the flue gas stream (fouling). Chemical deactivation is caused by either an irreversible reaction of the catalyst with a contaminant in the gas stream (poisoning) or a reversible absorption of a contaminant on the surface of the catalyst (inhibition). Loss of catalyst activity through thermal degradation or poisoning is permanent, and reactivity can only be restored by replacing the catalyst. On units such as SJGS Units 1 & 4 that are equipped with baghouse particulate control systems, the SCR must be designed to minimize adverse effects of high dust loading which can expose the SCR catalyst to excessive erosion and fouling. High levels of fly ash can result in significant erosion of the catalyst, resulting in more frequent cleaning cycles and catalyst replacement.

SCR, including high-dust SCR, has been installed on numerous coal-fired steam electric generating units and has demonstrated the ability to effectively reduce NOx emissions. Numerous design/operating factors must be evaluated to determine the effectiveness, installation costs, and operating costs when retrofitting SCR onto an existing units. Design/operating factors include, but are not limited to, fuel characteristics, boiler operating conditions, flue gas temperatures, fly ash loading and characteristics, existing pollution control systems, space constraints and site constructability issues. However, SCR is considered a technically feasible NOx control option for SJGS Units 1 & 4. Based on emissions achieved in practice, anticipated vendor guarantees, and engineering judgment, SCR will be evaluated at an average NOx emission rate of 0.05 lb./MMBtu.

5.1.2.4 Alternate NOx Control Technologies

In addition to combustion controls, SNCR, and SCR, the 2013 BART Assessment included an evaluation of other potentially feasible NOx control technologies. Alternative NOx control technologies evaluated as part of the BART determination process included gas reburn, Mobotec's ROFA and Rotamix systems, NOxStar, ECOTUBE, PowerSpan, Phenix Clean Combustion, e-SCRUB, and PerNOxide. These technologies were evaluated and eliminated from consideration as BART, based on technical infeasibility, effectiveness (i.e., less effective than other alternatives), commercial availability, limited actual practice on similarly sized-units, or cost-effectiveness. A brief description of each technology, and a reexamination of the technical information used in the 2013 BART Assessment is provided below.

5.1.2.4.1 Gas Reburn

The gas reburn process employs three separate combustion zones to reduce NOx emissions. The first zone consists of the normal combustion zone in the lower furnace, where approximately 75 to 80% of the total fuel heat input is introduced with approximately 10% excess air. A second combustion zone (the reburn zone) is located above the lower furnace by operating a row of conventional natural gas burners at a stoichiometric ratio of less than 1.0. The sub-stoichiometric reburn zone causes NOx produced in the lower furnace to be reduced to molecular nitrogen and oxygen. Fuel burnout is completed in the third zone (the burnout zone) by the introduction of OFA. Residence time in the reburn and OFA zones (i.e., adequate furnace height) is a key factor in determining the technical feasibility and effectiveness of this technology. Gas reburn technology requires space within the boiler to allow adequate residence time for both the additional burning zone (0.4 to 0.6 seconds) and the associated OFA burnout zone (0.6 to 0.9).[17] Lower residence times limit system performance.

In addition to conventional gas reburn control system design, the 2013 BART Assessment identified two gas reburn variations: fuel lean gas reburn (FLGR) and amine-enhanced FLGR (AE-FLGR). FLGR technology utilizes lower natural gas flow rates in the primary combustion zone to maintain overall lean fuel condition and reduce NOx formation. This design requires a lower natural gas input than in a conventional gas reburn system. AE-FLGR involves injecting natural gas and urea into the combustion zone to reduce NOx formation and achieve additional NOx reductions through urea-based reactions (identical to SNCR). As with conventional gas-reburn systems, FLGR and AE-FLGR, sufficient space/residence time is needed for the control systems and adequate fuel/gas mixing is required for effective NOx control.

The 2013 BART Assessment determined that natural gas reburn technologies were not technically feasible NOx control options for SJGS because of the lack of space in the boiler for sufficient residence time for the natural gas reburn zone. As currently configured, the evaluation concluded that there is only about 0.25 second of residence time for a fuel gas reburn system. The BART evaluation considered the option of moving the existing OFA ports up to provide more residence time for the gas reburn zone; however, the evaluation concluded that this approach would decrease the effectiveness of OFA by inhibiting the mixture of the over-fired air. In addition, the BART determination concluded that a new natural gas supply line would be required to implement the control system. NMED accepted elimination of this technology due to space limitations.[18]

[17] See, 2013 BART Assessment, pg. 3-10.

[18] NMED 2013 BART Determination, pg. 11

Sargent & Lundy reviewed the 2013 BART Assessment and considers the analysis complete and technically sound. Further, Sargent & Lundy is not aware of any significant new information or technical advances that would affect the technical feasibility of gas reburn on SJGS Units 1 & 4, as the boiler configurations still lack space for sufficient residence time and a new natural gas supply would still be required, as currently there is no gas supply to the station. For these reasons, gas reburn was eliminated from further consideration in the Four-Factor Analysis.

5.1.2.4.2 Mobotec ROFA and Rotamix

The 2013 BART Assessment included an evaluation of one NOx reduction system that combines LNB/OFA: Rotating Opposed Firing Air (ROFA); and one technology that combines LNB/OFA and SNCR technologies into an integrated system: Rotamix. ROFA and Rotamix are proprietary control technologies developed by Nalco Mobotec. ROFA uses a booster fan to direct combustion air away from the primary combustion zone and to the upper portion of the furnace. Air nozzles are used to create turbulent mixing by adding a rotation to the OFA. The combustion system is designed to lower NOx formation in the primary combustion zone and improve combustion in the upper portion of the furnace. Rotamix consists of injecting urea or ammonia into the ROFA air nozzles. Rotamix is a version of SNCR technology that operates under the same principles as other SNCR technology. The system is designed to provide additional NOx reductions by creating additional residence time within the required temperature profile.

The 2013 BART Assessment concluded that ROFA and Rotamix technologies were not technically feasible at SJGS based on the finding that there were no current installations at pulverized coal fired boilers of equivalent size to that of SJGS. The BART evaluation also noted that the ROFA technology is a variation of OFA, which has already been installed on the SJGS boilers. Based on the limited large-scale experience with the Rotamix system, the 2013 BART Assessment concluded that ROFA/Rotamix were not technical feasible or available NOx control options for SJGS.

NMED did not agree that because ROFA is a variant of OFA, the technology can be eliminated as technically infeasible. Therefore, NMED requested that PNM perform the complete 5-factor analysis for ROFA and Rotamix. At NMED’s direction, both ROFA and Rotamix were carried through the complete 5-step BART process, including an evaluation of costs and cost-effectiveness. ROFA was evaluated at a controlled NOx emission rate of 0.26 lb./MMBtu and Rotamix was evaluated at 0.23 lb./MMBtu (i.e., the same emission rate as SNCR). Although the cost-effectiveness of both technologies was found to be similar to that of SNCR (with the exiting OFA system), NMED found that Rotamix was a variant of SNCR and determined that BART required the installation of SNCR on Units 1 & 4.

Sargent & Lundy reviewed the 2013 BART Assessment and NMED's BART determination, and considers the analyses complete and technically sound. Further, Sargent & Lundy is not aware of any significant new information or technical advances that would affect the technical feasibility of ROFA or Rotamix on SJGS Units 1 & 4. As noted above, SJGS Units 1 & 4 are currently equipped with OFA and SNCR, and replacing the existing OFA/SNCR systems with Rotamix is not expected to provide any additional NOx control beyond that achieved with the existing controls. Furthermore, Sargent & Lundy is not aware of more recent Rotamix control systems installed on coal-fired boilers similar in size to SJGS Units 1 & 4. Thus, replacing the existing controls with Rotamix would incur additional costs while providing no further reductions in NOx emissions. For these reasons, retrofit ROFA/Rotamix would have no practical application on units that are already equipped with OFA/SNCR and not considered technically feasible NOx control options for SJGS Units 1 & 4. Therefore, the technologies were eliminated from further consideration in the Four-Factor Analysis.

5.1.2.4.3 NOxStar

NOxStar was described in the 2013 BART Assessment as follows:

> *NOxStar is the trademarked name for a NOx control technology provided by Doosan Power Systems (formerly Mitsui Babcock). It involves the injection of ammonia and a hydrocarbon (typically natural gas) into the flue gas path of a coal fired boiler at around 1,600 to 1,800° F for the reduction of NOx. The ammonia reduces NOx through an SNCR reaction, with the hydrocarbon minimizing the ammonia slip. This enables higher reagent injection rates for NOx reductions than are achievable with a typical SNCR technology… Although initially targeting high NOx reductions, full-scale demonstrations to date have been limited to nominally 50 percent NOx reduction performance.*

The 2013 BART Assessment concluded that NOxStar was not a technically feasible option for NOx control at SJGS because, at the time of the BART determination, the technology had only one major installation in the U.S., and that the technology may require the installation of a single layer of in-duct catalyst to achieve the advertised levels of NOx reduction. In addition, discussions with the supplier identified a limited ability and willingness to market the technology. Finally, as with the gas reburn option, nature gas is not currently available at the San Juan station to support the technology. Based on these limitations, the BART determination concluded that NOxStar was not a technically feasible or commercially available control option for SJGS. NMED agreed that this technology had limited application to large coal-fired boilers and was not a technically feasible option for SJGS.[19]

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[19] *Id.*, at pg. 12

Sargent & Lundy reviewed the 2013 BART Assessment and considers the analysis complete and technically sound. Further, Sargent & Lundy is not aware of any significant new information or technical advances that would affect the technical feasibility or applicability of NOxStar on SJGS Units 1 & 4. In addition, a new natural gas supply would still be needed to support the technology. For these reasons, NOxStar was eliminated from further consideration in the Four-Factor Analysis.

5.1.2.4.4 ECOTUBE

The 2013 BART Assessment included an evaluation of the ECOTUBE NOx control system. The ECOTUBE system utilizes retractable lance tubes that penetrate the boiler above the primary burner zone and inject high-velocity air, as well as reagents. The lance tubes work to create turbulent airflow enhance air/fuel/reagent mixing. Similar to Rotamix, the ECOTUBE system combines OFA and SNCR control principles. The BART assessment noted that this technology had only been demonstrated in installations on industrial/small-sized boilers firing solid waste, wood, or biomass, and had not been applied to large coal-fired boilers. As such, it was concluded that the ECOTUBE technology was not a technically feasible or commercially available control option for SJGS. NMED agreed that the technology has limited application to boilers similar to Units 1-4 at the SJGS; thus, NMED agreed that ECOTUBE was not a technically feasible option.[20]

Sargent & Lundy reviewed the 2013 BART Assessment and considers the analysis complete and technically sound. Further, Sargent & Lundy is not aware of any significant new information or technical advances that would affect the technical feasibility, commercial availability or applicability of the ECOTUBE technology on SJGS Units 1 & 4. For these reasons, ECOTUBE was eliminated from further consideration in the Four-Factor Analysis.

