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

April 12, 2023

FedEx Tracking No. 3966 7040 9359

Cindy Hollenberg, Chief
Compliance & Enforcement Section
NMED – Air Quality Bureau
525 Camino Del Los Marquez, Suite 1
Santa Fe, New Mexico 87505

Re: El Paso Natural Gas Company, L.L.C.'s Response to the New Mexico Environmental Department's Request for Additional Information Regarding the Alternative Emissions Standards Proposal Submitted Pursuant to 20.2.50.113.B.(11) NMAC

Dear Ms. Hollenberg:

On November 30, 2022, El Paso Natural Gas Company, L.L.C., a subsidiary of Kinder Morgan, Inc. (EPNG, or Kinder Morgan) submitted to the New Mexico Environment Department (NMED or "the Department") proposed Alternative Emissions Standards (AES) for 10 General Electric (GE) Frame 3 turbines at EPNG's four compressor stations that are subject to the newly adopted Ozone Precursor Rule codified at 20.2.50 NMAC. On December 20, 2022, EPNG received an email from NMED requesting additional information to continue evaluation of the AES. EPNG has also had several teleconferences with NMED since December 2022 to discuss the additional information requested. EPNG responds to NMED's specific questions in this letter. <u>In addition, concurrent with this response, EPNG is also re-submitting to NMED a revised AES that incorporates the additional information responsive to NMED's questions.</u>

In summary, the 10 GE turbines operated by EPNG qualify for an AES because the available control technologies that would be required to achieve the Ozone Precursor Rule NO_x limits are not cost effective, and the units cannot be addressed through an Alternative Compliance Plan (ACP). Notwithstanding, in the AES, EPNG proposes to take reductions of approximately 418 tons per year (tpy) of NO_x emissions across the units.

The following numbered items correspond to the items requested in your December 20, 2022 email. EPNG's response is provided immediately below each request for additional information.

1. **Please provide a <u>demonstration</u> that your fleet cannot meet the emissions standards through an Alternative Compliance Plan, as required by 20.2.50.113.B(11)(b) NMAC. Your proposal claims this, but the demonstration has not been made. This should include actual calculations that show, for example, why**

total allowable emissions for your fleet cannot meet the emission standards pursuant to 20.2.50.113.B(10) NMAC.

EPNG Response:

The Ozone Precursor Rule, at 20.2.50.113.B.(11) NMAC states that "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 rule further states that "[t]he 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." See 20.2.50.113.B.(11) NMAC (emphasis added). Subparagraph (b) of Paragraph (11) of Subsection B of 20.2.50.113 NMAC requires the owner or operator to "[p]repare 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." Thus, this demonstration does not require the submission of a comprehensive ACP, but does require a reasonable analysis showing that the target emissions standards for these individual turbines are not technically practicable or economically feasible, even through an ACP.

Regarding technical and economic feasibility, in particular, the New Mexico Environmental Improvement Board (EIB) adopted Paragraphs (10) and (11) of Subsection B of 20.2.50.113 NMAC "for the reasons stated in the NMED Rebuttal . . . and the supporting argument by Kinder Morgan, [Inc. (Kinder Morgan)]." State of New Mexico, Environmental Improvement Board, Statement of Reasons and Final Order, In the Matter of Proposed New Regulation 20.2.50 NMAC – Oil and Gas Sector – Ozone Precursor Pollutants, No. EIB 21-27, at pp. 111 (June 27, 2022) (hereinafter, Statement of Reasons). In particular, and citing to Kinder Morgan's supporting argument in the EIB rulemaking, the EIB states that "[w]hile the emissions thresholds provided in Tables 1 and 3 for existing engines and turbines are appropriate in most cases, circumstances may exist where it is technically impracticable or economically infeasible to achieve compliance." Id. Recognizing these practical limitations, the EIB's final rule "offers significant flexibility for sources that are unable to meet the emissions standards of Part 50: they may reduce the annual hours of operation, they may seek an [ACP] to meet an equivalent amount of emission reductions, and/or they may seek alternative emissions standards if they can demonstrate that they cannot meet the existing standards through an ACP." Id. (emphasis added). Thus, an operator may have in place both an AES (or multiple AESs for individual units), and an ACP. Further to costs, the EIB made clear that "[c]ost-effectiveness thresholds above which a certain control technology will be considered infeasible can vary, but, in general, the Department considers costs in excess of $7,500 per ton of pollutant reduced to be infeasible." Id.

As reflected in EPNG's November 30, 2022 submission, EPNG is requesting an AES for 10 GE gas turbines on the basis that achieving the Table 3 emission standards is not cost effective. The 10 GE gas turbines included in the AES proposal are subject to NO_x emission standard of 50 ppmvd @15% O_2 found in 20.2.50.113 NMAC. EPNG converted the emission standard to pounds per hour (pph) for each GE gas turbine included in the AES proposal. The allowable emission rates under the Ozone Precursor Rule are calculated by converting the pph emission rates to an annual basis assuming continuous operation (8,760 hr/yr). The required emission reductions are calculated as the difference between the current permit limits (tpy) and the allowable emission rates (tpy) under the Ozone Precursor Rule. The combined total permitted NO_x emissions for the 10 GE turbines are 2,082.4 tpy. The total allowable NO_x emissions under the Ozone Precursor Rule, 20.2.50.113.B. NMAC (Table 3), for the 10 GE turbines are 452 tpy by January 1, 2028. Consequently, the total required NO_x emission reduction for the 10 GE turbines is 1,630.4 tpy, to be incrementally achieved, by January 1, 2028. See 20.2.50.113.B.(7) NMAC. A detailed emissions summary for the 10 GE turbines is listed below in Table 1.

