El Paso Natural Gas Company, L.L.C.
a Kinder Morgan company

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DEC 02 2022
Air Quality Bureau

November 30, 2022

FEDEX 3914 4685 2597

Program Manager
Compliance Reporting Section
NMED – Air Quality Bureau
525 Camino Del Los Marquez, Suite 1
Santa Fe, New Mexico 87505

Re: Alternative Emissions Standards Proposal for EPNG's Ten (10) GE Gas Turbines

Dear Madam or Sir:

In accordance with 20.2.50.113.B(11) of New Mexico Administrative Code (NMAC), El Paso Natural Gas Company, L.L.C. (EPNG) requests Alternative Emission Standards (AES) for NOx for ten (10) stationary GE gas turbines on the basis of economic infeasibility. EPNG conducted a technical and economic analysis of emissions controls to reduce NOx emissions for 10 gas turbines and concluded that AES for NOx for these turbines are warranted because the cost of compliance for technically feasible retrofit emissions control technologies is not economically feasible. The AES Proposal as well as an independent third party certification of an evaluation of the proposed AES are attached.

If you have any questions on this submittal, please contact me at (303) 914-7616 or Weiwen_daly@kindermorgan.com.

Sincerely,

Weiwen Daly
Sr. EHS Engineer
El Paso Natural Gas Company, L. L. C.
Air Permitting & Compliance – East
KMI-Natural Gas Pipelines

Enclosures: Alternative Emission Standards Proposal for NOx
Certification of an Evaluation of the proposed AES by ALL4 LLC

BARR

New Mexico Alternative Emission Standards Proposal

Prepared for
El Paso Natural Gas Company, LLC

November 2022

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New Mexico Alternative Emission Standards Proposal

November 2022

Contents

List of Tables

List of Appendices

1 Executive Summary

The New Mexico Environmental Department (NMED) finalized the Ozone Precursor rule under 20.2.50 NMAC to reduce ozone emissions at sources causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard for ozone. In lieu of meeting the emission standards established under 20.2.50.113 for portable and stationary natural gas-fired combustion turbines, owners and operators may submit a request for alternative emission standards for a specific engine or turbine based on technical impracticability or economic infeasibility. El Paso Natural Gas Company, L.L.C. (EPNG) requests alternative emission standards for ten stationary natural gas-fired combustion turbines on the basis of economic infeasibility.

EPNG conducted a technical and economic analysis of emission controls for ten of the company's stationary natural gas-fired combustion turbines to reduce NO_X emissions. The only technically practicable technology for each turbine is Selective Catalytic Reduction (SCR). The cost-effectiveness of SCR installation is summarized below in Table 1-1. EPNG has concluded that alternative emission standards for NOx for specific units subject to 20.2.50.113 are warranted because the cost of compliance for technically feasible retrofit emission control technologies is not economically reasonable.

Table 1-1 Summary of SCR Cost Effectiveness Evaluation

Turbine Location	Unit No.	Permitted Turbine Rating (hp)	Cost Effectiveness ($/ton NO_X Removed)
Afton	A-01	6,150	$11,697
Afton	A-02	6,150	$11,097
Afton	A-03	6,150	$11,097
Belen	A-01	4,737	$30,794
Belen	A-02	4,737	$29,214
Caprock	A-01	6,026	$9,933
Caprock	A-02	4,879	$29,283
Pecos River	A-01	7,150	$8,261
Pecos River	A-02	7,150	$11,097
Pecos River	A-03	7,150	$11,097

2 Introduction

The regulatory background and turbine information are summarized below.

2.1 Regulatory Background

The New Mexico Environmental Department (NMED) finalized the Ozone Precursor rule under 20.2.50 NMAC to reduce ozone emissions at sources causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard for ozone. Sources located in Chaves, Dona Ana, Eddy, Lea, Rio Arriba, Sandoval, San Juan, and Valencia counties are subject to the rule.

In lieu of meeting the emission standards established under 20.2.50.113 for portable and stationary natural gas-fired combustion turbines, owners and operators may submit a request for alternative emission standards for a specific engine or turbine based on technical impracticability or economic infeasibility. The purpose of this report is to meet the requirement from 20.2.50.113(11)(a) as follows:

> *"The owner or operator may submit a request for alternative emission standards for a specific engine or turbine based on technical impracticability or economic infeasibility. The owner or operator is not required to submit an ACP proposal under Paragraph (10) of Subsection B of 20.2.50.113 NMAC prior to submission of a request for alternative emissions standards under this Paragraph (11), provided that the owner or operator satisfies Subparagraph (b) of Paragraph (11) of Subsection B of 20.2.50.113 NMAC, below. To qualify for an alternative emission standard, an owner or operator must comply with the following requirements:*
>
> *(a) Prepare a reasonable demonstration detailing why it is not technically practicable or economically feasible for the individual engine or turbine to achieve the emissions standards in table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC or table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC, as applicable."*
>
> *(b) Prepare a demonstration detailing why emissions from individual engine or turbine cannot be addressed through an ACP in a technically practicable or economically feasible manner;*
>
> *(c) Prepare a technical analysis for the affected engine or turbine specifying the emission reductions that can be achieved through other means, such as combustion modifications or capacity limitations.*

2.2 Turbine Information

EPNG owns and operates ten stationary natural gas-fired combustion turbines with a maximum design rating equal to or greater than 1,000 hp as summarized in Table 2-1.

Table 2-1 EPNG Sources Included in Cost Analysis

Engine Location	Unit No.	Turbine Manufacturer	Turbine Model	Permitted Turbine Rating (hp)	Hourly Permit Limit	Annual Permit Limit
Afton	A-01	GE	MS3712R-A	6,150	51.3 pph	224.5 tpy
Afton	A-02	GE	MS3712R-A	6,150	51.3 pph	224.5 tpy
Afton	A-03	GE	MS3712R-A	6,150	51.3 pph	224.5 tpy
Belen	A-01	GE	MS3572R-C	4,737	38.6 pph	169.0 tpy
Belen	A-02	GE	MS3572R-C	4,737	38.6 pph	169.0 tpy
Caprock	A-01	GE	MS3702R-C	6,026	45.9 pph	201.0 tpy
Caprock	A-02	GE	MS3572R-C	4,879	39.3 pph	172.1 tpy
Pecos River	A-01	GE	MS3712R-A	7,150	53.1 pph	232.6 tpy
Pecos River	A-02	GE	MS3712R-A	7,150	53.1 pph	232.6 tpy
Pecos River	A-03	GE	MS3712R-A	7,150	53.1 pph	232.6 tpy

Out of all of the company-owned units impacted by the Ozone Precursor Rule, the turbine units in Table 2.1 account for over half of the total permitted NOx emissions. Emissions from turbine units in the above table cannot be addressed through an ACP in a technically practicable or economically feasible manner, based on technical and cost analyses presented in Sections 3 and 4. Capacity limitations are also infeasible due to legal obligations under the Federal Energy Regulatory Commission (FERC), which require units to remain active and able to provide a sufficient level of horsepower for compression and subsequent transportation of pipeline quality gas for communities, public institutions, and businesses. The turbine units in Table 2.1 have not undergone prior modifications that would constitute the definition of reconstruction; units are not subject to Federal new source performance standards.

3 Potential Control Technologies Review

Potential control technologies and their feasibility are discussed in Section 3.1. The technical feasibility of the available control technologies is summarized in Section 3.2.

3.1 Potentially Available Control Technologies and Technical Feasibility Evaluation

Potentially available control technologies to reduce NO_X from the stationary natural gas-fired combustion turbines are summarized below. The technical feasibility of installation of each control technology is also evaluated for the ten turbines.