5.1.2.4.5 PowerSpan ECO

The 2013 BART Assessment included an evaluation of the PowerSpan ECO system (ECO). The ECO system is designed to be located downstream of the unit's particulate control device; and consists of three stages described in the BART assessment as follows:

> *In the first stage, the flue gas passes through a dielectric barrier discharge reactor, where it is exposed to a nonthermal plasma discharge, which generates high energy electrons. The electrons initiate a chemical reaction to form oxygen and hydroxyl radicals, which then oxidize NOx, SO_2, and Hg. This process results in the formation of nitric acid (HNO_3), sulfuric acid, and*

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[20] *Id.*

mercuric oxides. Stage 2 is the collection of these acids and oxides in a downstream ammonia scrubber. The final stage is the collection of acid aerosols, fine PM, and oxidized Hg in the downstream wet ESP.

The 2013 BART Assessment noted that the ECO system had only been demonstrated on a small scale (i.e., 1-2 MW equivalent slip stream), and that the process had not been applied at large-size commercial systems such as SJGS. As such, it was concluded that the process was not a technically feasible and commercially available NOx control option at SJGS. NMED agreed that this technology had limited application to large coal-fired boilers and was not technically feasible at SJGS.[21]

Sargent & Lundy reviewed the 2013 BART Assessment and considers the analysis complete and technically sound. Further, Sargent & Lundy is not aware of any significant new information or technical advances that would affect the technical feasibility of the ECO multi-pollutant control system on SJGS Units 1 & 4. Sargent & Lundy is not aware of any installations of the control technology on large coal-fired boilers that would establish technical feasibility and effectiveness, and is not aware of additional demonstration tests establishing that the technology has advanced beyond the development stage. For these reasons, the gas reburn was eliminated from further consideration in the Four-Factor Analysis.

5.1.2.4.6 Phenix Clean Coal Combustion System

The 2013 BART Assessment noted that a previous BART study prepared for SJGS in 2007 included an evaluation of Phenix Limited LLC's Clean Combustion System (CCS) as a potential control technology, but noted that since the 2007 study, Phenix Limited LLC had ceased operating and that the technology had never moved beyond the demonstration and testing stages. NMED agreed that this technology had no demonstrated application to large coal-fired boilers and was therefore not considered to be applicable for retrofit at SJGS.[22]

Sargent & Lundy reviewed the 2013 BART Assessment and considers the analysis complete and technically sound. Further, Sargent & Lundy is not aware of any significant new information that would change the conclusion that the Phenix CCC control system is a technically feasible or commercially available option for SJGS. Thus, the CCC control systems was eliminated from further consideration in the Four-Factor Analysis.

[21] *Id.*

[22] *Id.*

5.1.2.4.7 e-SCRUB

The 2013 BART Assessment also noted that the 2007 SJGS BART study identified the e-SCRUB process as a potential control technology, but noted that e-SCRUB had subsequently ceased operating and that the technology could no longer be considered to be commercially available. The BART assessment noted that, similar to the PowerSpan technology, the e-SCRUB technology used an energy source to oxidize pollutants in the flue gas with some variations in the oxidation energy source and byproduct recovery systems. However, the technology was eliminated from consideration as BART because it was still an experimental system and no longer commercially available. NMED noted in its BART determination for SJGS that the e-SCRUB technology was still an experimental system with only one known medium scale installation with limited data, and agreed that the technology should be considered technically infeasible due to limited demonstrated applications.[23]

Sargent & Lundy reviewed the 2013 BART Assessment and considers the analysis complete and technically sound. Further, Sargent & Lundy is not aware of any significant new information or technical advances that would affect the technical feasibility or commercial availability of the e-SCRUB multi-pollutant control system on SJGS Units 1 & 4. Sargent & Lundy is not aware of any installations of the control technology on large coal-fired boilers that would establish technical feasibility and effectiveness, and is not aware of additional demonstration tests establishing that the technology has advanced beyond the development stage. For these reasons, the e-SCRUB technology was eliminated from further consideration in the Four-Factor Analysis.

5.1.2.4.8 PerNOxide

The 2013 BART Assessment included an evaluation of the PerNOxide technology provided by FMC Environmental Solutions in conjunction with URS. The PerNOxide system injects hydrogen peroxide into the flue gas somewhere between the economizer and the air preheater where the hydrogen peroxide evaporates and oxidizes NO to form NO_2, N_2O_5, HNO_2, and HNO_3. The new compounds are significantly more soluble than NO and can be removed from the flue gas in a downstream wet FGD. The BART assessment noted, however, that the PerNOxide system had gone through numerous bench scale tests and a full-scale pilot test, but there are no commercial installations at that time. Because the technology remained in the testing/developmental stage, and there were no commercial installations, the technology was not considered to be applicable for retrofit at SJGS.

23 *Id.*

Sargent & Lundy reviewed the 2013 BART Assessment and considers the analysis complete and technically sound. Further, Sargent & Lundy is not aware of any significant new information or technical advances that would affect the technical feasibility or commercial availability of the PerNOxide control system on SJGS Units 1 & 4. Sargent & Lundy is not aware of any installations of the control technology on large coal-fired boilers that would establish technical feasibility and effectiveness, and is not aware of additional demonstration tests establishing that the technology has advanced beyond the development stage. For these reasons, the PerNOxide control system was eliminated from further consideration in the Four-Factor Analysis.

5.1.2.4.9 Hybrid SNCR/SCR

The 2013 BART Assessment included an evaluation of a hybrid SNCR/SCR system. In general, hybrid SNCR/SCR systems use components and operating characteristics of both SNCR and SCR systems. SNCR components of the system would essentially be identical to the SNCR system described above and currently installed on SJGS Units 1 & 4, except that modifications to the existing system would likely be needed to support increased reagent (i.e., urea) injection rates. During operation, higher quantities of urea would be injected into the boiler to achieve higher NOx removal rates with higher ammonia slip. Ammonia slip from the SNCR is then used as the reagent for the downstream SCR catalyst.

As described in the 2013 BART Assessment, there are two general design philosophies for hybrid SNCR/SCR systems. The first, approach uses the catalyst primarily to remove excess ammonia slip while providing some additional NOx reduction. This approach allows for increased NOx removal in the boiler by the SNCR and may allow for an in-duct catalyst arrangement with no significant ductwork changes or structural modifications. The second approach incorporates adequate catalyst volume to achieve overall NOx reductions similar to those achieved with a more traditional SCR arrangement. However, as noted in the 2013 BART Assessment, this approach typically requires significant flue gas path modifications and provides no economic advantages when compared to SCR as the equipment design of the hybrid system would be similar to the design of an SCR. Because the second hybrid SNCR/SCR approach provides no technical or economic advantages compared to SCR it was eliminated from consideration as BART.

The hybrid SNCR/in-duct SCR option was determined to be a technically feasible NOx control option in the 2013 BART Assessment; thus, the technology carried through the 5-step BART evaluation process, but was ultimately excluded from BART based on costs and cost-effectiveness. The technology was evaluated at a controlled NOx emission rate of 0.18 lb./MMBtu, compared to 0.23 lb./MMBtu with SNCR alone, and was determined to have an average cost-effectiveness of $10,154/ton (Unit 1) and $10,226/ton (Unit 4), compared to approximately $5,600/ton from SNCR.[24] It is important to note that this option was reviewed in 2013 when both units were equipped with hot electrostatic precipitator (HESP) particulate controls systems. The HESP control systems would have provided a relatively particulate-free flue gas at the inlet to an in-duct SCR, which, based on flue gas temperatures, would have been located downstream of the HESP. However, the HESPs are no longer in operation and have been replaced with PJFF baghouse particulate control systems located downstream of each units' air preheaters and downstream of where an in-duct SCR would be located. Flue gas flow though the abandoned HESPs has been reconfigured, and significant engineering would be required to rebuild and reinstall the HESP equipment while providing no further reductions in particulate matter emissions. As such, it would be impractical for SJGS to reinstall the HESPs to provide low-particulate flue gas upstream of an in-duct SCR.

Sargent & Lundy reviewed the 2013 BART Assessment and considers the analysis complete and technically sound; however, based on a review of the design/operation of SJGS Units 1 & 4, there are a number of technical issues that would have to be evaluated to establish the technical feasibility of a hybrid SNCR/in-duct SCR control system on SJGS Units 1 & 4 equipped with PJFF baghouses. First, in order to be within the required temperature window for effective NOx reduction, the catalyst layers would have to be located between the economizer and air preheater inlet on each unit. Flue gas velocities in this location would be in the range of 50-60 fps, compared to catalyst design criteria of approximately 20 fps. Therefore, even for the in-duct SCR arrangement, ductwork downstream of the economizer would have to be expanded to achieve the required flue gas velocities, and subsequently reduced prior to the inlet to the air preheater. Second, because the catalyst would be located upstream of the particulate control device on each unit, the catalyst would have to be located in a vertical section of ductwork. Given the high ash concentration in the flue gas, and the fact that flue gas velocity must be reduced through the catalyst, locating the catalyst in a horizontal section of ductwork would result in unacceptable ash fall out and catalyst plugging. Because the catalyst must be located in a vertical section of ductwork, and because the ductwork must be expanded to achieve required velocities through the catalyst, it is very likely that the flow gas path downstream of the economizer would require significant modifications including a riser duct to allow for downward flow through catalyst and adequate space for ductwork expansion, catalyst housing, and ductwork reduction.

Third, as described in the 2013 BART Assessment, the in-duct SCR system can have significant adverse impacts on the air preheater. One concern is the formation and deposition of ammonium bisulfate on air preheater surfaces, which would cause an increase in the pressure drop through the air preheater, degrading its performance and

[24] *Id.*, at pg. 17, Table 10

decreasing plant efficiency. The other potential concern for the air preheater is high concentrations of sulfur trioxide (SO_3) in the flue gas. If flue gas temperatures fall below the acid dew point, acid gases will condense in the air preheater and lead to plugging and corrosion. Modifications to the air preheater baskets would likely be required to mitigate these potential adverse effects.

Finally, any additional NOx reduction achieved with the hybrid SNCR/in-duct SCR design will be a function of the quantity of reagent injected into the boiler, ammonia slip, catalyst volume (which may be limited due to space constraints), and distribution of ammonia-to-NOx within the flue gas. Increasing reagent injection into the boiler would likely require installation of additional injection lances and modifications to the existing SNCR system to support increased reagent injection rates. In addition, the in-duct arrangement would not allow for optimal ammonia distribution and flue gas mixing; thus, using ammonia slip produced by the SNCR system is not an efficient method to introduce reagent into the flue gas.