Table 1

Units	Permitted NO_x Emissions (TPY)	Rule Standard for NO_x (50 ppmvd@15% O_2) Converted to PPH	Rule Standard for NO_x Converted to TPY	NO_x Reduction Required by Ozone Precursor Rule (TPY)	AES Proposed NO_x Reduction (TPY)
Caprock A-1	201.0	12.3	53.9	147.1	20.5
Caprock A-2	172.1	7.7	33.7	138.4	80.5
Pecos River A-1	232.6	11.3	49.5	183.1	31.1
Pecos River A-2	232.6	11.3	49.5	183.1	31.1
Pecos River A-3	232.6	11.3	49.5	183.1	31.1
Afton A-1	224.5	11.3	49.5	175.0	23.0
Afton A-2	224.5	11.3	49.5	175.0	23.0
Afton A-3	224.5	11.3	49.5	175.0	23.0
Belen A-1	169.0	7.7	33.7	135.3	77.5
Belen A-2	169.0	7.7	33.7	135.3	77.5
Total	**2,082.4**		**452.0**	**1630.4**	**418.3**

Kinder Morgan is in the process of developing an ACP for the engines and turbines subject to the rule operated by Kinder Morgan or its affiliates and subsidiaries, including EPNG, TransColorado Gas Transmission Co., LLC, and Natural Gas Pipeline Company of America, LLC. The ACP will be submitted in accordance with 20.2.50.113(B)(10). The 10 GE turbines are excluded from the ACP for NO_x emissions because they cannot meet the emission standards through an ACP for the following reasons:

a. **Technology limits the available control options for the 10 GE turbines to Selective Catalytic Reduction.** As discussed during the rulemaking hearing, only one control option for GE Frame 3 turbines exists, and that is Selective Catalytic Reduction (SCR). The rulemaking record reflects that a water injection system is not available for GE Frame 3 turbines. See Exhibit A (Letter from Baker Hughes dated October 16, 2019). Baker Hughes stated in the October 16, 2019 letter that it does not have a water injection system or Dry Low NO_x (DLN) technology applicable to the GE Frame 3 A-F machines. Additionally, due to the age of GE Frame 3 turbines, Baker Hughes has not developed emissions abatement technology for the GE Frame 3 gas turbines to reduce NO_x emissions. As a result, SCR is the only technologically available control method to reduce NO_x emissions.

b. **Installing SCR on these 10 GE turbines is not cost effective.** Installing SCR on each of the 10 GE turbines is not cost-effective. The Department considers costs in excess of $7,500 per ton of pollutant reduced to be not cost effective. In the November 30, 2022 AES submitted to the Department, EPNG submitted cost-per-ton estimates that were based on the potential to emit (PTE) for each unit. Upon further review of the administrative record in support of the Ozone Precursor Rule, however, it is clear that cost-per-ton estimates should be based on actual emissions, rather than PTE. In particular, in its Statement of Reasons, the EIB details the cost estimates provided by Kinder Morgan in support of the EIB's adoption of Tables 1, 2, and 3, as well as the accompanying Provisions at Paragraphs (10) and (11) of Subsection B of 20.2.50.113 NMAC. See Statement of Reasons, at 100-01. Importantly, Kinder Morgan's cost-per-ton estimates were developed using actual emissions data, and not PTE.[1] This is because the units have historically not operated at their PTE, and a cost estimate considering PTE would not be reflective of the actual costs incurred to reduce emissions to the relevant regulatory threshold. Thus, in Table 2, below, EPNG provides the Department its updated analyses reflecting the cost-per-ton of reducing emission at each unit with the only available control technology – SCR – considering actual historic emissions as well as potential emissions. This approach is further consistent with the recommendation made by the Western Regional Air Partnership (WRAP) when conducting the four-factor analysis.[2] These data show that this path forward is, without a doubt, not cost effective.

[1] Notably, in the Department's rebuttal testimony (Ex. 1 in the rulemaking) the agency had raised questions with respect to how Kinder Morgan arrived at its cost-per-ton estimates, inquiring into the use of actual operating hours and actual emissions data. See NMED Ex. 1, at 46–48 (performing an estimation of cost effectiveness based on "full permitted capacity," i.e., PTE). In response, Kinder Morgan presented sur-rebuttal testimony on September 20, 2021 responsive to the Department's questions. In that sur-rebuttal testimony, Kinder Morgan presented additional cost-per-ton analyses using averaged operating costs over a 10-year period. The analysis demonstrated that the actual hours of operation/actual emissions were reasonably applied in the original analysis, and the cost-per-ton remained well above the reasonableness threshold of $7,500 per ton of NOx reduced. Based on this discussion and these findings, the Department presented, and the EIB approved, Paragraphs (10) and (11) of Subsection B of 20.2.50.113 NMAC to account for technical practicality and economic reasonableness, as required by statute. NMSA § 74-2-105(F) (requiring that the EIB "shall give weight it deems appropriate to . . . technical practicability and economic reasonableness of reducing or eliminating air contaminants . . .").

[2] *Supplementary Information for Four Factor Analyses by WRAP States*, Revised Draft Report (April 20, 2010); *see also* ADEQ Regional Haze State Implementation Plan 2028, Emissions Projection Methodology.

As demonstrated in EPNG's initial AES submittal of November 2022, even if the Department considers the overly conservative approach of using PTE to estimate the cost-per-ton, installation of SCR remains not cost effective.[3]

A summary of cost effectiveness ($/ton of pollutant reduced) based on both PTE and the average actual annual emissions from 2018 to 2020 is presented in Table 2 below.