3.1.1 Water or Steam Injection

Water or steam injection operates by introducing water or steam into the flame area of the gas turbine combustor. The injected fluid provides a heat sink that absorbs some of the heat of combustion, thereby reducing the peak flame temperature and the formation of thermal NO_X. The water injected into the turbine must be of high purity such that no dissolved solids are injected into the turbine. Dissolved solids in the water may damage the turbine due to corrosion and/or the formation of deposits in the hot section of the turbine. The requirement of high-purity water can be expensive to retrofit because EPNG does not have water treatment systems on-site. Moreover, the consumption of water can be very high for a large turbine. Such high water usage may pose problems for the local water supply and is an added expense. This is important, especially in dry regions such as New Mexico. Although water/steam injection acts to reduce NO_X emissions, the lower average temperature within the combustor may produce higher levels of CO and hydrocarbons because of incomplete combustion. Additionally, water/stream injection results in a decrease in combustion efficiency and an increase in maintenance requirements due to wear on the turbine and combustor.

The ten turbines included in this request are GE Frame 3 turbines. Based on GE representative feedback, water or steam injection technology is not available to the GE Frame 3 gas turbines. This NO_x control method is not technically feasible.

3.1.2 Lean Head End Combustion Liner Upgrade and Dry Low-NOX (DLN) Combustors

The liner of a turbine surrounds the combustion process and allows for various airflows to pass through into the combustion zone. The liner is subject to high temperatures due to the combustion process which it contains. Because of this, the life of the liner is limited. Replacing the old combustion liner with a new, upgraded liner is a common retrofit. Combustion liners have a limited lifespan and are designed to be replaced.

Lean pre-mix technology, also referred to as dry low-NOX (DLN) combustion technology, is a pollution prevention technology that controls NO_X emissions. DLN inhibits the conversion of atmospheric nitrogen to NO_X in the turbine combustor. This is accomplished by reducing the combustor temperature using lean mixtures of air and/or fuel staging or by decreasing the residence time of the combustor through combustion chamber design. For existing turbines, the combustion chamber would need to be redesigned and reconfigured to allow for lean pre-mixing or fuel staging.

In lean combustion systems, excess air is introduced into the combustion zone to produce a significantly leaner fuel/air mixture than is required for complete combustion. This excess air reduces the overall flame temperature because a portion of the energy released from the fuel must be used to heat the excess air to the reaction temperature. Pre-mixing the fuel and air prior to introduction into the combustion zone provides a uniform fuel/air mixture and prevents localized high-temperature regions within the combustor area. The fuel-to-air ratio must be maintained within a relatively narrow range to obtain low NO_X without blowout and without increasing carbon monoxide (CO) emissions, which are generated during incomplete combustion.[1] Since NO_X formation rates are an exponential function of temperature, turbines having frequent and rapid load changes may experience a brief spike in NO_X emissions with DLN technology.

Based upon feedback from GE representative, , DLN control technology combined with a liner upgrade is not available to GE Frame 3 Models A and C turbines; therefore, this is not a technically feasible technology.

3.1.3 EM_X/$SCONO_X$

EM_X™ (the second generation of the $SCONO_X$ NO_X Absorber Technology) utilizes a coated oxidation catalyst to remove both NO_X and CO without a reagent, such as NH_3. Hydrogen (H_2) is used as the basis for the proprietary catalyst regeneration process. The $SCONO_X$ system consists of a platinum-based catalyst coated with potassium carbonate to oxidize NO and CO. The NO_2 molecules are subsequently absorbed on the treated surface of the $SCONO_X$ catalyst. The catalyst is installed in the flue gas with a temperature range between 300°F to 700°F.[2]

The EM_X™/$SCONO_X$™ catalyst system is designed to operate effectively at temperatures ranging from 300 to 700 °F. The turbines at EPNG have an exhaust temperature of approximately 850-950°F.[3]

EM_X™/$SCONO_X$™ applications on turbines with outlet temperatures this high have not been identified. Consequently, it is concluded that EM_X™/$SCONO_X$™ is not technically feasible for the control of NO_X emissions from the turbines.

3.1.4 Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is a post-combustion gas treatment process in which urea or ammonia (NH_3) is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, ammonia and nitric oxide (NO) react to form diatomic nitrogen and water vapor. The chemical reactions can be expressed as:

$$4\,NO + 4\,NH_3 + O_2 \rightarrow 4\,N_2 + 6\,H_2O$$
$$2\,NO_2 + 4\,NH_3 \rightarrow 3\,N_2 + 6\,H_2O$$

[1] "Retrofitability of DLN/DLE system," GE Technology Insights 2013.
[2] BACT Analysis for JEA-Greenland Energy Center Units 1 and 2, Combined Cycle Combustion Turbines. Prepared by Black & Veatch (September 2008).
[3] Per average of 2016, 2017, and 2018 emissions test summaries.

When operated within the optimum temperature range, the reaction can result in removal efficiencies of 90 percent.[4] In order for the SCR system to function properly, the exhaust gas must be within a particular temperature range (typically between 450 and 850 °F), dependent on the material of the catalyst. SCR units have the ability to function effectively under fluctuating temperature conditions, although fluctuation in exhaust gas temperature reduces removal efficiency slightly by disturbing the NH_3/NO_X molar ratio. SCR installations typically have an operating range of 450 to 850ºF. The exhaust temperatures of the turbines included in this evaluation are approximately 850-950ºF, which is higher than the typical SCR operating range. SCRs may operate at higher temperatures but this generally results in lower efficiencies (between 70-85%).[5] SCR is therefore considered technically feasible.

It should be noted that there are several operational issues that may inhibit the effectiveness of SCR as a control option for turbines at natural gas compressor stations. The NH_3/NO_X molar ratio of 1:1 must be carefully controlled to allow for optimum NO_X reduction while limiting the amount of unreacted NH_3 emitted to the atmosphere (known as "ammonia slip"). This ratio is difficult to control in units that have the variable loads experienced at compressor stations. The unit loading and speed of the turbines fluctuate continually according to the time of day, changes in the weather, and customer demands. Throughout the day, units are started and stopped, and loads are changed to keep pipeline operating pressures within safe operating parameters and keep volumes sufficient to meet customer obligations. Although the variable nature of compressor station turbine loads does not make SCR operation technically infeasible, the inherent lag between CEM sampling and ammonia injection for the turbines may cause hourly NO_X emission limits to be exceeded during periods of increased load and unreacted NH_3 emissions ("ammonia slip") to increase during periods of load loss.

3.1.5 Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion NO_X control technology based on the reaction of urea or ammonia with NO_X. In the SNCR chemical reaction, urea $[CO(NH_2)_2]$ or ammonia is injected into the combustion gas path to reduce the NO_x to nitrogen and water. The overall reaction schemes for both urea and ammonia systems can be expressed as follows:

$$CO(NH_2)_2 + 2\ NO + \tfrac{1}{2}\ O_2 \rightarrow 2\ N_2 + CO_2 + 2\ H_2O$$
$$4\ NH_3 + 6NO \rightarrow 5\ N_2 + 6\ H_2O$$

Typical removal efficiencies for SNCR range from 40 to 60 percent.[6] An important consideration for implementing SNCR is the operating temperature range. The optimum temperature range is approximately 1,600 to 2,000°F.[7] Operation at temperatures below this range results in ammonia slip

[4] U.S. EPA, Office of Air Quality Planning and Standards. OAQPS Control Cost Manual Section 4-2 Chapter 2, updated on June 12, 2019.

[5] U.S. EPA, Office of Air Quality Planning and Standards. OAQPS Control Cost Manual Section 4-2 Figure 2.2, updated on June 12, 2019.