Ductwork modifications required for the hybrid SNCR/in-duct SCR system, air preheater modifications, and upgrades/modifications to the existing SNCR system would minimize or eliminate any potential economic advantage of the hybrid system compared to a more conventional SCR. In addition, Sargent & Lundy is not aware of this combination of control technologies being used or demonstrated on large coal-fired boilers such as SJGS Units 1 & 4, and the facility would likely incur significant time and expense engineering and evaluating the system to determine the technical feasibility, potential effectiveness, costs, and balance-of-plant impacts associated with the control system. Because the combination of SNCR/in-duct SCR would require significant engineering/evaluation and significant duct modifications in a high-dust configuration, and because the system has not been demonstrated in practice at similarly sized coal-fired boilers, the hybrid SNCR/in-duct control system is not considered an available NOx control technology for SJGS Units 1 & 4 and will not be evaluated further in the Four-Factor Analysis.

5.1.3 Evaluate Technically Feasible NO_X Control Option for Control Effectiveness

Based on a review of physical, chemical, and engineering principles, and an assessment of NOx control technologies installed on existing coal-fired boilers, as well as operational practices and equipment upgrades implemented on SJGS Units 1 & 4, the only potentially available option to further NOx control on SJGS Units 1 & 4 is replacing the existing SNCR control system with SCR. Other potentially available NOx control technologies, such as ROFA/Rotamix would not be expected to achieve additional NOx reduction beyond that achieved with the exiting SNCR control system. Innovative NOx control technologies, and multi-pollutant control technologies, have not developed beyond demonstration, have not been demonstrated on large coal-fired boilers, or are not commercially available. Similarly, the hybrid SNCR/in-duct SCR would pose significant engineering and design challenges to determine technical feasibility and effectiveness on SJGS Units 1 & 4, and the technology has not been demonstrated on a large coal-fired boiler and is therefore not an available NOx control technology. These findings are consistent with conclusions drawn during the 2013 BART determination process.

Technically feasible NOx control technologies, and projected controlled emission rates, are listed in Table 5-1. Emission rates shown in Table 5-1 represent annual average emission rates that the control options would be expected to achieve during normal operations and the corresponding reduction in annual emissions.

Table 5-1. Technically Feasible NOx Control Options for SJGS Units 1 & 4

	Unit 1		Unit 4	
Baseline 2028 Annual Heat Input (MMBtu/yr)	27,946,940		41,223,071	
Control Technology	**lb./MMBtu**	**tpy**	**lb./MMBtu**	**tpy**
Baseline (LNB/OFA/SNCR)	0.233	3,116	0.226	4,658
SCR	0.05	699	0.05	1,031
Annual Emission Reductions	--	2,417	--	3,627

Note 1. Emission rates shown above represent average emissions that each control option would be expected to achieve on an ongoing long-term basis under normal operating conditions. Emission rates are provided for comparative purposes only and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control-system-specific basis, and additional compliance margin would likely be needed to account for all operating conditions.

5.2 EVALUATE STATUTORY FACTORS - NO_X CONTROL

As discussed in Section 1, the four statutory factors are: (1) cost of compliance; (2) time necessary for compliance; (3) energy impacts and non-air quality environmental impacts; and (4) remaining useful life of the affected source. This section applies the four-factors to the technically feasible NOx control options identified in Section 5.1.1.

5.2.1 Cost of Compliance

5.2.1.1 Cost Estimating Approach

The economic evaluation performed as part of the Four-Factor Analysis examines the cost-effectiveness of each technically feasible control technology, on a dollar per ton of pollutant removed basis. Annual emissions, calculated for a particular control device, are subtracted from baseline annual emissions to calculate tons of pollutant removed by the control technology on an annual basis. For units with existing controls, such as SJGS Units 1 & 4, the base case represents existing baseline actual emissions. Annual costs for each control option are calculated relative to the base case by adding annual operations and maintenance (O&M) costs to the annualized cost of capital and, if applicable, lost revenue due to extended outage required for installation of the control equipment. For this evaluation, capital costs of the SCR control system and lost revenues are annualized using a capital recovery factor based on an annual interest rate of 7% and two alternative equipment lives: (1) 7-years assuming facility operations cease in 2035 (see, Section 5.2.4); and (2) an equipment life of 20-years assuming operations extend beyond 2048. Cost effectiveness ($/ton) is simply the total annual cost ($/yr.) divided by the annual reduction in emissions (ton/yr.).

Capital and O&M cost estimates were developed for the technically feasible NOx control options. Cost estimates represent scoping level estimates. As such, Sargent & Lundy did not obtain equipment quotes specifically for the SJGS units. Rather, equipment costs are based on conceptual designs developed for the retrofit control systems, site specific constraints, preliminary equipment sizing developed for the major pieces of equipment based on SJGS Unit 1 & 4 specific design parameters (including typical fuel characteristics, full-load heat input and flue gas temperatures and flow rates), and recent pricing for similar equipment or scaled cost estimates prepared by Sargent & Lundy for other similar projects.

Major equipment costs were developed based on equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit the units with the control technology. Sub-accounts for the capital cost estimates (e.g., mobilization and demobilization, consumables, contractor general and administration (G&A) expense, freight on materials, etc.) were developed by applying ratios from detailed cost estimates that were prepared for projects with similar scopes.

The cost estimates for the SJGS Unit 1 & 4 retrofit technologies are conceptual level cost estimates. The American Association of Cost Engineers (AACE) categorizes cost estimates by the “degree of project definition.” Conceptual level costs estimates (AACE Level 5) are defined as “concept screening” cost estimates generally based on parametric models, judgment, or analogy. As described above, cost estimates prepared for this Four-Factor Analysis were developed based on conceptual layouts of the control systems, equipment costs factored from similar projects, engineering calculations, and engineering judgment.

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent, water consumption, and auxiliary power requirements. Auxiliary power requirements reflect the additional power requirements associated with the operation of the new control technology (compared to the existing technology). All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing NOx control systems.

5.2.1.2 SJGS Unit 1 & 4 SCR Cost Estimating Assumptions

SJGS Unit 1 & 4 SCR cost estimates include identical SCR systems, adjusted for their respective flue gas flow rate. Capital costs are generally based on cost estimates prepared for the 2011 BART evaluation, modified based on changes to the facility since that time (e.g. balanced draft conversion and installation of BJFF baghouses) and escalated to 2020-dollars assuming 3% annually on material, equipment, and labor. Based on a site-specific review of the NOx reduction requirements and retrofit challenges associated with the installation of SCR control systems at SJGS, the following project-specific issues were taken into consideration in the development of the SCR cost estimates:

- <u>SCR Location</u>. The proposed SCR reactors will be located above the existing air preheaters. Ductwork from the economizer outlet to the air preheater inlet will be replaced. The decommissioned electrostatic precipitator on Unit 4 will be demolished. Galleries will be provided at each catalyst level, at the ammonia injection grid level and at the ash handling levels to allow for maintenance and inspection of the SCR system.

- <u>SCR Reactors</u>. The conceptual design calls for a single reactor for Unit 1 and two reactors for Unit 4. Each reactor will have slots for four layers of catalyst (three layers plus a spare) and will use anhydrous ammonia as the reagent.

- <u>Economizer Bypass</u>. Based on SJGS coal parameters, an economizer outlet temperature of at least 580°F is required for proper operation of the SCR. If flue gas flowing through the SCR is less than 580°F, ammonia cannot be injected into the SCR and catalyst reactivity will be reduced. For periods of operation when the economizer outlet temperature is less than 580°F, a means to increase the outlet temperature must be included in the SCR design. A water-side bypass in the economizer has been used on other recent SCR installation projects to increase the economizer outlet temperature, and a similar low-load temperature control system is needed on the SJGS units to allow low-load operation and unit cycling. Thus, economizer bypass costs were included in the cost estimate for the SJGS SCRs.

- <u>Demolition of the Existing Hot-Side ESPs</u>. Demolition of the existing Unit 4 HESP is needed to fit the retrofit SCR control systems into the available space. The configuration of the SCR control system requires that it be placed above the existing air heater. Due to the height of the ductwork leading to the air heater, the top of the SCR, as designed, is already approaching the top of the boiler building. If this height is exceeded, impacts on the existing chimney and plume dispersion would need to be evaluated. As designed, the bottom of the inlet duct to the SCR runs at the same elevation as the top hot-side precipitator, necessitating removal of the existing precipitator housing. Reusing the existing ductwork was evaluated and found not to be acceptable due to the increase in flue gas velocity. We also evaluated using the top hot-side precipitator as a duct, but again the degradation of the equipment and flue gas velocities would not support the design. This cost is not included on Unit 1, due to the station having recently demolished the upper box of the HESP as part of the HESP bypass project on Unit 1.

- Catalyst Layers. To achieve the required NOx emission reductions on a consistent basis with ultra-low SO_2 to SO_3 conversion catalyst, three layers of catalyst, rather than the two layers specified for other similar projects, would be required for the SJGS SCRs. The SJGS SCRs would be designed to hold four layers of catalyst, with three layers being loaded initially. The additional layer of catalyst is needed to meet an enforceable NOx emission limit of 0.05 lb./MMBtu, which could not be met with two layers. The fourth layer of catalyst would be added to the SCR after approximately two years of operation. Furthermore, the ash content of the coal used at SJGS results in increased costs for the catalyst, as well as increased complexity and costs of the ash handling systems.

- Air Preheater Modifications. Based on the temperatures expected for the SCR operation, it can be expected that the ammonia and SO_3 in the flue gas will react to form ammonium bisulfate (ABS) in the intermediate section of the air preheaters. The facility has experienced ABS fouling since the installation of the SNCR and has installed ceramic coating on baskets on Unit 4's air preheater; however, an SCR system is expected to operate with a much lower ammonia slip level at the air preheater inlet. Therefore, no costs were included for additional air preheater modifications.

- SCR Catalyst Replacement. An elevator was included in the SCR cost estimate to replace spent catalyst at the end of the catalyst life.

- Sootblowers on SCR. The method of cleaning the fly ash that settles on the catalyst is extremely important to obtain the guaranteed life of the catalyst. For this reason, the use of steam sootblowers, in addition to sonic horns, is recommended for the SJGS units. Steam sootblowers will remove fly ash that settles on the catalyst and the sonic horns will keep the fly ash moving through the catalyst. Air sootblowers were also considered but, due to the high loss on ignition (LOI) at the plant, were determined to be a potential fire hazard. The top layer of catalyst will be provided with steam sootblowers. The balance of the catalyst layers will be cleaned using sonic horns. This system will require compressed air to operate. A separate compressor for each unit was assumed for the cost estimate.

- Large Particle Ash Screen. To collect the maximum amount of fly ash at the economizer hopper, a large particle ash screen will be installed at the exit of the economizer. This ash screen will be used to divert larger fly ash particles that can plug the SCR catalyst into the economizer ash hoppers. This may also eliminate the need for additional fly ash systems at the SCR inlet and outlet ductwork.