Table 2

Units	Permitted Turbine Rating (hp)	Cost Effectiveness ($/ton NO_x Removed) Based on Actual Emissions*	Cost Effectiveness ($/ton NO_x Removed) Based on PTE
Afton A-1	6,150	$123,236	$11,697
Afton A-2	6,150	$458,302	$11,097
Afton A-3	6,150	$48,516	$11,097
Belen A-1	4,737	$88,704	$30,794
Belen A-2	4,737	$60,982	$29,214
Caprock A-1	6,026	$80,398	$9,933
Caprock A-2	4,879	$54,935	$29,283
Pecos River A-1	7,150	$27,877	$8,261
Pecos River A-2	7,150	$22,517	$11,097
Pecos River A-3	7,150	$26,527	$11,097

**KM Technical Testimony filed on July 28, 2021 before EIB in which KM used the average actual emissions from 2018 to 2020. The data in the third column of Table 2 were referenced by the EIB in support of adoption of Paragraphs (10) and (11) of Subsection B of 20.2.50.113 NMAC.*

c. **Including the 10 GE turbines in an ACP with the rest of Kinder Morgan's fleet is not possible.** As required under 20.2.50.113. B.(7), an ACP must include the list of

[3] As NMED reviews EPNG's cost-per-ton calculations, NMED may notice that the two sets of calculations apply different interest rates. For the PTE cost-per-ton calculations, EPNG applied a company-specific interest rate of 8.53% over the span the 25 year timeframe. The 8.53% is the actual interest rate that EPNG pays in the real world. Use of the 8.53% was recently approved in a Regional Haze process with the Arizona Department of Environmental Quality and the U.S. Environmental Protection Agency. In comparison, during the EIB Ozone Precursor rulemaking in 2021, Kinder Morgan submitted cost-per-ton calculations utilizing actual emissions data. In the actual cost-per-ton calculation, Kinder Morgan applied a *more conservative* interest rate of 3.25% over the span of the 20-year timeframe. EPA's cost analysis worksheet requests the user input the "current bank prime rate." At the time of the calculations, that prime rate was 3.25%, which again, is an EPA-approved methodology/value and is more conservative. For consistency with the rulemaking record, EPNG elected to use the actual cost-per-ton calculation submitted by Kinder Morgan during the rulemaking. However, it's worth noting that the current bank prime rate is closer to 8%, which is more in line with the EPNG company-specific interest rate. Calculations for each turbine are provided at Appendices [A-1] and [A-2] to the Revised AES Proposal submitted concurrently with this letter. Both sets of calculations use an EPA approved interest rate and both sets of calculations demonstrate that it is not cost-effective to control the GE turbines.

engines or turbines subject to the ACP, and a demonstration that the total allowable emissions for the engines or turbines subject to the ACP will not exceed the total allowable emissions under the emission standards of this Part. Total allowable NO_x emissions under the rule for the rest of Kinder Morgan's entire fleet consisting of seventeen (17) engines and nine (9) non-GE turbines (26 units in total), excluding the 10 GE turbines, is 1,064.6 tpy. If the 10 GE turbines in question were included in the ACP, the required reduction from the 10 GE turbines alone would be 1,630.4 tpy, an amount that exceeds the total allowable emissions from the 26 units that comprise the remainder of Kinder Morgan's fleet subject to the rule. Even if the 26 non-GE units were entirely shut down, Kinder Morgan could not achieve the required reductions while still operating the 10 GE turbines.

Furthermore, shutting down or reducing the capacity of the fleet of GE turbines, is not a feasible option at this time. The GE turbines, and in fact, the entire fleet of Kinder Morgan engines and turbines, are part of interstate natural gas pipelines that are subject to regulation by the Federal Energy Regulatory Commission (FERC) under the federal Natural Gas Act. See, e.g., 18 C.F.R. § 284.7(a) (setting forth requirements for interstate natural gas firm transportation service). FERC approves or "certificates" the pipeline to deliver natural gas. Kinder Morgan's entire pipeline system, as certificated by FERC, is based on the fact that Kinder Morgan can move gas 24 hours a day, 365 days a year at its designed capacity. Shutting down one or more of the company's turbines or engines would require that Kinder Morgan seek and obtain approval from FERC to abandon these units. In addition to being a lengthy administrative process, it is unlikely that FERC would approve shutting down the 10 GE turbines because it would diminish Kinder Morgan's ability to meet its obligations under the Natural Gas Act, drive up the cost of natural gas in the southwest United States, and deprive downstream consumers in New Mexico and other states of clean-burning natural gas to heat their homes and cook their food. Notably, multiple recent news articles and industry studies have discussed the relationship between market prices and pipeline capacity or deliverability. For example, an NGI article from January 20, 2023 discussed the high prices in New England caused by lack of adequate pipeline delivery capacity into the region.[4]

Additionally, market conditions support stable, if not increased, demand for natural gas. The Energy Information Administration's 2023 Annual Energy Outlook (AEO) analyzes long-term energy trends in the United States. In the context of the energy transition, while the AEO anticipates growth in renewable generating capacity, relative to 2022, the AEO projects that "natural gas generating capacity ranges from an increase of between 20% to 87% through 2050."[5] The AEO also concludes that "[d]espite the shift toward renewable sources and batteries in electricity generation,

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[4] Natural Gas Intelligence, "New England Gas Prices Soared in 2022 Amid Stiffer Global LNG Competition," (Jan. 20, 2023), *available at* https://www.naturalgasintel.com/haynesville-output-to-top-16-bcf-d-as-total-lower-48-production-continues-to-climb/.