[6] U.S. EPA, Office of Air Quality Planning and Standards. OAQPS Control Cost Manual Section 4-2 Chapter 1, updated on April 25, 2019.

[7] U.S. EPA, Clean Air Technology Center. Oxides of nitrogen (NOX), Why and How They Are Controlled. Research Triangle Park, North

(when non-reacted NH_3 is emitted to the atmosphere). The temperature range required for the effective operation of this technology is above the peak exhaust temperature for the GE gas turbines assessed here. For this reason, it has been determined that this control technology is not feasible for the GE gas turbines at EPNG facilities.

3.1.6 Good Combustion Practices (base case)

NO_X emissions are caused by the oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the combustion chamber, where pockets of excess oxygen occur. By following concepts from engineering knowledge, experience, and manufacturer's recommendations, good combustion practices for the operation of the units can be developed and maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for the equipment involved, and using pipeline quality natural gas. By maintaining good combustion practices, the unit will operate as intended with the lowest NO_X emissions.

Utilizing good combustion practices and fuel selection were identified in this review for the control of NO_X emissions from combustion turbines; therefore, it has been determined that this method of NO_X control is feasible for the GE gas turbines at EPNG facilities. EPNG has developed Turbine Inspection and Maintenance Schedules Best Practices procedures, which are based on manufacturer recommendations, and EPNG has systems in place to ensure that its turbines are operated and maintained in accordance with these procedures. These practices are currently in use at all facilities, and the PTE is reflective of operations following good combustion practices. No further assessment of these control practices is included in this report.

3.2 Technical Feasibility Summary

The technical feasibility of potential control technologies is summarized in Table 3-1.

Table 3-1 Technical Feasibility of NO_X Emission Control Technologies for EPNG Turbines

Section	Technology	Technically Feasible?
3.1.1	Water or Steam Injection	No
3.1.2	Lean Head End Combustion Liner Upgrade and Dry Low-NOX (DLN) Combustors	No
3.1.3	EM_X/$SCONO_X$	No
3.1.4	SCR	Yes
3.1.5	SNCR	No
3.1.6	Good Combustion Practices	Yes

Carolina. p. 18, EPA-456/F-99-006R, November 1999.

4 Cost Analysis

4.1 Cost of Compliance

Economic impacts were analyzed using vendor cost estimates along with the procedures found in the EPA Air Pollution Control Cost Manual (CCM) as applicable. The sources of the control equipment cost data are noted in each of the control cost analysis worksheets in Appendix A-1.

Overall, cost-effectiveness is evaluated on a dollar-per-ton ($/ton) basis using the annual operating cost ($/year) divided by the annual emission reduction achieved by the control device (ton/yr). The initial capital cost was annualized over a 25-year period and added to the annual operating costs, and the interest rate reflects EPNG's actual cost of borrowing. To be conservative in the cost analysis, the highest actual performance test data plus 20% safety factor and 8,760 annual operating hours are used to calculate the annual emission reduction rates. EPNG compared the cost-effectiveness to a $7,500/ton threshold to evaluate if the control is economically feasible.[8]This cost threshold is cited in the preamble to rulemaking for 20.2.50 NMAC and has been utilized by other states to define an acceptable level for determination of cost effectiveness for control technologies.

4.1.1 Proposed Alternative Emission Rates

Under 20.2.50.113(11), the Ozone Precursor rule states an owner or operator may submit a request for alternative emission standards for a specific engine or turbine based on technical impracticability or economic infeasibility.

EPNG expects the turbine operation in the future to be similar to current operations. However, turbine operation is highly dependent on product demand, weather patterns, pipeline maintenance, and upstream/downstream pipeline impacts. These factors create a considerable amount of uncertainty as to the expected annual operating hours of each turbine for a specific year, so to be conservative in establishing Alternative Emissions Standards (AES), the operating hours were assumed to be 8,760 hours per year. EPNG calculated the AES using the highest NOx hourly performance test data for each model with a 20% safety factor and 8,760 operating hours per year. The resulting emissions are lower than permitted emissions for each turbine but are more representative of the physical and operational design at the locations these turbines are installed.

EPNG is proposing to accept these AES as enforceable emission limitations The proposed hourly and annual AES for each turbine is presented in Table 4-1.

[8] New Mexico Environmental Improvement Board No. EIB 21-27(R), In the Matter of Proposed New Regulation, 20.2.50 NMAC – *Oil and Gas Sector – Ozone Precursor Pollutants*, p. 111.

Table 4-1 Proposed Alternative Emissions Standards For NOx

Turbine Location	Unit No.	Proposed Hourly NOx Emissions	Proposed Annual NO_x Emissions
Afton	A-01	46.0 pph	201.5 tpy
Afton	A-02	46.0 pph	201.5 tpy
Afton	A-03	46.0 pph	201.5 tpy
Belen	A-01	20.9 pph	91.5 tpy
Belen	A-02	20.9 pph	91.5 tpy
Caprock	A-01	41.2 pph	180.5 tpy
Caprock	A-02	20.9 pph	91.6 tpy
Pecos River	A-01	46.0 pph	201.5 tpy
Pecos River	A-02	46.0 pph	201.5 tpy
Pecos River	A-03	46.0 pph	201.5 tpy

4.1.2 Control Cost Effectiveness Evaluation

The details of the turbine control cost effectiveness evaluation are included in Appendix A-1. The findings of the economic analysis are summarized in Table 4-2.

Table 4-2 Cost Effectiveness of SCR for the Turbines

Turbine Location	Unit No.	Emission Reduction (ton/year)	Cost Effectiveness ($/ton NO_x Removed)	Cost Effective?
Afton	A-01	152.2 tpy	$11,697	No
Afton	A-02	152.2 tpy	$11,097	No
Afton	A-03	152.2 tpy	$11,097	No
Belen	A-01	57.8 tpy	$30,794	No
Belen	A-02	57.8 tpy	$29,214	No
Caprock	A-01	126.6 tpy	$9,933	No
Caprock	A-02	57.9 tpy	$29,283	No
Pecos River	A-01	152.2 tpy	$8,261	No
Pecos River	A-02	152.2 tpy	$11,097	No
Pecos River	A-03	152.2 tpy	$11,097	No

Based on the information provided in Table 4-1, SCR was not considered to be cost-effective for the turbines owned by EPNG.

Appendix A-1

Control Cost Estimate for El Paso Natural Gas Company Turbines

El Paso Natural Gas Company, LLC

Afton Compressor Station - 50 ppmvd NOx based on PTE

Unit: A-01	Interest Rate:	8.53%	<-- EPNG Actual Interest Rate
GE Model M3712R Turbine	Period (yrs):	25	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_x lb/hr:		46.00 lb/hr	<--highest actual test data for GE M3712R-A plus 20% safety factor
NO_x tpy:		201.48 tpy	<-- Calculated using the highest actual test data plus 20% and 8760 operating hours.
SCR			
NO_x Reduction:		75.5%	<-- Reach the 50 ppmc Nox limit
NO_x lb/hr:		11.25 lb/hr	<-- Based on highest test result of GE M3712R-A at equivalent reduction to 50 ppmvd.
NO_x tpy:		49.28 tpy	<-- Expected annual NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-	<-- Presumed to be included in CE2107005 shown below (Emission Controls CWIP)
SCR Capital Investment	$	13,258,524	<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP)
Total Capital Investment	$	13,258,524	
Annualized TCI:	$	1,298,747	<-- Based on interest rate, year and TCI
Annual Administrative Costs:	$	3,424	<-- Based on 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost)
Annual O&M Costs:	$	478,225	<-- Annual Cost Estimate (A-01)
Total Annual Costs:	$	1,780,396	
Emissions Reduction:		152.2 tpy	
Cost Effectiveness:	$	11,697.36 $/ton	