- Dry Sorbent Injection. The SCR will increase the formation of SO_3 and sulfuric acid mist (SAM) loading to downstream equipment. SO_2 to SO_3 conversion is increased by approximately 0.5% with the SCR. To meet the units' existing SAM emission limit when operating without carbon capture requires installation and operation of a DSI control system. This approach is consistent with assumptions in the 2013 BART Assessment. Therefore, costs for a DSI control system were included in the SCR cost estimate.

- Anhydrous Ammonia System. A common anhydrous ammonia system will be installed centrally to Units 1 & 4. The SCR systems will share ammonia storage, unloading skid and forwarding pumps, but unit specific modulating skids and vaporizers were included in the estimate.

- Structural Stiffening. Structural stiffening of the boiler, ductwork, and equipment downstream of the boiler is typically required to operate the SCR control system and to operate the plant in a balanced draft configuration. Because the balanced draft conversion project has been completed on SJGS Units 1 & 4, these costs were not included in the cost estimate.

- Control Systems. The existing DCS system will need to be expanded to accommodate the additional signals from the SCR system.

- Construction Costs and Special Cranes. A review of the site arrangement shows that the free space between the units is limited due to modifications to the plant with the addition of the baghouses and the coal conveyor running between the units. In order to have the lifting capacity that is required to install an SCR and accommodate the demolition that is required, special cranes are required. Construction difficulty is very high for this very tight site.

- Booster Fan. A booster fan will be required to overcome the additional pressure drop (~10 in. w.c.) from the SCR catalyst. The existing induced draft (ID) fan was installed as part of the balanced draft conversion project and was sized for the existing pressure drop of the system. Booster fans, equipped with VFDs, are required prior to the WFGD to maintain positive pressure through the vessel and were included in the cost estimate.

Other unit-specific factors such as modification of existing systems and site layout required additional unit specific costs are discussed below:

SJGS Unit 1

SJGS Unit 1 is located such that the fabric filters, decommissioned Unit 2, and other structures restrict access directly adjacent to the work area required for SCR installation. This tight configuration creates constructability issues because it limits crane placement and the type of structural foundations that can be added to support the weight of the SCR. Crane placement is important because of the need to build the ductwork over the location of the SCR, which means long lift spans and limited room to assemble and disassemble the cranes. The long spans and limited placement choices limit the crane selection choices to the larger, more expensive cranes.

The tight site configuration also dictates that a more expensive type of deep structural foundations be used. The very low overhead clearances and tight quarters adjacent to the existing stacks, particularly south of the Unit 1 stack where the adjacent fabric filter restricts access to the area, would hamper access during construction and leads to the choice of micropiles for support of the new SCR and ductwork. This construction option is a special type of pile that requires special installation equipment and expertise. The installed cost of this type of pile by a specialty contractor will be high compared to other deep foundation installations, at least double the cost of conventional drilled or driven piles.

SJGS Unit 4

Demolition of the existing hot-side precipitator is needed to fit the retrofit SCR control system into the available space. The configuration of the SCR control system requires that it be placed above the existing air heater. Due to the height of the ductwork leading to the air heater, the top of the SCR, as designed, is already approaching the top of the boiler building. If this height is exceeded, impacts on the existing chimney and plume dispersion would need to be evaluated. As designed, the bottom of the inlet duct to the SCR runs at the same elevation as the top hot-side precipitator, necessitating removal of the existing precipitator. Reusing the existing ductwork was evaluated and found not to be acceptable due to the increase in flue gas velocity. Using the top hot-side precipitator as a duct was also evaluated, but again the degradation of the equipment and flue gas velocities would not support the design.

5.2.1.3 SJGS Unit 1 & 4 SCR Costs and Cost-Effectiveness

Table 5-2 and Table 5-3 present the total capital investment, annualized capital cost, annual operating costs, and total annual costs associated with installing and operating SCR on SJGS Units 1 & 4. As discussed in more detail in Section 5.2.4, capital costs were annualized using two different equipment lives: (1) an equipment life of 7-years based on the assumption that facility operations cease in 2035; and (2) and equipment life of 20-years based on the assumption that operations extend beyond 2048. Table 5-4 show the average annual cost effectiveness for the control system for both scenarios. Additional cost details are provided in Appendix B.

Table 5-2. NOx Control Cost Summary ($2020)
SJGS Units 1 & 4 – Assuming Equipment Life of 20-Years

Unit	NO_X Control Option	Total Capital Investment $	Annual Capital Cost $/yr.	Annual Operating Cost $/yr.	Total Annual Cost $/yr.
Unit 1	SCR	$193,045,300	$18,222,000	$11,330,000	$29,552,000
Unit 4	SCR	$259,358,600	$24,482,000	$15,491,000	$39,973,000

Table 5-3. NOx Control Cost Summary ($2020)
SJGS Units 1 & 4 – Assuming Equipment Life of 7-Years

Unit	NO_X Control Option	Total Capital Investment $	Annual Capital Cost $/yr.	Annual Operating Cost $/yr.	Total Annual Cost $/yr.
Unit 1	SCR	$193,045,300	$35,820,000	$11,330,000	$47,150,000
Unit 4	SCR	$259,358,600	$48,125,000	$15,491,000	$63,616,000

Table 5-4. NOx Control Cost Effectiveness ($2020)
SJGS Units 1 & 4

Unit	NO_X Control Option	Total Annual Cost ($/yr.)		Expected Emission Reduction	Average Annual Cost Effectiveness ($/ton_	
		20- Year Equipment Life	7-Year Equipment Life	tons NO_X/yr.	20-Year Equipment Life	7-Year Equipment Life
Unit 1	SCR	$29,552,000	$47,150,000	2,417	$12,227	$19,508
Unit 4	SCR	$39,973,000	$63,616,000	3,627	$11,021	$17,540

Based on costs and emission reductions summarized in Table 5-2 through Table 5-4 the average cost effectiveness of retrofit SCR on SJGS Units 1 & 4 is $12,227/ton and $11,021/ton, respectively assuming facility operations extend beyond 2048. Cost effectiveness is calculated based on a baseline 2018 NOx emission rates of 0.223 and 0.226 lb./MMBtu for Units 1 & 4, respectively, a controlled NOx emission rate of 0.05 lb./MMBtu with SCR, and assuming an 87% annual capacity factor. In the event facility operations cease prior to 2048, annualized capital costs increase, and the control systems become less cost-effective. Assuming an equipment life of 7-years, the average cost effectiveness of retrofit SCR on SJGS Units 1 & 4 increases to $19,508/ton and $17,540/ton, respectively.

5.2.2 Factor 2 – Time Necessary for Compliance

The time necessary for compliance is generally defined as the time needed for full implementation of the technically feasible control options. This includes the time needed to develop and implement the regulations, as well as the time needed to install the selected control equipment. The time needed to install the control equipment includes time for equipment procurement, design, fabrication, and installation.

Table 5-5 includes high-level estimated timeframes needed to engineer, design, procure, and install SCR on SJGS Units 1 & 4. The estimated timeframes do not account for time needed for New Mexico to develop and implement the second planning period Regional Haze SIP, nor do they include time needed for EPA to review and approve the SIP.

Table 5-5. NOx Emissions Control System Implementation Schedule for SJGS Units 1 & 4

NO_X Control Option	Total Months after SIP Approval
Conceptual Engineering	4
Permitting	12 – 16
Design Specification/Procurement	8 – 10
Detail Design/Fabrication	16 – 18
Construction / Startup	24 – 26
Total Time	Approx. 60 months

5.2.3 Factor 3: Energy Impacts and Non-Air Quality Environmental Impacts of Compliance

The primary purpose of the environmental impact analysis is to assess collateral environmental impacts due to control of the regulated pollutant in question. Environmental impacts may include solid or hazardous waste generation, wastewater discharges from a control device, increased emissions of other criteria or non-criteria pollutants, increased water consumption, and land use impacts.

Energy impacts associated with SCR control systems include the additional the power consumed to overcome pressure drop through the SCR catalyst, as well as energy consumed by the dilution air blowers, heaters, ammonia pumps, and other minor auxiliary loads. Sargent & Lundy included energy impacts as an annual operating cost in the SCR cost impact analysis.

Non-air quality environmental impacts associated with SCR include spent catalyst management, and anhydrous ammonia storage/handling. Anhydrous ammonia would introduce a hazardous material onto the site, and require development and implementation of a comprehensive risk management plan (RMP). SCR also has the potential to increase emissions of other air pollutants, including ammonia slip, sulfuric acid mist and $PM_{2.5}$. Anhydrous ammonia would likely be delivered to the facility by truck, increasing roadway fugitive dust emissions. A summary of the environmental and energy impacts associated with SCR is provided in Table 5-6.

Table 5-6. NOx Control Options: Summary of Energy and Non-Air Quality Environmental Impacts

Unit	Control Option	Collateral Environmental & Energy Impacts
Units 1 & 4	SCR	➢ Increased auxiliary power requirements and heat rate penalty ➢ Potential decrease in ammonia slip emission ➢ Potential increase in SO_3, sulfuric acid mist and PM2.5 emissions ➢ Increased fugitive dust emissions ➢ Spent catalyst management/handling

5.2.4 Factor 4: Remaining Useful Life

The evaluation of technically feasible control options should consider the source's remaining useful life (RUL) in determining the costs of compliance. The RUL is the difference between the date that controls would be put in place and the date that the facility permanently ceases operation. If the RUL of the unit is shorter than that of a particular control option, the RUL should be used to annualize costs. If the RUL exceeds the useful life of the control options, the RUL has no effect on the cost evaluation.

The cost of compliance for each control option (see, Section 5.2.1) calculates the annualized cost of capital by multiplying the total capital investment by a capital recovery factor (CRF). For this evaluation, the CRF was calculated two ways: (1) using an equipment life of 7-years based on the assumption that operations will cease at the facility in 2035; and (2) using an equipment life of 20-years based on the assumption that the facility will continuing operating past 2048. The 2035 date is based on the IRS section 45Q tax credit (45Q), which is available for 12 years of operation and then ceases. Based on current economic analysis, the facility may not be able to run economically beyond the 12 years and hence would shut down in 2035, assuming carbon capture system operation commence in 2023. The 20-year equipment life assumes the plant will continue operation beyond an assumed SCR equipment life of 20-years. Running the facility for 20 years, instead of 12, is premised on an unknowable change in Federal law in the length of the 45Q.

6. SO_2 FOUR-FACTOR ANALYSIS

This section of the SJGS Four-Factor Analysis includes an evaluation of control technologies available to SJGS with the potential to achieve further SO_2 emission reductions. Sargent & Lundy used a top-down approach to identify all available retrofit emission control technologies, eliminate technically infeasible options or options with no practical application to SJGS Units 1 & 4, and rank technically feasible control technologies by effectiveness.[25] Technically feasible SO_2 control options were evaluated for the four statutory factors listed in 40 CFR 51.308(f)(2).