[5] U.S. Energy Information Administration, Annual Energy Outlook 2023 (March 16, 2023) [hereinafter, AEO], *available at* https://www.eia.gov/outlooks/aeo/narrative/index.php ("Despite the growth in adopting heat pumps, natural gas-fired heating equipment, including furnaces and boilers, continue to account for the largest share of energy consumption for space heating in U.S. residential and commercial buildings across all cases through 2050.").

domestic natural gas consumption remains relatively stable, . . . [n]atural gas production . . . in some cases continues to grow in response to international demand for liquefied natural gas, supported by associated natural gas produced along with crude oil."[6]

In summary, at this time, shutting down or reducing capacity of the GE turbines as part of an ACP is not a viable solution.

d. **Replacement with electric drive motors is not required by rule, and is not cost effective.** The Department's evaluation of technical feasibility and cost-effective control measures has been limited to specific control technologies available for the existing units. This is an appropriate scope, and Kinder Morgan agrees that replacement of the 10 GE turbines with electric drive motors, for example, would be beyond the scope of the requirement of the rule and NMED's authority. In the context of existing sources in particular, the Department's purpose is to identify "control" opportunities. See NMSA 1978, Section 74-2-5(C) (providing the EIB authority to adopt a plan "to control emissions of oxides of nitrogen . . . .") (Emphasis added). The use of "control" here contemplates that emissions sources will install controls to reduce emissions—not eliminate or replace those emissions sources altogether. See West Virginia v. EPA, 142 S. Ct. 2587, 2612 n.3 (2022) ("Section 111(d) empowers EPA to guide States in establishing standards of performance for existing source, not to direct existing sources to effectively cease to exist.") (internal quotations and citations omitted). Cf. Sierra Club v. EPA, 499 F.3d 653, 657 (7th Cir. 2007) (not requiring a control technology that would "redefine the source" in the context of new source permitting).

Notwithstanding the limitations EPNG faces with respect to the 10 GE turbines, and to demonstrate its commitment to reasonable emissions reductions, **EPNG will reduce its permitted limits as part of the AES.** In particular, after a detailed review of testing conducted on the 10 GE Frame 3 turbines and similar turbines in Kinder Morgan's nationwide fleet, Kinder Morgan has identified achievable reductions in permitted NO_x emissions for these GE turbines. Thus, EPNG proposes 418.3 tpy of NO_x emissions reductions (see Table 1) from the current permitted allowable NO_x emissions for these GE Frame 3 turbines.

2. **The emission standards found in 20.2.50.113 NMAC are in units of ppmvd @15% O_2. To compare your proposed AES with what is in the rule, we need equivalent units. Please provide your proposed AES in these units, showing the calculations used to convert.**

EPNG Response:

The proposed AES for the 10 GE turbines are in pounds per hour (pph). Kinder Morgan has updated the Alternative Emission Standards in both pph and ppmvd. The equivalent units in ppmvd@15% O_2 are presented in Table 3.

[6] See AEO, at Figures 14 and 17.

In order to convert from pph to ppmvd @15% O_2, the following inputs are needed: %O_2, high heating value of natural gas, fuel specific F-Factor (dscf/mmBtu), conversion factor for NO_x from ppm to lb/dscf, and fuel flow of natural gas.

Sample calculation for Pecos River A-3 is demonstrated as follows:

Inputs: %O_2 measured during test = 18.92%
HHV of pipeline quality natural gas = 1,032 Btu/scf
Fuel specific F-Factor determined during test = 8,694 dscf/mmBtu
Conversion factor for NO_x = (ppm x 1.194E-07)
Fuel Flow measured in test = 59,867 scfh
Proposed AES NO_x emission rate = 46.0 lb/hr

lb/mmscf = 46.0 (lb/hr) x 1,000,000 (scf/1 mmscf) / 59,867 (scf/hr) = 768.04
lb/mmBtu = 768.04 (lb/mmscf) / 1,032 (Btu/scf) = 0.744
Concentration (lb/dscf) = 0.744 (lb/mmBtu) x ((20.9-%O_2)/20.9) / 8,694 (dscf/mmBtu) = 8.11E-06
Bias corrected concentration (ppm) = 8.11E-06 / (1,194E-07) = 67.9
Bias corrected concentration (ppmvd@15% O_2) = 67.9 x 5.9 / (20.9-% 02) = 202

Table 3

Units	KM Proposed AES for NO_x (pph)	KM Proposed AES for NO_x (ppmvd@15% O_2)	Rule Standard for NO_x (ppmvd@ 15% O_2)
Caprock A-1	41.2	169	50
Caprock A-2	20.9	131	50
Pecos River A-1	46.0	202	50
Pecos River A-2	46.0	202	50
Pecos River A-3	46.0	202	50
Afton A-1	46.0	202	50
Afton A-2	46.0	202	50
Afton A-3	46.0	202	50
Belen A-1	20.9	131	50
Belen A-2	20.9	131	50

Thank you for the opportunity to provide this supplemental response regarding EPNG's AES pursuant to 20.2.50.113.B.(11) NMAC. As demonstrated above and in the attached revised AES, the 10 GE turbines cannot be addressed through an ACP; however, Kinder Morgan is proposing reductions of allowable NO_x emissions of 418.3 tons per year. If you have any questions or need any additional information, please contact me at (303) 914-7616.

Sincerely,

Weiwen Daly
EHS Engineer
Air Permitting & Compliance – East
KM Natural Gas Pipelines

New Mexico Alternative Emission Standards Proposal

Prepared for
El Paso Natural Gas Company, LLC

November 2022

Revision April 2023

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1 Executive Summary

The New Mexico Environmental Department (NMED) proposed and the New Mexico Environmental Improvement Board (EIB) 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 engines or 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)., a subsidiary of Kinder Morgan, Inc. (Kinder Morgan), requests alternative emission standards for ten (10) GE stationary natural gas-fired combustion turbines on the basis of economic infeasibility.

EPNG conducted a technical and economic analysis of emission controls for the 10 GE stationary natural gas-fired combustion turbines to reduce NO_X emissions. The only technically practicable technology for each turbine is Selective Catalytic Reduction (SCR). In general, NMED considers costs in excess of $7,500/ton of pollutant reduced to be economically infeasible. As noted in Kinder Morgan's Technical Testimony filed on July 28, 2021, and further documented in this submission, the cost per ton of installing SCR on these 10 GE turbines ranges up to $458,302 based on actual historical operating hours. Even in the most conservative case, based on Potential to Emit (PTE), installing SCR on these 10 GE turbines is not economically feasible. A review of potential control technologies and cost analyses are presented in Sections 3 and 4. The economic infeasibility of SCR installation is summarized below in Table 1-1. EPNG has concluded that alternative emission standards (AES) for NOx for the 10 GE gas turbines are warranted because the cost of compliance for technically practicable retrofit emission control technologies is not economically feasible, and the units' NOx emissions cannot be addressed through an Alternate Compliance Plan (ACP).