Afton Unit A-01: Cost Estimate

Total Capital Investment (TCI) =	$ 13,258,524

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$478,225
Indirect Annual Costs (IDAC) =	$1,302,171
Total annual costs (TAC) = DAC + IDAC	$1,780,396

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI	$66,293	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	
Annual Reagent Cost =	Reagent Consumption Rate/Hour x Cost of R_{eagent} x Operating Hours/Year =	$218,124	Vendor quote - $2.49/gal of aqueous ammonia delivered to site; Per vendor 6/9/2022 email, at 100% full load, ammoniaconsumption rate is approximately 10 gph
Annual Electricity Cost =	Electricity Consumption Rate x Cost of $E_{lectricity}$ x Operating Hours/Year =	$29,609	Vendor quote - 50 kW, Default rate of $0.0676/kWh and 8760 hrs used in the calculation
Annual Catalyst Replacement Cost =	Catalyst replacement cost $ x FWF =	$76,600	Catalyst replacement cost = $250,000 per vendor, FWF = 0.3064 based on 24,000 hr catalyst life and 8.53% interest rate.
Direct Annual Cost =		$478,225	

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,424
Capital Recovery Costs (CR)=	CRF x TCI =	$1,298,747
Indirect Annual Cost (IDAC) =	AC + CR =	$1,302,171

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,780,396 Per Year
NOx Removed =	152.2 tons/year
Cost Effectiveness =	$11,697.36

El Paso Natural Gas Company, LLC

Afton Compressor Station - 50 ppmvd NOx based on PTE

Unit: A-02	Interest Rate:	8.53% <-- EPNG Actual Interest Rate
GE Model M3712R Turbine	Period (yrs):	25 <-- EPA Air Pollution Control Cost Manual
Base Case		
NO_x lb/hr:	46.00 lb/hr	<--highest actual test data for GE M3712R-A plus 20% safety factor
NO_x tpy:	201.48 tpy	<-- Calculated using the highest actual test data plus 20% and 8760 operating hours.
SCR		
NO_x Reduction:	75.5%	<-- Reach the 50 ppmc Nox limit
NO_x lb/hr:	11.25 lb/hr	<-- Based on highest test result of GE M3712R-A at equivalent reduction to 50 ppmvd.
NO_x tpy:	49.28 tpy	<-- Expected annual NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$ -	<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$ 12,371,394	<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP) +$1MM cost increase
Total Capital Investment	$ 12,371,394	
Annualized TCI:	$ 1,211,848	<-- Based on interest rate, year and TCI
Annual Administrative Costs:	$ 3,370	<-- Based on 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost)
Annual O&M Costs:	$ 473,790	<-- Annual Cost Estimate (A-02)
Total Annual Costs:	$ 1,689,008	
Emissions Reduction:	152.2 tpy	
Cost Effectiveness:	$ 11,096.93 $/ton	

Afton Unit A-02: Cost Estimate

Total Capital Investment (TCI) =	$ 12,371,394

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$473,790
Indirect Annual Costs (IDAC) =	$1,215,218
Total annual costs (TAC) = DAC + IDAC	$1,689,008

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI	$61,857	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	
Annual Reagent Cost =	Reagent Consumption Rate/Hour x Cost of R_{eagent} x Operating Hours/Year =	$218,124	Vendor quote - $2.49/gal of aqueous ammonia delivered to site; Per vendor 6/9/2022 email, at full load, ammonia cobsumption rate is approximately 10 gph
Annual Electricity Cost =	Electricity Consumption Rate x Cost of $E_{lectricity}$ x Operating Hours/Year =	$29,609	Vendor quote - 50 kW, Default rate of $0.0676/kWh and 8760 hrs used in the calculation
Annual Catalyst Replacement Cost =	Catalyst replacement cost $ x FWF =	$76,600	Catalyst replacement cost = $250,000 per vendor, FWF = 0.3064 base on 24,000 hr catalyst life and 8.53% interest rate.
Direct Annual Cost =		$473,790	

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,370
Capital Recovery Costs (CR)=	CRF x TCI =	$1,211,848
Indirect Annual Cost (IDAC) =	AC + CR =	$1,215,218

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,689,008 Per Year
NOx Removed =	152.2 tons/year
Cost Effectiveness =	$11,096.93

El Paso Natural Gas Company, LLC

Afton Compressor Station - 50 ppmvd NOx based on PTE

Unit: A-03	Interest Rate:	8.53%	<-- EPNG Actual Interest Rate
GE Model M3712R Turbine	Period (yrs):	25	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_x lb/hr:		46.00 lb/hr	<--highest actual test data for GE M3712R-A plus 20% safety factor
NO_x tpy:		201.48 tpy	<-- Calculated using the highest actual test date plus 20% and 8760 operating hours.
SCR			
NO_x Reduction:		75.5%	<-- Reach the 50 ppmc Nox limit
NO_x lb/hr:		11.25 lb/hr	<-- Based on highest test result of GE M3712R-A at equivalent reduction to 50 ppmvd.
NO_x tpy:		49.28 tpy	<-- Expected annual NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-	<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$	12,371,394	<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP) +$1 MM cost increase per vendor
Total Capital Investment	$	12,371,394	
Annualized TCI:	$	1,211,848	<-- Based on interest rate, year and TCI
Annual Administrative Costs:	$	3,370	<-- Based on 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost)
Annual O&M Costs:	$	473,790	<-- Annual Cost Estimate (A-03)
Total Annual Costs:	$	1,689,008	
Emissions Reduction:		152.2 tpy	
Cost Effectiveness:	$	11,096.93 $/ton	

Afton Unit A-03: Cost Estimate

Total Capital Investment (TCI) =	$ 12,371,394

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$473,790
Indirect Annual Costs (IDAC) =	$1,215,218
Total annual costs (TAC) = DAC + IDAC	$1,689,008

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI	$61,857	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	
Annual Reagent Cost =	Reagent Consumption Rate/Hour x Cost of R_{eagent} x Operating Hours/Year =	$218,124	Vendor quote - $2.49/gal of aqueous ammonia delivered to site; Per vendor 6/9/2022 email, at full load, ammonia consumption rate is approximately 10 gph
Annual Electricity Cost =	Electricity Consumption Rate x Cost of $E_{lectricity}$ x Operating Hours/Year =	$29,609	Vendor quote - 50 kW, Default rate of $0.0676/kWh and 8760 hrs used in the calculation
Annual Catalyst Replacement Cost =	Catalyst replacement cost $ x FWF =	$76,600	Catalyst replacement cost = $250,000 per vendor, FWF = 0.3064 based on 24,000 hr catalyst life and 8.53% interest rate.
Direct Annual Cost =		$473,790	

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,370
Capital Recovery Costs (CR)=	CRF x TCI =	$1,211,848
Indirect Annual Cost (IDAC) =	AC + CR =	$1,215,218

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,689,008 Per Year
NOx Removed =	152.2 tons/year
Cost Effectiveness =	$11,096.93

El Paso Natural Gas Company, LLC
Belen Compressor Station - 50 ppmvd NOx based on PTE