6.1 SO_2 EMISSIONS CONTROLS

6.1.1 Coal Sulfur Content

The generation of SO_2 is directly related to the sulfur content and higher heating value (HHV) of the fuel burned. SJGS Units 1 & 4 currently fire western bituminous coal supplied by the adjacent mine, San Juan Coal Company, owned by Westmoreland Holdings. The current coal supply contract expires on June 30, 2022; however, San Juan Coal Company has offered SJGS a new coal contract for the years 2022 through 2035.

Baseline and projected HHV and coal sulfur content are listed in Table 6-1. Baseline coal quality data are based on actual average fuel analyses provided by SJGS for the year 2019. Projected coal quality values are based on information provided by the San Juan Mine for the years 2020 through 2034, and represent the highest equivalent SO2 emission rate expected during that time period on an annual average basis. Significant changes in coal quality are not anticipated through 2035, the term of the new coal contract.

Table 6-1. Baseline and Future Projected SJGS Coal Quality (Annual)

Parameter	Baseline	Projected Future (range)
HHV (Btu/lb.)	9,553	9,780 – 10,230
Sulfur (%)	1.08	0.70 – 1.36
Ash Content (%)	23.84	Not reported
Equivalent SO_2 in fuel (lb./MMBtu)	2.26	1.36 – 2.66

Based on existing and projected coal characteristics and control system performance, an average uncontrolled SO_2

[25] The top-down approach to evaluating potentially feasible control technologies is described in 40 CFR Part 51 Appendix Y, Section IV.D.

rate of 2.6 lb./MMBtu, based on the future projected average sulfur content and heating values, was used as the basis for evaluating the technical feasibility and effectiveness of SO_2 control technologies in this Four-Factor Analysis. Projected future actual emissions were calculated based on existing performance and anticipated future coal characteristics.

6.1.2 Identify Available SO_2 Control Options

SJGS Units 1 & 4 are currently equipped with WFGD control technology. The WFGD control systems on both units were upgraded in 2007-2008, including installation of dibasic acid injection system for enhanced SO_2 removal. Additional upgrades to the systems were made in 2016-2018 to adjust tray surface areas, increase spray nozzle orifice sizing, and adjust spray nozzle angles to optimize slurry/flue gas contact and enhance SO_2 removal.

In general, WFGD control systems remove SO_2 from the flue gas in an absorber vessel by passing the flue gas stream counter-current through a slurry of fine-ground limestone ($CaCO_3$). Scrubber slurry is sprayed into the vessel to promote intimate gas contact with fine droplets or thin films. The SO_2 gas is absorbed into the liquid and collected in an integrated reaction tank. Large quantities of air are injected into the reaction tank, where it is agitated and recirculated back to the absorption zone. Residence time of calcium-based solids in the tank is long enough to permit reaction of the sulfur-bearing ions stripped from the flue gas with the calcium ions and the oxygen in the air to produce gypsum solids ($CaSO_4$). The efficiency of a WFGD system is a function of several design and operating variables, including the Ca:S stoichiometric ratio in the absorber vessel, optimizing distribution of the slurry and gas flow to promote liquid/gas contact, the liquid-to-gas (L/G) ratio (a measurement of the amount of liquid slurry recycle to volumetric flow rate of gas passing through the absorber), and maintaining absorber vessel chemistry.

Since implementing control systems upgrades, SJGS Units 1 & 4 have achieved average annual SO_2 emission rates in the range of 0.04 to approximately 0.06 lb./MMBtu, which are generally equivalent to guarantee rates provided for new retrofit WFGD control systems. Based on uncontrolled SO_2 emission rates between approximately 1.6 and 2.6 lb./MMBtu, the existing WFGD control systems consistently achieve removal efficiencies greater than 95%.

Section II.B.3.f of the EPA Guidance Document ("*Sources that already have effective emission control technology in place*") provides specific guidance to States with respect to emission sources that already have effective emission control technology in place as a result of a previous regional haze SIP or to meet another CAA requirement. The EPA Guidance Document states that:

> In general, if post-combustion controls were selected and installed fairly recently (see illustrative examples below) to meet a CAA requirement, there will be only a low likelihood of a significant

> technological advancement that could provide further reasonable emission reductions having been made in the intervening period. If a source owner has recently made a significant expenditure that has resulted in significant reductions of visibility impairing pollutants at an emissions unit, it may be reasonable for the state to assume that additional controls for that unit are unlikely to be reasonable for the upcoming implementation period. A state that does not select a source or sources for the following or any similar reasons should explain why the decision is consistent with the requirement to make reasonable progress, i.e., why it is reasonable to assume for the purposes of efficiency and prioritization that a full four factor analysis would likely result in the conclusion that no further controls are necessary. (EPA Guidance Document, pg. 22)

Examples provided in the EPA Guidance Document include the following with respect to FGD control systems:

- For the purpose of SO_2 control measures, an EGU that has add-on flue gas desulfurization (FGD) and that meets the applicable alternative SO_2 emission limit of the 2012 Mercury Air Toxics Standards (MATS) rule for power plants. The two limits in the rule (0.2 lb./MMBtu for coal-fired EGUs or 0.3 lb./MMBtu for EGUs fired with oil-derived solid fuel) are low enough that it is unlikely that an analysis of control measures for a source already equipped with a scrubber and meeting one of these limits would conclude that even more stringent control of SO_2 is necessary to make reasonable progress.

- For the purposes of SO_2 and NOx control measures, a combustion source (e.g., an EGU or industrial boiler or process heater) that, during the first implementation period, installed an FGD system that operates year-round with an effectiveness of at least 90 percent…[26]

Because SJGS Units 1 & 4 are currently equipped with recently upgraded WFGD control systems, and because the control systems currently achieve SO_2 removal efficiencies of more than 95% and meet the applicable MATS emission limits, a full four-factor analysis of retrofit control technologies, including replacement FGD control options, would likely conclude that replacing the existing WFGD control systems would result in no significant additional SO_2 emission reductions, and therefore, would not be a practical or cost-effective option at SJGS.[27] For these reasons, the Four-Factor Analysis does not evaluate replacing the existing WFGDs with new wet or dry FGD control systems. Rather, the Four-Factor Analysis focuses on potential upgrades/modifications to the existing WFGD

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[26] See, EPA Guidance Document, pgs. 23-24. The Guidance Document notes that while a 90% control effectiveness is used in the example, the Agency would expect that any FGD system installed to meet CAA requirements since 2007 would have an effectiveness of 95% or higher.

[27] Section II.B.4.a of the 2019 EPA Guidance Document states that the "first step in characterizing control measures for a source is the identification of technically feasible control measures" for the pollutant under consideration, noting that "[a] state must reasonably pick and justify the measures that it will consider, recognizing that there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures."

control system that may provide an incremental reduction in SO_2 emissions.[28] WFGD operational practices and equipment upgrades included in the evaluation are listed in Table 6-2.

Table 6-2. Potentially Available SO2 Control System Upgrades
SJGS Units 1 & 4

SJGS Units 1 & 4
Existing WFGD Operational Improvements
Limestone Quality
Increased Limestone Addition
Existing WFGD Design Changes and Equipment Upgrades
Increase L/G Ratio
Additional Recycle Spray Level or Tray
Optimized Spray Nozzles and Flue Gas Flow Distribution
Chemical Additives

6.1.3 Technical Feasibility of FGD Equipment Upgrades/Operational Changes

Equipment upgrades and operational changes that may be available to provide an incremental increase SO_2 removal efficiencies at SJGS are described below. In general, upgrades are intended to increase the Ca:S stoichiometric ratio in the absorber vessel, increase L/G, and optimize slurry/flue gas contact.

Limestone Quality

Reagent quality directly affects the Ca:S stoichiometric ratio (i.e., limestone ($CaCO_3$) to inlet SO_2 ratio) in WFGD control systems. Using a high-quality limestone increases the availability of calcium to support process chemistry and reduces the limestone slurry injection rate needed for SO_2 removal. Limestone with a $CaCO_3$ content of 90% or greater is generally classified as high-quality limestone. Limestone with a higher $CaCO_3$ content may provide an incremental increase in SO_2 removal at constant slurry injection rates or provide the same reduction at lower slurry injection rates. SJGS currently uses high-quality limestone, as evidenced by the fact that both units currently achieve removal efficiencies of greater than 95%; thus, it is unlikely that a change in limestone quality would result in additional SO_2 removal than that currently achieved at the facility. Although utilizing a higher-quality limestone may

[28] The Four-Factor Analysis does not take into account potential SO_2 emission reductions associated with the carbon capture facility.

be a technically feasible operational change, it would not provide additional SO_2 removal, and is therefore, not considered an operational change with a practical application at SJGS.

Increased Limestone Addition

WFGD systems operate with a large volume of limestone slurry recirculated from the bottom of the vessel to the recycle-level spray headers. This slurry includes additional water from the mist eliminator wash water and condensed flue gas moisture. Reaction by-products (i.e., calcium sulfate and sulfite) also build up in the reaction vessel. As sulfur continues to react with the limestone, fresh limestone must be added to the vessel to maintain the necessary concentration and pH for the reaction. More frequent fresh limestone addition will ensure that there is a higher concentration of fresh limestone in the recycle slurry, rather than byproducts, which can improve the reaction efficiency of the WFGD control system.

The WFGD control systems at SJGS currently achieve removal efficiencies of 95% or greater. As such, it is unlikely that adding additional fresh limestone to the recirculation system would increase the Ca:S stoichiometric ratio in the reaction vessel or optimize absorber vessel chemistry. Furthermore, modifications to the recirculation system, slurry distribution, and blowdown and dewatering system would likely be required to accommodate additional limestone usage without causing issues with slurry pH levels and decreasing limestone utilization within the WFGD systems. Although additional limestone may be a technically feasible operational change, it would not provide additional SO_2 removal, and is therefore, not considered an operational change with a practical application at SJGS.

Increase L/G Ratio

Liquid to gas ratio (L/G) is a measurement of the amount of liquid slurry recycle to the volumetric flow rate of gas passing through the absorber vessel. Increased L/G results in additional contact time between the flue gas and limestone slurry in the absorber vessel which can increase removal efficiency. Increasing the capacity of the slurry feed pumps may be an option for increasing the liquid flowrate through the absorber vessel; however, increasing the absorber feed pump capacity and liquid flowrate through the recycle spray headers can exceed the design capabilities of the existing tray resulting in higher pressure drop in the absorber section. As such, replacing the absorber feed pump would likely require replacement or redesign of the existing tray. Existing spray headers and nozzles would also need to be assessed and qualified for operation with a higher flow rate.

Increasing slurry flow through the quencher section may be an option to increase L/G. This option requires replacing the existing quencher pumps with higher capacity pumps, assuming the recently redesigned spray headers and nozzles would be capable of withstanding increased flow without modifications. Detailed engineering evaluation of the existing spray nozzles, spray headers, and interconnecting piping would be needed to determine if replacement and/or modification of the existing equipment would be needed to support a higher flow rate.