Table 1-1 Summary of Cost Effectiveness Evaluation

Turbine Location	Unit No.	Permitted Turbine Rating (hp)	Cost Effectiveness ($/ton NOx Removed) Based on Actual Emissions*	Cost Effectiveness ($/ton NO_X Removed) Based on PTE
Afton	A-01	6,150	$123,236	$11,697
Afton	A-02	6,150	$458,302	$11,097
Afton	A-03	6,150	$48,516	$11,097
Belen	A-01	4,737	$88,704	$30,794
Belen	A-02	4,737	$60,982	$29,214
Caprock	A-01	6,026	$80,398	$9,933
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Pecos River	A-01	7,150	$27,877	$8,261
Pecos River	A-02	7,150	$22,517	$11,097
Pecos River	A-03	7,150	$26,527	$11,097

*The data in the second-to-last column are from Kinder Morgan's Technical Testimony filed on July 28, 2021 before the EIB in which KM used the average actual emissions from 2018 to 2020. This data was ultimately relied upon by the EIB in support of adoption of Paragraphs (10) and (11) of Subsection B of 20.2.50.113 NMAC, which are the options to comply with the emissions limits through an AES or ACP. See State of New Mexico, Environmental Improvement Board, Statement of Reasons and Final Order, In the Matter of Proposed New Regulation 20.2.50 NMAC – Oil and Gas Sector – Ozone Precursor Pollutants, No. EIB 21-27, at pp. 100-101 (June 27, 2022) (hereinafter, Statement of Reasons). The last column shows cost-ineffectiveness calculations based on the more conservative PTE scenario. Even if the Department considers the overly conservative approach of using PTE to estimate the cost-per-ton, installation of SCR remains economically infeasible. See Section 4, Cost Analysis, for additional discussion regarding the economic infeasibility evaluation.

2 Introduction

The regulatory background and turbine information are summarized below.

2.1 Regulatory Background

The New Mexico EIB finalized the Ozone Precursor rule under 20.2.50 NMAC to reduce ozone emissions at existing and new 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.

EPNG owns and operates 10 existing GE 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. These 10 GE turbines are included in this AES proposal.

Table 2-1 EPNG Sources Included in The AES

Engine Location	Unit No.	Turbine Manufacturer	Turbine Model	Hourly NOx Permit Limit	Annual NOx Permit Limit
Afton	A-01	GE	MS3712R-A	51.3 pph	224.5 tpy
Afton	A-02	GE	MS3712R-A	51.3 pph	224.5 tpy
Afton	A-03	GE	MS3712R-A	51.3 pph	224.5 tpy
Belen	A-01	GE	MS3572R-C	38.6 pph	169.0 tpy
Belen	A-02	GE	MS3572R-C	38.6 pph	169.0 tpy
Caprock	A-01	GE	MS3702R-C	45.9 pph	201.0 tpy
Caprock	A-02	GE	MS3572R-C	39.3 pph	172.1 tpy
Pecos River	A-01	GE	MS3712R-A	51.3 pph	232.6 tpy
Pecos River	A-02	GE	MS3712R-A	51.3 pph	232.6 tpy
Pecos River	A-03	GE	MS3712R-A	51.3 pph	232.6 tpy
Total					2,082.4 tpy

The Ozone Precursor Rule, at 20.2.50.113.B(11) NMAC states that "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 rule further states that "[t]he 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 emission 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." See 20.2.50.113.B.(11) NMAC (emphasis added). Subparagraph (b) of Paragraph (11) of Subsection B of 20.2.50.113 NMAC requires the owner or operator "[p]repare 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." Thus, this demonstration does not require the submission of a comprehensive ACP, but does require a *reasonable* (but not exhaustive) showing that the target emission standards for these individual turbines are not technically practicable or economically feasible, even through an ACP.

Regarding technical practicability and economic feasibility, in particular, the EIB adopted Paragraphs (10) and (11) of Subsection B of 20.2.50.113 NMAC "for the reasons stated in the NMED Rebuttal . . . and the supporting argument by Kinder Morgan." State of New Mexico, Environmental Improvement Board, Statement of Reasons and Final Order, In the Matter of Proposed New Regulation 20.2.50 NMAC – Oil and Gas Sector – Ozone Precursor Pollutants, No. EIB 21-27, at pp. 111 (June 27, 2022) (hereinafter, Statement of Reasons). In particular, and citing to Kinder Morgan's supporting argument in the EIB rulemaking, the EIB stated that "[w]hile the emissions thresholds provided in Tables 1 and 3 for existing engines and turbines are appropriate in most cases, circumstances may exist where it is technically impracticable or economically infeasible to achieve compliance." Id. at 111. Recognizing these practical limitations, the EIB's final rule "offers significant flexibility for sources that are unable to meet the emissions standards of Part 50: they may reduce the annual hours of operation, they may seek an Alternative Compliance Plan ACP to meet an equivalent amount of emission reductions, and/or they may seek alternative emissions standards if they can demonstrate that they cannot meet the existing standards through an ACP." Id. at 111 (emphasis added). Thus, an operator may have in place both an AES (or multiple AESs for individual units), and an ACP. Further to costs, the EIB made clear that "[c]ost-effectiveness thresholds above which a certain control technology will be considered infeasible can vary, but, in general, the Department considers costs in excess of $7,500 per ton of pollutant reduced to be infeasible." Id.