Unit: A-01	Interest Rate:	8.53%	<-- EPNG Actual Interest Rate
GE Model M3572R Turbine	Period (yrs):	25	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_x lb/hr:	20.90 lb/hr		<--highest actual test date for GE M3572R-C plus 20% safety factor
NO_x tpy:	91.54 tpy		<-- Calculated using the highest actual test data plus 20% and 8760 operating hours.
SCR			
NO_x Reduction:	63.2%		<-- Reach the 50 ppmc NOx limit
NO_x lb/hr:	7.70 lb/hr		<-- Based on highest test result of GE M3572R-C at equivalent reduction to 50 ppmvd.
NO_x tpy:	33.73 tpy		<-- Expected annual NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$ -		<-- Presumed to be included in CE2107005 shown below (Emission Controls CWIP)
SCR Capital Investment	$ 13,258,524		<-- CE2107005 Caprock internal est 07/16/2021 + $1 MM cost increase per vendor June 2022 letter
Total Capital Investment	$ 13,258,524		
Annualized TCI:	$ 1,298,747		<-- Based on interest rate, year and TCI
Administrative Costs:	$ 3,424		<--Based on 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost)
Annual O&M Costs:	$ 478,225		<-- Annual Cost Estimate (A-01)
Total Annual Costs:	$ 1,780,396		
Emissions Reduction:	57.8 tpy		
Cost Effectiveness:	**$ 30,794.18**	**$/ton**	

Belen Unit A-01: Cost Estimate

Total Capital Investment (TCI) =	$ 13,258,524

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$478,225
Indirect Annual Costs (IDAC) =	$1,302,171
Total annual costs (TAC) = DAC + IDAC	$1,780,396

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI	$66,293	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	
Annual Reagent Cost =	Reagent Consumption Rate/Hour x Cost of R_{eagent} x Operating Hours/Year =	$218,124	Vendor quote - $2.49/gal of aqueous ammonia delivered to site; Per vendor 6/9/2022 email, at 100% full load, ammonia consumption rate is approximately 10 gph
Annual Electricity Cost =	Electricity Consumption Rate x Cost of $E_{lectricity}$ x Operating Hours/Year =	$29,609	Vendor quote - 50 kW, Default rate of $0.0676/kWh and 8760 hrs used in the calculation
Annual Catalyst Replacement Cost =	Catalyst replacement cost $ x FWF =	$76,600	Catalyst replacement cost = $250,000 per vendor, FWF = 0.3064 based on 24,000 hr catalyst life and 8.53% interest rate.
Direct Annual Cost =		$478,225	

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,424
Capital Recovery Costs (CR)=	CRF x TCI =	$1,298,747
Indirect Annual Cost (IDAC) =	AC + CR =	$1,302,171

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,780,396 Per Year
NOx Removed =	57.8 tons/year
Cost Effectiveness =	$30,794.18

El Paso Natural Gas Company, LLC

Belen Compressor Station - 50 ppmvd NOx based on PTE

Unit: A-02	Interest Rate:	8.53%	<-- EPNG Actual Interest Rate
GE Model M3572R Turbine	Period (yrs):	25	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_x lb/hr:		20.90 lb/hr	<--highest actual test date for GE M3572R-C plus 20% safety factor
NO_x tpy:		91.54 tpy	<-- Calculated using the highest actual test data plus 20% and 8760 operating hours.
SCR			
NO_x Reduction:		63.2%	<-- Reach the 50 ppmc NOx limit
NO_x lb/hr:		7.70 lb/hr	<-- Based on highest test result of GE M3572R-C at equivalent reduction to 50 ppmvd.
NO_x tpy:		33.73 tpy	<-- Expected annual NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-	<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$	12,371,394	<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP) + $1 MM cost increase per vendor
Total Capital Investment	$	12,371,394	
Annualized TCI:	$	1,211,848	<-- Based on interest rate, year and TCI
Administrative Costs:	$	3,370	<--Based on 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost)
Annual O&M Costs:	$	473,790	<-- Annual Cost Estimate (A-02)
Total Annual Costs:	$	1,689,008	
Emissions Reduction:		57.8 tpy	
Cost Effectiveness:	**$**	**29,213.50 $/ton**	

Belen Unit A-02: Cost Estimate

Total Capital Investment (TCI) =	$ 12,371,394

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$473,790
Indirect Annual Costs (IDAC) =	$1,215,218
Total annual costs (TAC) = DAC + IDAC	$1,689,008

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI	$61,857	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	
Annual Reagent Cost =	Reagent Consumption Rate/Hour x Cost of R_{eagent} x Operating Hours/Year =	$218,124	Vendor quote - $2.49/gal of aqueous ammonia delivered to site; Per vendor 6/9/2022 email, at 100% full load, ammonia consumption rate is approximately 10 gph
Annual Electricity Cost =	Electricity Consumption Rate x Cost of $E_{lectricity}$ x Operating Hours/Year =	$29,609	Vendor quote - 50 kW, Default rate of $0.0676/kWh and 8760 hrs used in the calculation
Annual Catalyst Replacement Cost =	Catalyst replacement cost $ x FWF =	$76,600	Catalyst replacement cost = $250,000 per vendor, FWF = 0.3064 based on 24,000 hr catalyst life and 8.53% interest rate.
Direct Annual Cost =		$473,790	

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,370
Capital Recovery Costs (CR)=	CRF x TCI =	$1,211,848
Indirect Annual Cost (IDAC) =	AC + CR =	$1,215,218

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,689,008 Per Year
NOx Removed =	57.8 tons/year
Cost Effectiveness =	$29,213.50

El Paso Natural Gas Company, LLC

Caprock Compressor Station - 50 ppmvd NOx based on PTE

Unit: A-01	Interest Rate:	8.53%	<-- EPNG Actual Interest Rate
GE Model M3702R Turbine	Period (yrs):	25	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_x lb/hr:		41.20 lb/hr	<--highest actual test data for GE M3702R-C plus 20% safety factor
NO_x tpy:		180.46 tpy	<-- Calculated using the highest actual test data plus 20% and 8,760 operating hours per year.
SCR			
NO_x Reduction:		70.1%	<-- Reach the 50 ppmc Nox limit
NO_x lb/hr:		12.30 lb/hr	<-- Based on highest test result of GE M3702R-C at equivalent reduction to 50 ppmvd.
NO_x tpy:		53.87 tpy	<-- Expected annual NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-	<-- Presumed to be included in CE2107005 shown below (Emission Controls CWIP)
SCR Capital Investment	$	8,180,921	<-- CE2107005 Caprock internal est 07/16/2021 + $1MM per vendor June 2022 letter for 25% cost increase
Total Capital Investment	$	8,180,921	
Annualized TCI:	$	801,367	<-- Based on interest rate, year and TCI
Administrative Costs:	$	3,119	<--Based on 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost)
Annual O&M Costs:	$	452,837	<-- Annual Cost Estimate (A-01)
Total Annual Costs:	$	1,257,324	
Emissions Reduction:		126.6 tpy	
Cost Effectiveness:	**$**	**9,932.88 $/ton**	

Caprock Unit A-01: Cost Estimate

Total Capital Investment (TCI) =	$ 8,180,921

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$452,837
Indirect Annual Costs (IDAC) =	$804,486
Total annual costs (TAC) = DAC + IDAC	$1,257,324

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI	$40,905	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	
Annual Reagent Cost =	Reagent Consumption Rate/Hour x Cost of $R_{reagent}$ x Operating Hours/Year =	$218,124	Vendor quote - $2.49/gal of aqueous ammonia delivered to site; Per vendor 6/09/22 quote, at 100% full load, ammonia consumption rate is approximately 10 gph
Annual Electricity Cost =	Electricity Consumption Rate x Cost of $E_{electricity}$ x Operating Hours/Year =	$29,609	Default rate of $0.0676/kWh and 8760 hrs used in the calculation
Annual Catalyst Replacement Cost =	Catalyst replacement cost $ x FWF =	$76,600	Catalyst replacement cost = $250,000 per vendor, FWF = 0.3064 based on 24,000 hr catalyst life and 8.53% interest rate.
Direct Annual Cost =		$452,837	