Although increasing L/G is often evaluated as an option to achieve additional SO_2 removal on an existing WFGD control system, detailed engineering assessments are needed to evaluate technical feasibility and to identify equipment replacement/modification requirements to support increased liquid flows. Furthermore, because the existing WFGD control systems at SJGS provide very effective SO_2 control, it is unlikely that increasing the liquid flow rate through the absorber or quencher section of the WFGDs would provide additional SO_2 control. For these reasons, increasing L/G is not considered an equipment upgrade or operational change with a practical application at SJGS.

Additional Recycle Spray Level or Tray

Another option that may be available to increase L/G involves adding an additional spray level or tray in the absorber section of the WFGD. However, this approach requires sufficient room in the absorber section of the WFGD, or reconfiguring the absorber section to provide additional space, move the mist eliminator section into the outlet cone, and/or relocate or redesign the liquid-gas separator bowl beneath the existing tray. Adding an additional spray level or tray in the absorber section of the WFGD can require significant modifications to the absorber vessel. Furthermore, as with other potentially available options to increase L/G, it is unlikely that an additional spray level or tray would provide SO_2 control beyond that achieved with the existing design. For these reasons, increasing L/G by adding spray levels or an additional tray is not considered an equipment upgrade or operational change with a practical application at SJGS.

Optimized Spray Nozzle and Flue Gas Distribution

Optimizing the distribution of the slurry and gas flow, as well as improvements to spray nozzle design, can reduce localized flue gas slippage and increase the overall removal efficiency of a WFGD control system. Improvements to spray design can provide a better pattern of coverage of the slurry spray through the cross-sectional area of the absorber, finer droplet size, and more even coverage. However, a detailed engineering evaluation is needed to determine the technical feasibility of spray nozzle replacement. For example, nozzle replacement may not be feasible due to the proximity of the nozzles to the absorber section tray and mist eliminator. Nevertheless, it is evident from the SO_2 removal efficiencies currently achieved in practice at SJGS, that the WFGD control systems at SJGS achieve effective slurry distribution and slurry/flue gas contact; thus, replacing the existing spray nozzles is not considered an equipment upgrade or operational change with a practical application at SJGS.

Chemical Additives

The pH within a WFGD system must be properly balanced to allow for proper reaction kinetics and to limit the scaling potential within the system. As SO_2 from the flue gas dissolves in the slurry, the water becomes acidic and limestone is added, neutralizing the slurry. However, limestone does not readily dissolve, which can make it difficult to neutralize the SO_2 as it enters. In efforts to mitigate this issue, chemical additives have been developed for use in WFGD systems to improve the ability for limestone to neutralize and react with the SO_2 absorbed into the slurry. Use of additives, such as adipic or dibasic acid (DBA) can balance the pH in the system and increase the removal efficiency in WFGD systems. The SJGS WFGD control systems were retrofit with DBA injection system to control pH of the WFGD absorber vessel; thus, chemical additives are not considered an operational change with a practical application at SJGS.

6.1.4 Evaluate Technically Feasible SO_2 Control Options for Control Effectiveness

As described in Section 6.1.2, the SJGS WFGD control systems currently achieve very effective SO_2 control. Operational changes and equipment upgrades have been integrated into the WFGD control systems at SJGS to achieve adequate slurry injection rates, Ca:S stoichiometric ratios, L/G, and slurry/flue gas distribution and mixing. In addition, a DBA additive system is available to control absorber vessel pH and reaction chemistry. The control systems achieve SO_2 removal efficiencies of 95% or greater, and consistently achieve controlled SO_2 emission rates of 0.06 lb./MMBtu or less. It is unlikely that operational changes and equipment upgrades that have been implemented on other existing WFGD control systems (evaluated in Section 6.1.2) would provide additional SO_2 removal beyond that currently achieved at SJGS; thus, operational changes and equipment upgrades are not considered technically feasible SO_2 control options with a practical application at SJGS.

6.2 EVALUATE STATUTORY FACTORS - SO_2 CONTROL

Based on an evaluation of potentially available operational changes and equipment upgrades (Section 6.1.2), there are no technically feasible equipment upgrades or operational changes that would provide additional control beyond that currently achieved at SJGS. As such, operational changes and equipment upgrades are not considered technically feasible SO_2 control options with a practical application at SJGS, and no evaluation of the statutory factors (i.e., Cost of Compliance; Time Necessary for Compliance; Energy Impacts and Non-Air Quality Environmental Impacts of Compliance; and Remaining Useful Life) is required.

The existing WFGD control systems on SJGS Units 1 & 4 provide very effective SO_2 control. Potentially available operational changes or equipment upgrades would likely not provide additional SO_2 control beyond that currently achieved at SJGS, and reconfiguring or replacing the absorber vessels or replacing would not be a practical SO_2 control option SJGS.

As noted in Section II.B.3.f of the 2019 EPA Guidance Document "[i]f a source owner has recently made a significant expenditure that has resulted in significant reductions of visibility impairing pollutants at an emissions unit, it may be reasonable for the state to assume that additional controls for that unit are unlikely to be reasonable for the upcoming implementation period." (EPA Guidance Document, pg. 22) Examples provided in the EPA Guidance Document include FGD control systems that meet the applicable alternative MATS SO_2 emission limit of 0.2 lb./MMBtu for coal-fired EGUs and FGD systems that operates year-round with an effectiveness of at least 90%. The WFGD control systems at SJGS currently achieve SO_2 removal efficiencies of 95% or more and SO_2 emission rates well below the applicable MATS limit.

7. FOUR-FACTOR ANALYSIS - SUMMARY

The Regional Haze Rule requires States to update their Regional Haze SIPs every 10-years to ensure reasonable progress towards meeting the goal of achieving natural visibility conditions at Class I areas by 2064. SIPs for the second planning period, which ends in 2028, must be submitted to EPA for review and approval by July 31, 2021. Among other things, second planning period SIPs must include an evaluation of emission reductions from existing sources that may impact visibility in one or more Class I area. Emission reductions from existing sources are to be determined based on a reasonable progress "four-factor analysis" of available emission control technologies.

Sargent & Lundy was retained by Enchant/Farmington to prepare a Four-Factor Analysis for the control of SO_2 and NO_X emissions from SJGS. SJGS is a coal-fired, steam electric generating facility located in northwest New Mexico, approximately 15 miles northwest of the City of Farmington. SJGS currently has two operating coal-fired steam electric generating units, Units 1 & 4, and two recently retired units, Units 2 & 3. The SJGS Four-Factor Analysis includes an assessment of potentially available emission reduction measures, taking into consideration the four statutory factors listed in 40 CFR 51.308(f)(2). Technically feasible SO_2 and NO_X emission reduction measures are evaluated for the following four statutory factors:

- Factor 1: The cost of compliance
- Factor 2: The time necessary to achieve compliances
- Factor 3: The energy and non-air quality environmental impact of compliance
- Factor 4: The remaining useful life of any existing source subject to such requirements

Summary of the SJGS Units 1 & 4 NOx Four-Factor Analysis

Based on a review of physical, chemical, and engineering principles, and an assessment of NOx control technologies installed on existing coal-fired boilers, as well as operational practices and equipment upgrades already implemented on SJGS Units 1 & 4, the only potentially available option to further NOx control on SJGS Units 1 & 4 is replacing the existing SNCR control systems with selective catalytic reduction (SCR). Other potentially available NOx control technologies would not achieve additional NOx reduction beyond that achieved with the exiting SNCR systems. Innovative NOx control technologies, and multi-pollutant control technologies, have not developed beyond the demonstration stage, have not been demonstrated on large coal-fired boilers, or are not commercially available. Similarly, the hybrid SNCR/in-duct SCR control system would pose significant engineering and design challenges to determine technical feasibility and effectiveness on SJGS Units 1 & 4, and is therefore, not an available NOx control technology.

Table 7-1 provides a comparison of emission rates achieved with SNCR and emission rates achievable with retrofit SCR, the only technically feasible and commercially available NOx control technology at SJGS, and the corresponding reduction in annual emissions. Table 7-2 and Table 7-3 present the total capital investment, annualized capital cost, annual operating and maintenance (O&M) costs, and total annual costs associated with installing and operating SCR on SJGS Units 1 & 4. As discussed in Section 5.2.4 of this evaluation, capital costs were annualized using two different equipment lives: (1) an equipment life of 7-years based on the assumption that facility operations cease in 2035; and (2) and equipment life of 20-years based on the assumption that operations extend beyond 2048. Table 7-4 show the average annual cost effectiveness for the control system for both scenarios. Additional cost details are provided in Appendix B.

Table 7-1. Technically Feasible NOx Control Options for SJGS Units 1 & 4

	Unit 1		Unit 4	
Baseline 2028 Annual Heat Input (MMBtu/yr)	27,946,940		41,223,071	
Control Technology	**lb./MMBtu**	**tpy**	**lb./MMBtu**	**tpy**
Baseline (LNB/OFA/SNCR)	0.233	3,116	0.226	4,658
SCR	0.05	699	0.05	1,031
Annual Emission Reductions	--	2,417	--	3,627

Note 1. Emission rates shown above represent average emissions that each control option would be expected to achieve on an ongoing long-term basis under normal operating conditions. Emission rates are provided for comparative purposes only and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control-system-specific basis, and additional compliance margin would likely be needed to account for all operating conditions.

Table 7-2. NOx Control Cost Summary ($2020)
SJGS Units 1 & 4 – Assuming Equipment Life of 20-Years

Unit	NOx Control Option	Total Capital Investment $	Annual Capital Cost $/yr.	Annual Operating Cost $/yr.	Total Annual Cost $/yr.
Unit 1	SCR	$193,045,300	$18,222,000	$11,330,000	$29,552,000
Unit 4	SCR	$259,358,600	$24,482,000	$15,491,000	$39,973,000

Table 7-3. NOx Control Cost Summary ($2020)
SJGS Units 1 & 4 – Assuming Equipment Life of 7-Years

Unit	NO_X Control Option	Total Capital Investment $	Annual Capital Cost $/yr.	Annual Operating Cost $/yr.	Total Annual Cost $/yr.
Unit 1	SCR	$193,045,300	$35,820,000	$11,330,000	$47,150,000
Unit 4	SCR	$259,358,600	$48,125,000	$15,491,000	$63,616,000

Table 7-4. NOx Control Cost Effectiveness ($2020)
SJGS Units 1 & 4

Unit	NO_X Control Option	Total Annual Cost ($/yr.)		Expected Emission Reduction	Average Annual Cost Effectiveness ($/ton)	
		20- Year Equipment Life	7-Year Equipment Life	NOx tpy	20-Year Equipment Life	7-Year Equipment Life
Unit 1	SCR	$29,552,000	$47,150,000	2,417	$12,227	$19,508
Unit 4	SCR	$39,973,000	$63,616,000	3,627	$11,021	$17,540

Based on costs and emission reductions summarized in Table 7-2 through Table 7-4, the average cost effectiveness of retrofit SCR on SJGS Units 1 & 4 is $12,227/ton and $11,021/ton, respectively, assuming facility operations extend beyond 2048. Average cost-effectiveness is calculated based on baseline 2028 NOx emission rates of 0.223 and 0.226 lb./MMBtu for Units 1 & 4, respectively, a controlled NOx emission rate of 0.05 lb./MMBtu with SCR, and assuming a 2028 annual capacity factor of approximately 87% for each unit. In the event facility operations cease prior to 2048, annualized capital costs increase, and the control systems become less cost-effective. Assuming an equipment life of 7-years, the average cost effectiveness of retrofit SCR on SJGS Units 1 & 4 increases to $19,508/ton and $17,540/ton, respectively.