EPNG is requesting an AES for NOx for these 10 existing GE gas turbines on the basis that achieving the Table 3 emission standards found in 20.2.50.113 NMAC is economically infeasible. The 10 GE gas turbines subject to the AES proposal are subject to the NOx emission standard of 50 ppmvd @15% O_2. EPNG converted the emission standard to pounds per hour (pph) for each GE gas turbine subject to the AES proposal. The allowable annual emission rates under the Ozone Precursor rule are calculated by converting the pph emission rates to an annual basis assuming continuous operation (8,760 hr/yr). The required emission reductions are calculated as the difference between the current permit limits (tpy) and the allowable annual emission rates (tpy) under the Ozone Precursor rule. The combined total permitted NOx emissions for the 10 GE turbines is 2,082.4 tpy. The total allowable NOx emissions under the Ozone Precursor rule, 20.2.50.113.B NMAC (Table 3), for the 10 GE turbines is 452.0 tpy by January 1, 2028. Therefore, the total required NOx emission reductions for the 10 GE turbines is 1,630.4 tpy, to be incrementally achieved, by January 1, 2028. See 20.2.50.113.B.(7) NMAC. A summary of allowable emissions under the rule and the reductions proposed by the AES for the 10 GE turbines is listed below in Table 2-2.

Table 2-2 Allowable Emissions and Proposed Reductions for 10 GE Turbines

Units	Permitted NOx Emissions (tpy)	Allowable Hourly NOx Emissions (pph) (equivalent of 50 ppmvd @15% O_2)	Allowable Annual NOx Emissions Complying the Rule (tpy)	NOx Reduction Required by the Rule (tpy)	NOx Reduction Proposed by AES (tpy)
Afton A-1	224.5	11.3	49.5	175.0	23.0
Afton A-2	224.5	11.3	49.5	175.0	23.0
Afton A-3	224.5	11.3	49.5	175.0	23.0
Belen A-1	169.0	7.7	33.7	135.3	77.5
Belen A-2	169.0	7.7	33.7	135.3	77.5
Caprock A-1	201.0	12.3	53.9	147.1	20.5
Caprock A-2	172.1	7.7	33.7	138.4	80.5
Pecos River A-1	232.6	11.3	49.5	183.1	31.1
Pecos River A-2	232.6	11.3	49.5	183.1	31.1
Pecos River A-3	232.6	11.3	49.5	183.1	31.1
Total	**2,082.4**		**452.0**	**1,630.4**	**418.3**

Kinder Morgan is in the process of developing an Alternate Compliance Plan (ACP) for the engines and turbines subject to the rule operated by Kinder Morgan or its affiliates and subsidiaries, including EPNG, TransColorado Gas Transmission Co., LLC, and Natural Gas Pipeline Company of America, LLC. The ACP will be submitted in accordance with 20.2.50.113(B)(10). The 10 GE turbines are excluded from the ACP for NOx emissions because they cannot meet the emission standards through an ACP for the following reasons:

- Technology limits the available control options for the 10 GE turbines to Selective Catalytic Reduction (SCR). See Section 3 (Potential Control Technology Review).
- Installing SCR on the 10 GE turbines is not economically feasible. See Section 4 (Cost Analysis and Proposed Alternative Emissions Standards); see also Appendix A-1 (Control Cost Estimate Based on Potential to Emit for El Paso Natural Gas Company GE Turbines); Appendix [A-2] (Control Cost Estimate Based on Actual Emissions for El Paso Natural Gas Company GE Turbines).
- Including the 10 GE turbines in an ACP with the remainder of Kinder Morgan's fleet is not possible. See Section 5 (Exclusion from ACP).

Notwithstanding the lack of cost effective control strategies, the inability to address via an ACP, and the limitations on reducing hours of operations or capacity, Kinder Morgan has proposed reductions in permit allowable emission rates for NOx. Under the proposed AES, Kinder Morgan proposes to reduce 418.3 tons of NOx emission annually combined from the 10 GE gas turbines. See Section 6 (Proposed Alternative Emission 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.

Water or steam injection is not, however, available for all types of unit. The ten turbines included in this request are GE Frame 3 turbines. Based on feedback from GE representatives, water or steam injection technology is not available to the GE Frame 3 gas turbines. Accordingly, this NOx control method is not technically feasible. See Appendix A-3 (Letter from Baker Hughes dated October 16, 2019 and provided in the Ozone Precursor rulemaking as attachment T to Kinder Morgan's rebuttal technical testimony).

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, 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 10 GE turbines requiring AES 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, EM_X™/$SCONO_X$™ is not technically feasible for the control of NO_X emissions from the 10 GE 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:

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[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.

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

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 850°F. The exhaust temperatures of the turbines included in this evaluation are approximately 850-950°F, 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:

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

[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.

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 (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 Replacement with Electric Drive

In anticipation of potential comments, EPNG documents in this submission that replacement of these 10 turbines with electric motors is neither required by the applicable rule.

In particular, in the context of existing sources in particular, the Department's purpose is to identify "control" opportunities. See NMSA 1978, Section 74-2-5(C) (providing the EIB authority to adopt a plan "to control emissions of oxides of nitrogen . . . .") (emphasis added). The use of "control" here contemplates that emissions sources will install controls to reduce emissions—not eliminate or replace those emissions sources altogether. See West Virginia v. EPA, 142 S. Ct. 2587, 2612 n.3 (2022) ("Section 111(d) empowers EPA to guide States in establishing standards of performance for existing sources, not to direct existing sources to effectively cease to exist.") (internal quotations and citations omitted). Cf. Sierra Club v. EPA,499 F.3d 653, 657 (7th Cir. 2007) (not requiring a control technology that would "redefine the source" in the context of new source permitting).

3.1.7 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.

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

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 10 GE 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
3.1.7	Good Combustion Practices	Yes

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 and Appendix A-2.

Overall, economic feasibility 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 is 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. EPNG calculated cost-per-ton estimates based on actual historic emissions as well as potential emissions. As shown above and below, the economic feasibility values (under both scenarios displayed) are above $7,500 for all 10 GE turbine units.