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,119
Capital Recovery Costs (CR)=	CRF x TCI =	$801,367
Indirect Annual Cost (IDAC) =	AC + CR =	$804,486

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,257,324 Per Year
NOx Removed =	126.6 tons/year
Cost Effectiveness =	$9,932.88

El Paso Natural Gas Company, LLC

Caprock Compressor Station - 50 ppmvd NOx based on PTE

Unit: A-02	Interest Rate:	8.53%	<-- EPNG Actual Interest Rate
GE Model M3572R Turbine	Period (yrs):	25	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_x lb/hr:		20.92 lb/hr	<--highest actual test data for GE M3572R-C plus 20% safety factor
NO_x tpy:		91.61 tpy	<-- Calculated using the highest actual test data plus 20% and 8,760 operating hours per year.
SCR			
NO_x Reduction:		63%	<-- Reach the 50 ppmvd NOx limit
NO_x lb/hr:		7.70 lb/hr	<-- Based on highest test result of GE M3572R-C at equivalent reduction to 50 ppmvd.
NO_x tpy:		33.73 tpy	<-- Expected annual NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-	<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$	12,430,361	<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP) plus $1MM cost increase per vendor
Total Capital Investment	$	12,430,361	
Annualized TCI:	$	1,217,624	<-- Based on interest rate, year and TCI
Administrative Costs:	$	3,374	<--Based on 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost)
Annual O&M Costs:	$	474,085	<-- Annual Cost Estimate (A-02)
Total Annual Costs:	$	1,695,083	
Emissions Reduction:		57.9 tpy	
Cost Effectiveness:	**$**	**29,283.08 $/ton**	

Caprock Unit A-02: Cost Estimate

Total Capital Investment (TCI) =	$ 12,430,361

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$474,085
Indirect Annual Costs (IDAC) =	$1,220,998
Total annual costs (TAC) = DAC + IDAC	$1,695,083

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI	$62,152	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	
Annual Reagent Cost =	Reagent Consumption Rate/Hour x Cost of R_{eagent} x Operating Hours/Year =	$218,124	Vendor quote - $2.49/gal of aqueous ammonia delivered to site; Per ArieNox 6/09/22 quote, at 100% full load, ammonia consumption rate is approximately 10 gph
Annual Electricity Cost =	Electricity Consumption Rate x Cost of $E_{lectricity}$ x Operating Hours/Year =	$29,609	Vendor quote - 50 kW, Default rate of $0.0676/kWh and 8760 hrs used in the calculation
Annual Catalyst Replacement Cost =	Catalyst replacement cost $ x FWF =	$76,600	Catalyst replacement cost = $250,000 per vendor, FWF = 0.3064 based on 24,000 hr catalyst life and 8.53% interest rate.
Direct Annual Cost =		$474,085	

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,374
Capital Recovery Costs (CR)=	CRF x TCI =	$1,217,624
Indirect Annual Cost (IDAC) =	AC + CR =	$1,220,998

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,695,083	Per Year
NOx Removed =	57.9	tons/year
Cost Effectiveness =	$29,283.08	

El Paso Natural Gas Company, LLC

Pecos River Compressor Station - 50 ppmv NOx based on PTE

A-01	Interest Rate:	8.53%	<-- EPNG Actual Interest Rate
GE Model M3712R Turbine	Period (yrs):	25	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_x lb/hr:		46.00 lb/hr	<--Highest actual test data for GE M3712R-A plus 20% safety factor
NO_x tpy:		201.48 tpy	<-- Calculated using the highest actual test date plus 20% and 8760 operating hours.
SCR			
NO_x Reduction:		75.5%	<-- Reach the 50 ppmvd NOx limit
NO_x lb/hr:		11.25 lb/hr	<-- Based on highest test result of GE M3712R-A at equivalent reduction to 50 ppmvd.
NO_x tpy:		49.28 tpy	<-- Expected annual NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-	<-- Presumed to be included in CE2107005 shown below (Emission Controls CWIP)
SCR Capital Investment	$	8,180,921	<-- CE2107005 Caprock internal est 07/16/2021 + $1 MM (Vendor's June 2022 email indicate cost increase of 25% from the 2021 quote)
Total Capital Investment	$	8,180,921	
Annualized TCI:	$	801,367	<-- Based on interest rate, year and TCI
Administrative Costs:	$	3,119	<--Based on 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost)
Annual O&M Costs:	$	452,837	<-- Annual Cost Estimate (A-01)
Total Annual Costs:	$	1,257,324	
Emissions Reduction:		152.2 tpy	
Cost Effectiveness:	$	8,260.73 $/ton	

Pecos River Unit A-01:Cost Estimate

Total Capital Investment (TCI) =	$ 8,180,921

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$452,837
Indirect Annual Costs (IDAC) =	$804,486
Total annual costs (TAC) = DAC + IDAC	$1,257,324

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI	$40,905	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	
Annual Reagent Cost =	Reagent Consumption Rate/Hour x Cost of R_{eagent} x Operating Hours/Year =	$218,124	Vendor quote - $2.49/gal of aqueous ammonia delivered to site; Per vendor 6/9/2022 email, at 100% full load, ammonia consumption rate is approximately 10 gph
Annual Electricity Cost =	Electricity Consumption Rate x Cost of $E_{lectricity}$ x Operating Hours/Year =	$29,609	Vendor quote - 50 kW, Default rate of $0.0676/kWh and 8760 hrs used in the calculation
Annual Catalyst Replacement Cost =	Catalyst replacement cost $ x FWF =	$76,600	Catalyst replacement cost = $250,000 per vendor, FWF = 0.3064 based on 24,000 hr catalyst life and 8.53% interest rate.
Direct Annual Cost =		$452,837	

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,119
Capital Recovery Costs (CR)=	CRF x TCI =	$801,367
Indirect Annual Cost (IDAC) =	AC + CR =	$804,486

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,257,324 Per Year
NOx Removed =	152.2 tons/year
Cost Effectiveness =	$8,260.73

El Paso Natural Gas Company, LLC

Pecos River Compressor Station - 50 ppmvd NOx based on PTE

A-02	Interest Rate:	8.53%	
GE Model M3712R Turbine	Period (yrs):	25	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_x lb/hr:	46.00 lb/hr		<--Highest actual test data for GE M3712R-A plus 20% safety factor
NO_x tpy:	201.48 tpy		<-- Calculated using the highest actual test date plus 20% and 8760 operating hours.
SCR			
NO_x Reduction:	75.5%		<-- Reach the 50 ppmvd NOx limit
NO_x lb/hr:	11.25 lb/hr		<-- Based on highest test-result of GE M3712R-A at equivalent reduction to 50 ppmvd.
NO_x tpy:	49.28 tpy		<-- Expected annual NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$ -		<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$ 12,371,394		<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP) + $1 MM cost increase per vendor
Total Capital Investment	$ 12,371,394		
Annualized TCI:	$ 1,211,848		<-- Based on interest rate, year and TCI
Administrative Costs:	$ 3,370		<--Based on 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost)
Annual O&M Costs:	$ 473,790		<-- Annual Cost Estimate (A-02)
Total Annual Costs:	$ 1,689,008		
Emissions Reduction:	152.2 tpy		
Cost Effectiveness:	**$ 11,096.93**	**$/ton**	

Pecos River Unit A-02: Cost Estimate

Total Capital Investment (TCI) =	$ 12,371,394

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$473,790
Indirect Annual Costs (IDAC) =	$1,215,218
Total annual costs (TAC) = DAC + IDAC	$1,689,008