Summary of the SJGS Units 1 & 4 SO_2 Four-Factor Analysis

SJGS Units 1 & 4 are currently equipped with wet flue gas desulfurization (WFGD) SO_2 control systems. The SJGS WFGD control systems currently achieve very effective SO_2 control. Operational changes and equipment upgrades have been integrated into the WFGD control systems at SJGS to achieve adequate slurry injection rates, calcium-to-sulfur (Ca:S) stoichiometric ratios, liquid-to gas ratios (L/G), and slurry/flue gas distribution and mixing. In addition, a dibasic acid (DBA) additive system is available to control absorber vessel pH and reaction chemistry. The control systems currently achieve SO_2 removal efficiencies of 95% or greater, and consistently achieve controlled SO_2 emission rates of 0.06 lb./MMBtu or less. Based on a review of potentially available control options, it is unlikely that operational changes and equipment upgrades would provide additional SO_2 removal beyond that currently achieved at SJGS.

As noted in Section II.B.3.f of EPA's 2019 Second Planning Period Guidance Document (*Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*), "[i]f a source owner has recently made a significant expenditure that has resulted in significant reductions of visibility impairing pollutants at an emissions unit, it may be reasonable for the state to assume that additional controls for that unit are unlikely to be reasonable for the upcoming implementation period." Examples provided in the EPA Guidance Document include FGD control systems that meet the applicable Mercury and Air Toxic Standard (MATS) SO_2 emission limit of 0.2 lb./MMBtu for coal-fired EGUs, and FGD systems that operate year-round with an effectiveness of at least 90%. The WFGD control systems at SJGS currently achieve SO_2 removal efficiencies of 95% or more and SO_2 emission rates well below the applicable MATS limit. Thus, no additional upgrades or modifications to the existing WFGD control systems are warranted for the second planning period.

Projected 2028 SJGS Emissions

Based on the review of potentially available NOx and SO_2 control technologies, including technical feasibility, effectiveness, costs, cost-effectiveness, and the remaining statutory factors, projected emissions from SJGS Units 1 & 4 in 2028 are summarized in Table 7-5. Projected 2028 emission calculations are based on the following assumptions:

- The projected NOx emission rates (lb./MMBtu) were set equal to the 2017-2019 baseline rates based on the assumption that SJGS Units 1 & 4 will continue to control NOx emissions using a combination of combustion controls and SNCR. No credit was taken for potential NOx emission reductions associate with the carbon capture facility.
- The projected short-term (hourly) SO_2 emission rates (lb./MMBtu) were set equal to the 2017-2019 baseline rates based on the assumption that SJGS Unit 1 & 4 will continue to operate the existing WFGD control systems with no credit taken for SO_2 emission reductions associated with the carbon capture facility. Annual average SO_2 emissions were calculated assuming an additional 50% SO_2 reduction through the carbon capture system.

Annual emissions were calculated assuming an annual capacity factor of 87% to account for increased boiler utilization in 2028.

Table 7-5. Projected 2028 Baseline SO_2 / NOx Emissions for SJGS Units 1 & 4

Pollutant	Representative Baseline Periods	
	Unit 1 Note 1	Unit 4
Full Load Heat Input	3,667 MMBtu	5,409 MMBtu
Projected Annual Heat Input	27,946,940 MMBtu	41,223,071 MMBtu
Projected Annual Capacity Factor	87%	87%
SO_2 Controls	WFGD	WFGD
Projected 2028 SO_2 Emissions	0.037 lb./MMBtu (hourly) 0.019 lb./MMBtu (annual average)	0.056 lb./MMBtu (hourly) 0.028 lb./MMBtu (annual average)
	136 lb./hr. (hourly)	303 lb./hr. (hourly)
	265 tpy	557 tpy
NOx Controls	LNB/OFA/NN + SNCR	LNB/OFA/NN + SNCR
Projected 2028 NOx Emissions	0.223 lb./MMBtu	0.226 lb./MMBtu
	818 lb./hr.	1,222 lb./hr.
	3,116 tpy	4,658 tpy

APPENDIX A

SJGS UNITS 1 & 4 BASELINE EMISSIONS

SJGS Unit 1
Baseline Monthly Emissions and Heat Input (May 2016 – December 2019)

Month	Year	SO2 (tons)	NOx (tons)	Heat Input (MMBtu)
5	2016	60.8	271.4	2,383,738
6	2016	58.9	240.4	2,119,773
7	2016	34.1	241.7	2,164,545
8	2016	22.1	299.1	2,619,117
9	2016	25.6	196.3	1,792,839
10	2016	90.3	289.3	2,535,856
11	2016	46.9	208.7	1,902,177
12	2016	53.7	222.7	1,985,960
1	2017	35.7	226.2	2,076,689
2	2017	61.4	220.7	1,955,399
3	2017	38.2	259.0	2,292,490
4	2017	49.4	246.1	2,156,206
5	2017	54.4	138.4	1,255,511
6	2017	63.0	281.8	2,523,340
7	2017	35.4	294.3	2,609,989
8	2017	37.8	246.1	2,215,151
9	2017	43.1	276.7	2,477,405
10	2017	24.7	262.9	2,366,182
11	2017	39.7	160.8	1,455,860
12	2017	35.9	256.5	2,308,647
1	2018	13.0	212.0	1,910,656
2	2018	26.6	182.7	1,637,474
3	2018	30.4	116.4	1,053,219
4	2018			
5	2018			
6	2018			
7	2018	21.5	130.7	1,129,800
8	2018	39.8	277.6	2,512,311
9	2018	35.1	207.4	1,858,739
10	2018	36.9	208.1	1,869,783
11	2018	34.1	266.1	2,395,571
12	2018	36.8	279.7	2,528,114
1	2019	49.7	234.5	1,990,867
2	2019	61.1	232.5	2,089,590
3	2019	11.4	121.4	1,099,427
4	2019	30.1	252.0	2,266,461
5	2019	37.2	199.7	1,782,367
6	2019	37.6	200.7	1,788,789
7	2019	40.7	203.0	1,823,764
8	2019	33.5	253.5	2,276,157
9	2019	39.3	268.7	2,402,770
10	2019	34.3	229.5	2,047,676
11	2019	31.4	218.9	1,957,016
12	2019	22.5	200.7	1,801,479

SJGS Unit 4
Baseline Monthly Emissions and Heat Input (May 2016 – December 2019)

Month	Year	SO2 (tons)	NOx (tons)	Heat Input (MMBtu)
5	2016	128.0	373.7	3,262,204
6	2016	136.7	432.9	3,820,897
7	2016	90.2	365.1	3,281,487
8	2016	93.0	332.3	3,091,774
9	2016	78.8	316.0	3,116,730
10	2016	120.8	389.5	3,710,092
11	2016	83.4	379.6	3,489,145
12	2016	65.7	378.5	3,258,536
1	2017	112.0	333.1	2,970,139
2	2017	116.7	364.0	3,328,939
3	2017	113.2	419.4	3,708,011
4	2017	95.6	381.2	3,377,314
5	2017	96.9	294.3	2,613,855
6	2017	135.1	433.9	3,828,856
7	2017	139.6	382.2	3,456,282
8	2017	140.8	482.8	4,301,326
9	2017	91.1	414.5	3,727,615
10	2017	81.3	469.3	4,095,858
11	2017	107.5	421.1	3,737,170
12	2017	51.3	328.8	2,916,225
1	2018	52.7	380.3	3,357,635
2	2018	92.3	398.1	3,570,123
3	2018	97.4	445.1	3,931,867
4	2018	85.4	347.3	3,087,646
5	2018	100.3	407.4	3,620,364
6	2018	95.7	423.0	3,710,005
7	2018	81.9	385.3	3,402,094
8	2018	89.1	429.1	3,823,474
9	2018	64.8	287.1	2,525,784
10	2018	38.1	215.3	1,884,886
11	2018	65.8	358.5	3,144,396
12	2018	108.7	445.9	3,938,011
1	2019	85.7	333.2	2,899,777
2	2019	83.6	351.3	3,110,278
3	2019	42.5	310.6	2,782,780
4	2019			
5	2019	53.1	131.1	1,193,668
6	2019	152.1	446.6	3,944,364
7	2019	133.6	449.7	3,950,238
8	2019	90.7	388.1	3,434,903
9	2019	95.0	345.7	3,075,079
10	2019	132.3	420.3	3,683,179
11	2019	82.4	376.2	3,291,807
12	2019	73.4	310.3	2,719,716

SJGS Units 1 & 4
Baseline Annual Heat Input (2020)

Year / Heat Input	Units	Unit 1	Unit 4
2017 Total Annual Heat Input	MMBtu	25,692,872	42,061,590
2018 Total Annual Heat Input	MMBtu	16,895,666	39,996,285
2019 Total Annual Heat Input	MMBtu	23,326,363	34,085,789
Average Monthly Heat Input (when operating)	MMBtu/mo.	1,997,421	3,318,390
Average Monthly Heat Input x 12 (Baseline Current Annual Heat Input)	MMBtu/yr.	23,969,055	39,820,685

SJGS Units 1 & 4
Baseline SO_2 and NOx Emissions (lb./MMBtu / tpy)

Baseline Emissions	Unit 1 SO2	Unit 4 SO2	Unit 1 NOx	Unit 4 NOx
2017 Total Emissions (tons)	518.8	1,281	2,869	4,725
2018 Total Emissions (tons)	274.2	972	1,881	4,522
2019 Total Emissions (tons)	428.9	1,024	2,615	3,863
Average Tons/Months 2017-2019 during operation:	37	94	223	375
Average Tons/Month x 12 Months (Baseline Annual Emissions)	444	1,124	2,678	4,495
Average Baseline Emission Rate (lb/MMBtu)	0.037	0.056	0.223	0.226

SJGS Units 1 & 4
Projected Baseline Annual Heat Input and Emissions (2028)