4.1.1 Control Cost Effectiveness Evaluation

The details of the turbine control cost effectiveness evaluation based on potential emissions are included in Appendix A-1 and Appendix A-2. The findings of the economic analysis based on the average actual annual emissions from 2018 to 2020 and PTE are summarized in Table 4-1.

[8] Statement of Reasons, at 111 ("[I]n general, the Department considers costs in excess of $7,500 per ton of pollutant reduced to be in feasible.").

Regional Air Partnership (WRAP) when conducting the four-factor analysis for Regional Haze.[9] These data show that this path forward is, without a doubt, not cost-effective.

Finally, the last column shows cost-ineffectiveness calculations based on the more conservative PTE scenario.

As demonstrated by the data in Table 1-1 and the enclosed Appendices, even if the Department considers the overly conservative approach of using PTE to estimate the cost-per-ton, installation of SCR remains cost ineffective.

Based on the information provided in Table 4-1, the only available control technology for the 10 GE turbines, SCR, was considered to be economically infeasible.

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[9] Supplementary Information for Four Factor Analyses by WRAP States, Revised Draft Report (April 20, 2010); see also ADEQ Regional Haze State Implementation Plan 2028, Emissions Projection Methodology; 40 C.F.R. Part 51, Appendix Y (discussing in relevant part how to calculate baseline emissions for the purpose of cost-effectiveness analysis for Best Available Retrofit Technology, which should "represent a realistic depiction of the anticipated annual emissions for the source. . . . you will estimate the anticipated annual emissions based upon actual emissions from a baseline period.").

5 Exclusion from ACP is Appropriate

5.1 The 10 GE Turbines cannot be Incorporated into an ACP

As noted above, Subparagraph (b) of Paragraph (11) of Subsection B of 20.2.50.113 NMAC requires the owner or operator "[p]repare 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." This demonstration does not require the submission of a comprehensive ACP, but does require a reasonable analysis showing that the target emissions standards for these individual turbines are not technically practicable or economically feasible, even through an ACP. This Section 5 is responsive to this requirement.

An ACP must include the list of engines or turbines subject to the ACP, and a demonstration that the total allowable emissions for the engines or turbines subject to the ACP will not exceed the total allowable emissions under the emission standards of this Part. See 20.2.50.113. B.(7) NMAC. Kinder Morgan cannot satisfy this requirement if it includes the 10 GE turbines in the ACP. Total allowable NOx emissions under the rule for the rest of Kinder Morgan's entire fleet consisting of 17 engines and nine (9) non-GE turbines (26 units in total), excluding the 10 GE turbines, is 1,064.6 tpy. If the GE turbines in question were included in the ACP, the required reduction from the 10 GE turbines alone would be 1,630.4 tpy, an amount that exceeds the total allowable emissions from the 26 units that comprise the remainder of Kinder Morgan's fleet subject to the rule. Even if the 26 non-GE units were entirely shut down, Kinder Morgan could not achieve the required reductions while still operating the 10 GE turbines.

Furthermore, shutting down or reducing the capacity of the fleet of GE turbines, is not a feasible option at this time. The GE turbines, and in fact, the entire fleet of Kinder Morgan engines and turbines, are part of interstate natural gas pipelines that are subject to regulation by the Federal Energy Regulatory Commission (FERC) under the federal Natural Gas Act. See, e.g., 18 C.F.R. § 284.7(a) (setting forth requirements for interstate natural gas firm transportation service). FERC approves or "certificates" the pipeline to deliver natural gas. Kinder Morgan's entire pipeline system, as certificated by FERC, is based on the fact that Kinder Morgan can move gas 24 hours a day, 365 days a year at its designed capacity. Shutting down one or more of the company's turbines or engines would require that Kinder Morgan seek and obtain approval from FERC to abandon these units. In addition to being a lengthy administrative process, it is unlikely that FERC would approve shutting down the 10 GE turbines because it would diminish Kinder Morgan's ability to meet its obligations under the Natural Gas Act, drive up the cost of natural gas in the southwest United States, and deprive downstream consumers in New Mexico and other states of clean-burning natural gas to heat their homes and cook their food. Notably, multiple recent news articles and industry studies have discussed the relationship between market prices and pipeline capacity or deliverability. For example, an NGI article from January 20, 2023 discussed the high prices in New England caused by lack of adequate pipeline delivery capacity to into the region.[10]

Additionally, market conditions project stable, if not increased, demand for natural gas. The Energy Information Administration's 2023 Annual Energy Outlook (AEO) analyzes long-term energy trends in the United States. In the context of the energy transition, while the AEO anticipates growth in renewable generating capacity, relative to 2022, the AEO projects that "natural gas generating capacity ranges from an increase of between 20% to 87% through 2050."[11] The AEO also concludes that "[d]espite the shift toward renewable sources and batteries in electricity generation, domestic natural gas consumption remains relatively stable," however, "Natural gas production . . . in some cases continues to grow in response to international demand for liquefied natural gas, supported by associated natural gas produced along with crude oil."[12]

In summary, at this time, shutting down or reducing capacity of the GE turbines as part of an ACP is not a viable solution.

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[10] Natural Gas Intelligence, "New England Gas Prices Soared in 2022 Amid Stiffer Global LNG Competition," (Jan. 20, 2023), *available at* https://www.naturalgasintel.com/haynesville-output-to-top-16-bcf-d-as-total-lower-48-production-continues-to-climb/.

[11] U.S. Energy Information Administration, Annual Energy Outlook 2023 (March 16, 2023) [hereinafter, AEO], *available at* https://www.eia.gov/outlooks/aeo/narrative/index.php ("Despite the growth in adopting heat pumps, natural gas-fired heating equipment, including furnaces and boilers, continue to account for the largest share of energy consumption for space heating in U.S. residential and commercial buildings across all cases through 2050.").