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI	$61,857	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	
Annual Reagent Cost =	Reagent Consumption Rate/Hour x Cost of R_{eagent} x Operating Hours/Year =	$218,124	Vendor quote - $2.49/gal of aqueous ammonia delivered to site; Per vendor 6/9/2022 email, at 100% full load, ammonia consumption rate is approximately 10 gph.
Annual Electricity Cost =	Electricity Consumption Rate x Cost of $E_{lectricity}$ x Operating Hours/Year =	$29,609	Vendor quote - 50 kW, Default rate of $0.0676/kWh and 8760 hrs used in the calculation
Annual Catalyst Replacement Cost =	Catalyst replacement cost $ x FWF =	$76,600	Catalyst replacement cost = $250,000 per vendor, FWF = 0.3064 based on 24,000 hr catalyst life and 8.53% interest rate.
Direct Annual Cost =		$473,790	

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,370
Capital Recovery Costs (CR)=	CRF x TCI =	$1,211,848
Indirect Annual Cost (IDAC) =	AC + CR =	$1,215,218

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,689,008 Per Year
NOx Removed =	152.2 tons/year
Cost Effectiveness =	$11,096.93

El Paso Natural Gas Company, LLC

Pecos River Compressor Station - 50 ppmv NOx based on PTE

Unit: A-03	Interest Rate:	8.53%	
GE Model M3712R Turbine	Period (yrs):	25	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_x lb/hr:		46.00 lb/hr	<--Highest actual test data for GE M3712R-A plus 20% safety factor
NO_x tpy:		201.48 tpy	<-- Calculated using the highest actual test date plus 20% and 8760 operating hours.
SCR			
NO_x Reduction:		75.5%	<-- Reach the 50 ppmvd NOx limit
NO_x lb/hr:		11.25 lb/hr	<-- Based on highest test result of GE M3712R-A at equivalent reduction to 5
NO_x tpy:		49.28 tpy	<-- Expected annual NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-	<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$	12,371,394	<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP+RWIP) + $1MM
Total Capital Investment	$	12,371,394	
Annualized TCI:	$	1,211,848	<-- Based on interest rate, year and TCI
Administrative Costs:	$	3,370	<--Based on 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost)
Annual O&M Costs:	$	473,790	<-- Annual Cost Estimate (A-03)
Total Annual Costs:	$	1,689,008	
Emissions Reduction:		152.2 tpy	
Cost Effectiveness:	**$**	**11,096.93**	**$/ton**

Pecos River Unit A-03: Cost Estimate

Total Capital Investment (TCI) =	$ 12,371,394

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$473,790
Indirect Annual Costs (IDAC) =	$1,215,218
Total annual costs (TAC) = DAC + IDAC	$1,689,008

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI	$61,857	
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	
Annual Reagent Cost =	Reagent Consumption Rate/Hour x Cost of R_{eagent} x Operating Hours/Year =	$218,124	Vendor quote - $2.49/gal of aqueous ammonia delivered to site; Per vendor 6/9/2022 email, at 100% full load, ammonia consumption rate is approximately 10 gph
Annual Electricity Cost =	Electricity Consumption Rate x Cost of $E_{lectricity}$ x Operating Hours/Year =	$29,609	Vendor quote - 50 kW, Default rate of $0.0676/kWh and 8760 hrs used in the calculation
Annual Catalyst Replacement Cost =	Catalyst replacement cost $ x FWF =	$76,600	Catalyst replacement cost = $250,000 per vendor, FWF = 0.3064 based on 24,000 hr catalyst life and 8.53% interest rate.
Direct Annual Cost =		$473,790	

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,370
Capital Recovery Costs (CR)=	CRF x TCI =	$1,211,848
Indirect Annual Cost (IDAC) =	AC + CR =	$1,215,218

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,689,008 Per YearP
NOx Removed =	152.2 tons/year
Cost Effectiveness =	$11,096.93

MEMORANDUM

ALL4

To:	El Paso Natural Gas Company, LLC	**Date:**	November 30, 2022
From:	ALL4 LLC		
Subject:	Independent 3rd Party Certification of Alternative Emissions Standards (AES) Proposal for Demontration of Compliance with Subsection B of 20.2.50.113 New Mexico Adminstrative Code		

Introduction

El Paso Natural Gas Company, LLC (EPNG, Company) owns and operates the following compressor stations in New Mexico:

- Afton Compressor Station, Doña Ana County
- Belen Compressor Station, Valencia County
- Caprock Compressor Station, Lea County
- Pecos River Compressor Station, Eddy County

There is at least one existing, stationary natural gas-fired combustion turbine greater than 1,000 horsepower (hp) at each facility that is subject to the emissions standards in Table 3 of Paragraph (7) of Subsection B of 20.2.50.113 New Mexico Administrative Code [Table 3 20.2.50.113.B(7) NMAC]. In lieu of meeting these emissions standards, 20.2.50.113.B(11) NMAC allows for the owner or operator to submit a request for Alternative Emissions Standards (AES) if compliance is technically impracticable or economically infeasible. EPNG has evaluated the turbines at the above referenced facilities and determined that they qualify for AES for compliance with the nitrogen oxide (NO_X) emissions standard in Table 3. Prior to submitting the AES, 20.2.50.113.B(11)(d) NMAC requires that the owner or operator contract with an independent third-party engineering or consulting firm to conduct a technical and regulatory review of the proposal. EPNG prepared the AES request and has contracted with ALL4 LLC (ALL4) to review the proposal. This submittal contains a summary of ALL4's review of the AES, including a certification that it is a complete submittal and adheres to all of the requirements of 20.2.50.113.B(11) NMAC.

AES Review and Certification

For an AES, the following requirements in 20.2.50.113.B(11)(a)-(c) NMAC must be met:

(a) Prepare a reasonable demonstration detailing why it is not technically practicable or economically feasible for the individual engine or turbine to achieve the emissions standards in table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC or table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC, as applicable;

As discussed in the introduction, the sources for which the AES are requested by EPNG are existing, stationary natural gas-fired combustion turbines and therefore are subject to the standards in Table 3 of 20.2.50.113.B(7) NMAC. Specifically, EPNG is requesting approval of AES from the NO_X standards in Table 3. The following control technology alternatives were evaluated to determine whether compliance with these emissions standards would be technically impracticable or economically infeasible:

- **Water or steam injection**
- **Lean pre-mix / Dry combustion controls**
- **Oxidation catalyst (EM_x / $SCONO_x$)**
- **Selective Catalytic Reduction (SCR)**
- **Selective Non-Catalytic Reduction (SNCR)**
- **Good combustion practices**

Section 3 of the AES introduces each alternative and provides technical information regarding how they function to reduce NO_X emissions. A discussion is included in the AES that explains the technical feasibility of each control technology alternative by providing a comparison of the operating conditions and technical specifications of each turbine against the minimum requirements needed for the alternative to properly function. Additionally, where possible, feedback from a representative of the turbine manufacturer was provided indicating whether a specific alternative would be feasible. The final list of technically feasible alternatives is limited to selective catalytic reduction (SCR) and good combustion practices. ALL4 agrees with the initial list of alternatives, the process for evaluating the technical feasibility of each option, and the final list of alternatives considered technically practicable.

SCR is the only remaining alternative where physical modifications are required for implementation. Therefore, EPNG prepared an additional analysis for each turbine to evaluate whether it would be an economically feasible approach to complying with the applicable NO_X emissions standard. The cost effectiveness was evaluated following the standard industry approach from United States Environmental Protection Agency's (U.S. EPA) Air Pollution Control Cost Manual. The procedures and equations from Section 4, Chapter 2 for Selective Catalytic Reduction were utilized.