Parameter	**Units**	**UNIT 1**	**UNIT 4**
Projected Annual Heat Input (2028)	MMBtu/yr.	**27,946,940**	**41,223,071**
Full Load Heat Input	MMBtu/hr.	3,667	5,409
Projected Annual Capacity Factor	%	87.0%	87.0%
Projected Emissions		**Unit 1**	**Unit 4**
NOx Short-Term Rate	lb./MMBtu	0.223	0.226
	lb./hr	818	1,222
NOx Annual Emissions	lb./MMBtu	0.223	0.226
	tpy	3,116	4,658
SO_2 Short-Term Rate (no DCC)	lb./MMBtu	0.037	0.056
	lb/hr	136	303
SO_2 Annual Emissions	lb./MMBtu	0.019	0.028
	tpy	265	577

APPENDIX B

NO_X CONTROL COST-EFFECTIVENESS ESTIMATES

SJGS Units 1 & 4
SCR Cost Estimate (Capital Costs, 20-yr. Equipment Life, $2020)

CAPITAL COSTS	Cost (2020$)		Basis
	Unit 1	Unit 4	
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$54,951,441	$73,323,789	Based on Sargent & Lundy's conceptual cost estimating system. Includes costs for equipment, and material. Common ammonia system split evenly between Units
Instrumentation	$0	$0	Included in equipment and materials cost
Freight	$2,747,572	$3,666,189	5% of Equipment/Material Cost
Total PEC	$57,699,013	$76,989,978	
Direct Installation Costs			
Labor	$50,129,659	$67,870,712	Based on Sargent & Lundy's conceptual cost estimating system. Includes construction equipment costs.
Scaffolding	$2,627,027	$3,529,863	2.5% of E&M and Labor total
Mobilization / Demobilization	$751,945	$1,018,061	1.5% of Labor
Consumables	$525,405	$705,973	0.5% of E&M and Labor total
Labor Cost Due To Overtime Inefficiency	$2,506,483	$3,393,536	5% of Labor
Total Direct Installation Costs	$56,540,519	$76,518,143	
Total Direct Costs (PEC + Direct Installation Costs)	**$114,239,532**	**$153,508,121**	
Indirect Costs			
EPC Engineering, Procurement & Project Services	$9,139,163	$12,280,650	8% of Total Direct & Construction Indirect Cost
EPC Construction Management	$3,427,186	$4,605,244	3% of Total Direct & Construction Indirect Cost
EPC S-U/Commissioning	$1,142,395	$1,535,081	1% of Total Direct & Construction Indirect Cost
EPC Fee	$19,192,241	$25,789,364	15% of Total Direct & Construction Indirect Cost, EPC Services, EPC Construction Management and EPC Startup and Commissioning
Owner's Engineer & Construction Management	$4,078,351	$5,480,240	3.5% of Total Direct & Construction Indirect Cost
Performance Testing/Unit	$100,000	$100,000	
Total Indirect Costs	**$37,079,337**	**$49,790,579**	
Contingency	**$30,264,000**	**$40,660,000**	20% of Direct and Indirect Costs
	$181,582,869	**$243,958,700**	
New Mexico Gross Receipt Tax	**$11,462,419**	**$15,399,893**	Included as 6.3125% sales tax
Total Capital Investment (TCI) 2020$	**$193,045,300**	**$259,358,600**	sum of direct capital costs, indirect capital. costs, and contingency. Escalated to 2020$
Capital Recovery Factor (CRF) $= i(1+i)^n / (1+i)^n - 1$	0.0944	0.0944	20-year life of equipment (years) @ 7% interest.
Annualized Capital Costs (CRF x TCI)	**$18,222,000**	**$24,482,000**	

SJGS Units 1 & 4
SCR Cost Estimate (Annual O&M and Total Annual Cost, 20-year Equipment Life, $2020)

OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost (net change)	-$529,000	-$852,000	Based on dry urea reagent cost of $420.72 per ton.
Ammonia Reagent Cost (net change)	$1,064,000	$1,570,000	Based on ammonia reagent cost of $785 per ton.
RO Water Cost (net change)	-$10,000	-$17,000	Based on water cost of $6 per 1,000 gallons.
Steam Cost (net change)	$74,000	$111,000	Based on steam cost of $5 per MMBtu.
Catalyst Replacement and Disposal Cost (net change)	$1,164,000	$1,807,000	Based on catalyst cost of $4500 per m3 and catalyst disposal cost of $1000 per m3; includes installation and removal labor.
Auxiliary Power Cost (net change)	-$473,000	-$411,000	Based on auxiliary power cost of $37 per MWh.
Total Variable O&M Costs	$1,290,000	$2,208,000	
Fixed O&M Costs			
Additional Operators per Shift	1	1	
Operating Labor	$526,000	$526,000	Assume $60/hr for each additional operator.
Supervisor Labor	$79,000	$79,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$1,714,000	$2,303,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$2,319,000	$2,908,000	
Indirect Operating Cost			
Property Taxes	$1,930,000	$2,594,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$1,930,000	$2,594,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$3,861,000	$5,187,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$7,721,000	$10,375,000	
Total Annual Operating Cost (net change)	**$11,330,000**	**$15,491,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$18,222,000	$24,482,000	
Annual Operating Cost	$11,330,000	$15,491,000	
Total Annual Cost	**$29,552,000**	**$39,973,000**	

SJGS Units 1 & 4
SCR Cost Estimate (Cost Effectiveness, 20-year Equipment Life, $2020)

NOx Control Cost Effectiveness	Unit 1	Unit 4
Baseline Annual Heat Input (2028)	27,946,940	41,223,071
Baseline Capacity Factor (2028)	87.0%	87.0%
Baseline NO_X Emissions, lb/MMBtu	0.223	0.226
Baseline Annual Emissions (tpy)	3,116	4,658
Projected Annual Heat Input (MMBtu)	27,946,940	41,223,071
Projected Annual Capacity Factor	87%	87%
Post SCR NO_X Emissions, lb/MMBtu	0.05	0.05
Post SCR Annual NOx Emissions (tpy)	699	1,031
Annual Emission Reductions	2,417	3,627
Total Annual Costs ($/yr)	29,552,000	39,973,000
Average Cost Effectiveness ($/ton)	$12,227	$11,021

SJGS Units 1 & 4
SCR Cost Estimate (Capital Costs, 7-yr. Equipment Life, $2020)

CAPITAL COSTS	Cost (2020$)		Basis
	Unit 1	Unit 4	
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$54,951,441	$73,323,789	Based on Sargent & Lundy's conceptual cost estimating system. Includes costs for equipment, and material. Common ammonia system split evenly between Units
Instrumentation	$0	$0	Included in equipment and materials cost
Freight	$2,747,572	$3,666,189	5% of Equipment/Material Cost
Total PEC	$57,699,013	$76,989,978	
Direct Installation Costs			
Labor	$50,129,659	$67,870,712	Based on Sargent & Lundy's conceptual cost estimating system. Includes construction equipment costs.
Scaffolding	$2,627,027	$3,529,863	2.5% of E&M and Labor total
Mobilization / Demobilization	$751,945	$1,018,061	1.5% of Labor
Consumables	$525,405	$705,973	0.5% of E&M and Labor total
Labor Cost Due To Overtime Inefficiency	$2,506,483	$3,393,536	5% of Labor
Total Direct Installation Costs	$56,540,519	$76,518,143	
Total Direct Costs (PEC + Direct Installation Costs)	**$114,239,532**	**$153,508,121**	
Indirect Costs			
EPC Engineering, Procurement & Project Services	$9,139,163	$12,280,650	8% of Total Direct & Construction Indirect Cost
EPC Construction Management	$3,427,186	$4,605,244	3% of Total Direct & Construction Indirect Cost
EPC S-U/Commissioning	$1,142,395	$1,535,081	1% of Total Direct & Construction Indirect Cost
EPC Fee	$19,192,241	$25,789,364	15% of Total Direct & Construction Indirect Cost, EPC Services, EPC Construction Management and EPC Startup Commissioning
Owner's Engineer & Construction Management	$4,078,351	$5,480,240	3.5% of Total Direct & Construction Indirect Cost
Performance Testing/Unit	$100,000	$100,000	
Total Indirect Costs	**$37,079,337**	**$49,790,579**	
Contingency	**$30,264,000**	**$40,660,000**	20% of Direct and Indirect Costs
New Mexico Gross Receipt Tax	**$11,462,419**	**$15,399,893**	Included as 6.3125% sales tax
Total Capital Investment (TCI) 2020$	**$193,045,300**	**$259,358,600**	sum of direct capital costs, indirect capital. costs, and contingency. Escalated to 2020$
Capital Recovery Factor (CRF) = $i(1+ i)^n$ / $(1 + i)^n - 1$	0.1856	0.1856	7-year life of equipment (years) @ 7% interest.
Annualized Capital Costs (CRF x TCI)	**$35,820,000**	**$48,125,000**	

SJGS Units 1 & 4

Sargent & Lundy

SJGS Units 1 & 4
SCR Cost Estimate (Annual O&M and Total Annual Cost, 7-year Equipment Life, $2020)

OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost (net change)	-$529,000	-$852,000	Based on dry urea reagent cost of $420.72 per ton.
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Auxiliary Power Cost (net change)	-$473,000	-$411,000	Based on auxiliary power cost of $37 per MWh.
Total Variable O&M Costs	$1,290,000	$2,208,000	
Fixed O&M Costs			
Additional Operators per Shift	1	1	
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Total Fixed O&M Cost	$2,319,000	$2,908,000	
Indirect Operating Cost			
Property Taxes	$1,930,000	$2,594,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$1,930,000	$2,594,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$3,861,000	$5,187,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$7,721,000	$10,375,000	
Total Annual Operating Cost (net change)	**$11,330,000**	**$15,491,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$35,820,000	$48,125,000	
Annual Operating Cost	$11,330,000	$15,491,000	
Total Annual Cost	**$47,150,000**	**$63,616,000**	

SJGS Units 1 & 4
SCR Cost Estimate (Cost Effectiveness, 7-year Equipment Life, $2020)

NOx Control Cost Effectiveness	Unit 1	Unit 4
Baseline Annual Heat Input (2028)	27,946,940	41,223,071
Baseline Capacity Factor (2028)	87.0%	87.0%
Baseline NO_X Emissions, lb/MMBtu	0.223	0.226
Baseline Annual Emissions (tpy)	3,116	4,658
Projected Annual Heat Input (MMBtu)	27,946,940	41,223,071
Projected Annual Capacity Factor	87%	87%
Post SCR NO_X Emissions, lb/MMBtu	0.05	0.05
Post SCR Annual NOx Emissions (tpy)	699	1,031
Annual Emission Reductions	2,417	3,627
Total Annual Costs ($/yr)	$ 47,150,000	$ 63,616,000
Average Cost Effectiveness ($/ton)	$19,508	$17,540