To quantify an overall cost effectiveness, the total direct and indirect annual costs must be determined. For each turbine, the total capital investment (TCI) required to implement the alternative (SCR) was estimated. This TCI was annualized utilizing a capital recovery factor associated with EPNG's actual cost of borrowing interest rate and a 25-year lifespan of the equipment. The total indirect annual cost was calculated based on the sum of this capital recovery cost and an administrative charge associated with the

operator labor and maintenance costs per Section 2.4.2 of Chapter 2 of U.S. EPA's cost manual. The direct annual costs, including maintenance, labor, reagent, electricity, and catalyst replacement were estimated using a combination of vendor quotes, engineering estimates, and default values from the cost manual. The inputs to these calculations and the final results were verified by ALL4 to be reasonable and accurate.

In addition to both the indirect and direct annual costs, the anticipated NO_X removal in tons per year (tpy) is necessary to estimate the overall cost effectiveness. To quantify the NO_X removal, the difference in emissions between the current uncontrolled emissions rate and the emissions rate corresponding to the applicable standard from Table 3 of 20.2.50.113.B(7) NMAC was calculated. The current uncontrolled emissions rate was derived from the highest actual test data available to EPNG for a similar turbine with a 20% safety factor applied. The use of a larger current uncontrolled NO_X emissions rate results in a lower cost effectiveness value and a more conservative result from the analysis. Therefore, ALL4 supports the methodology used for estimating the emissions reduction that would be expected to occur as a result of complying with the applicable NO_X emissions standard. The inputs and the final results were verified to be reasonable and accurate.

Finally, the cost effectiveness is calculated by dividing the total direct and indirect annual costs by the estimated NO_X reduction. The calculations for each turbine are presented separately in the AES. ALL4 reviewed each calculation and the results were verified to be reasonable and accurate. For each turbine, the total cost effectiveness to comply with the standard was compared to a threshold of $7,500/ton. This comparison is located in Table 4-2 of the AES. The threshold is specifically referenced on Page 111 of the Statement of Reasons and Final Order for Title 20, Chapter 2, Part 50 by the State of New Mexico Environmental Improvement Board (EIB 21-27). Considering this cost effectiveness threshold was specifically referenced in the documents associated with the publication of the final rule, ALL4 agrees that it is reasonable to use them as a threshold for determining whether a specific control technology is economically feasible or not.

The results of the economic evaluation indicate that it would not be economically feasible to implement SCR for the turbines in the AES proposal. This leaves good combustion practices as the only remaining feasible option. Good combustion practices are already in use on these turbines. Therefore, this option cannot be used to reduce emissions further for compliance with the applicable NO_X emissions standards in Table 3 of 20.2.50.113.B(7) NMAC. Alternative emissions standards corresponding to the use of good combustion practices were developed which are lower than the turbines currently permitted NO_X emissions limits. EPNG has committed to the continued use of good combustion practices to ensure that the units operate with the lowest possible NO_X emissions. Turbine Inspection and Maintenance Schedules Best Practices procedures have been developed based on a recommendation from the manufacturer and EPNG has

systems in place to ensure that the turbines are operated and maintained in accordance with those procedures.

After reviewing all elements of the AES, ALL4 believes that the proposal reasonably demonstrates that it would not be technically practicable or economically feasible for each individual turbine to achieve the emissions standards in Table 3 20.2.50.113.B(7) NMAC. Therefore, the use of good combustion practices and the corresponding alternative emissions standards included in the proposal are appropriate for these turbines.

(b) Prepare a demonstration detailing why emissions from the individual engine or turbine cannot be addressed through an ACP in a technically practicable or economically feasible manner;

The Alternative Compliance Plan (ACP) is a compliance option specified in 20.2.50.113.B(10) where an owner or operator demonstrates that the total allowable

emissions for all engines or turbines will not exceed the total allowable emissions from those emissions units if they were complying with the applicable standard in 20.2.50.113.B. This allows owners and operators to reduce emissions across the entire company fleet, providing flexibility in the source of the reductions used to achieve compliance with the applicable emissions standards. The AES addresses the requirement in 20.2.50.113.B(11)(b) NMAC in Section 2.2, immediately following Table 2-1. Specifically, EPNG asserts that the ACP option is not technically or economically feasible due to these specific turbines accounting for over 50% of the total permitted NO_X emissions for the entire fleet and for the same reasons that it would not be technically or economically feasible to comply with the standard for each individual turbine. This assertion is valid as the list of technically feasible methods of controlling any one turbine does not change and the cost effectiveness for each turbine remains the same. Additionally, considering the proportion of EPNG's total NO_X emissions that are accounted for by these ten turbines, it is unlikely that reductions elsewhere would bring them all into compliance with the corresponding total allowable emissions rate allowed by the standards in Table 3. For these reasons, ALL4 agrees that an ACP would not be technically practicable or economically feasible and that the AES complies with the requirement in 20.2.50.113.B(11)(b).

(c) Prepare a technical analysis for the affected engine or turbine specifying the emission reductions that can be achieved through other means, such as combustion modifications or capacity limitations. The technical analysis shall include an analysis of any previous modifications of the source and a determination whether such modifications meet the definition of a reconstructed source, such that the source should be considered a new source under federal regulations. The analysis shall include a certification that the modifications to the source are not in violation of any state or federal air quality regulation; and

The AES addresses the requirement in 20.2.50.113.B(11)(c) NMAC in Section 2.2, immediately following Table 2-1. All potential physical modifications that would result in a reduction of NOx have been addressed in Sections 3 and 4 of the AES proposal, with information provided supporting whether they are technically practicable or not. Additionally, it is not possible to pursue capacity restrictions due to legal obligations of the Federal Energy Regulatory Commission (FERC), which requires the units remain active at all times so that they can provide a sufficient amount of horsepower for compression and transportation of natural gas to communities, public institutions, and businesses. Finally, there have been no modifications to the units that would meet the definition of reconstruction. For these reasons, ALL4 believes the AES Proposal sufficiently addresses the requirements in 20.2.50.113(B)(11)(c) NMAC.

(d) Fulfill the requirements of Subparagraphs (a) through (c) of Paragraph (10) of Subsection B of 20.2.50.113 NMAC. Paragraph 10

(a) *The owner or operator shall contract with an independent third-party engineering or consulting firm to conduct a technical and regulatory review of the ACP proposal. The selected firm shall review the proposal to determine if it meets the requirements of this Part, and shall prepare and certify an evaluation of the proposed ACP indicting whether the ACP proposal adheres to the requirements of this Part.*

(b) *Following the independent third-party review, the owner or operator shall provide the ACP, along with the third-party evaluation and findings, to the department for posting on the department's website. The department shall post the ACP and the third-party review within 15 days of receipt.*

(c) *Following posting by the department, the owner or operator shall publish a notice in a newspaper of general circulation announcing the ACP proposal, the dates it will be available for review and comment by the public, and information on how and where to submit comments. The dates specified in the public notice must provide for a thirty-day comment period.*

EPNG has contracted with ALL4 as an independent third-party engineering or consulting firm to conduct a technical and regulatory review of the AES Proposal. ALL4 has reviewed the AES request and has concluded that it is complete and meets all the requirements of 20.2.50.113.B(11) NMAC. This memorandum summarizes the review by ALL4 and why the AES proposal by EPNG is complete and sufficient.

Should you have any questions about this submittal, please feel free to contact Christopher Ward at 770.557.2798 or cward@all4inc.com.

Christopher M. Ward

Christopher M. Ward
Technical Manager
ALL4 LLC