[12] See AEO, at Figures 14 and 17.

6 EPNG's Proposed Alternative Emissions Standards

Notwithstanding the limitations EPNG faces with respect to the 10 GE turbines, and to demonstrate its commitment to reasonable emissions reductions, EPNG will reduce its permitted limits as part of the AES. In particular, after a detailed review of testing conducted on the 10 GE Frame 3 turbines and similar turbines in Kinder Morgan's nationwide fleet, Kinder Morgan has identified achievable reductions in permitted NOx emissions for these GE turbines. Thus, EPNG has proposed 418.3 tpy of NOx emissions reductions (see Table 2-2) from the current permitted allowable NOx emissions for these GE Frame 3 turbines.

6.1 Proposed Alternative Emission Standards

Under 20.2.50.113.B(11), the Ozone Precursor rule states an owner or operator may submit a request for AES 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, and make hours limitations impracticable.

Thus, to be conservative in establishing the AES, the operating hours were assumed to be 8,760 hours per year. In order to maintain an acceptable margin to compliance, EPNG calculated the AES using the highest 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. Specifically, the combined proposed annual NOx emissions from the 10 GE turbines show a reduction of 418.3 tons compared to the current permitted values. Kinder Morgan believes these reductions demonstrate a good faith effort to meet the requirements of the rule to the best of our ability given cost, technology, and national regulatory obligations.

EPNG is proposing to accept these AES as enforceable emission limitations. Because the emission standards found in 20.2.50.113 NMAC are in units of parts per million by volume (ppmvd), expressed on a dry basis at 15 percent oxygen (15% O_2), EPNG converted the AES in pph to ppmvd @15% O_2. The proposed AES for each turbine are presented in Table 6-1, and the reduction in emissions, as compared with annual permitted emissions, are shown in Table 6-2.

Table 6-1 Proposed Alternative Emissions Standards for NOx in pph and ppmvd@15% O_2

Turbine Location	Unit No.	Proposed Hourly NOx Emissions	Proposed Annual NO_x Emissions	Proposed NOx Limit (ppmvd@15% O2)
Afton	A-01	46.0 pph	201.5 tpy	202
Afton	A-02	46.0 pph	201.5 tpy	202
Afton	A-03	46.0 pph	201.5 tpy	202
Belen	A-01	20.9 pph	91.5 tpy	131
Belen	A-02	20.9 pph	91.5 tpy	131
Caprock	A-01	41.2 pph	180.5 tpy	169
Caprock	A-02	20.9 pph	91.6 tpy	131
Pecos River	A-01	46.0 pph	201.5 tpy	202
Pecos River	A-02	46.0 pph	201.5 tpy	202
Pecos River	A-03	46.0 pph	201.5 tpy	202
Total			1,664.1	

Table 6-2 Annual NOx Emissions Comparisons between Current Permit and Proposed AES

Turbine Location	Unit No.	Annual NOx Permit Limit (tpy)	Proposed Annual NOx Emissions (tpy)	NOx Reduction Proposed by AES (tpy)
Afton	A-01	224.5	201.5	23.0
Afton	A-02	224.5	201.5	23.0
Afton	A-03	224.5	201.5	23.0
Belen	A-01	169.0	91.5	77.5
Belen	A-02	169.0	91.5	77.5
Caprock	A-01	201.0	180.5	20.5
Caprock	A-02	172.1	91.6	80.5
Pecos River	A-01	232.6	201.5	31.1
Pecos River	A-02	232.6	201.5	31.1
Pecos River	A-03	232.6	201.5	31.1
Total		2,082.4	1,664.1	418.3

In order to convert from pph to ppmvd@15% O_2, the following inputs are needed: %O_2 measured in the test, high heating value (HHV) of natural gas, fuel specific EPA F-Factor (dscf/mmBtu), conversion factor for NOx from ppm to lb/dscf, and fuel flow of natural gas measured in the test (scfh). Because Pecos River A-03 had the highest hourly tested emission rate for GE model MS3712R-A, it is used in the sample calculation below to convert the hourly NOx emission rate to ppmvd@15% O_2.

Inputs: %O_2 measured during test = 18.92%
HHV of pipeline quality natural gas = 1,032 Btu/scf
Fuel specific EPA F-Factor determine during test = 8,694 dscf/mmBtu
Conversion factor for NOx = (ppm x 1.194E-07)
Fuel flow measured in test = 59,867 scfh
Proposed AES NOx hourly emission rate = 46.0 lb/hr

lb/mmscf = 46.0 (lb/hr) x 1,000,000 (scf/1 mmscf) / 59,867 (scf/hr) = 768.04
lb/mmBtu = 768.04 (lb/mmscf) / 1,032 (Btu/scf) = 0.744
Concentration (lb/dscf) = 0.744 (lb/mmBtu) x ((20.9-%O2)/20.9) / 8,694 (dscf/mmBtu) = 8.11E-06
Bias corrected concentration (ppm) = 8.11E-06 / (1,194E-07) = 67.9
Bias corrected concentration (ppmvd@15% O2) = 67.9 x 5.9 / (20.9-%O_2) = 202

Appendix A-1

Control Cost Estimate Based on Potential to Emit for El Paso Natural Gas Company GE 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_{eagent} 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 $E_{lectricity}$ 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,···.·· $/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) + $1MI
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

Appendix A-2

Control Cost Estimate Based on Actual Emissions for El Paso Natural Gas Company GE Turbines

El Paso Natural Gas Company, LLC

Afton Compressor Station - 50 ppmc NOx based on Last Emissions Test

GE Model M3712R Turbine	Interest Rate:	3.25%	<-- EPA Default Interest Rate
A-01	Period (yrs):	20	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_x lb/hr:		23.92 lb/hr	<-- July 29, 2020 portable analyzer stack test result (permit limit is 51.26 lb/hr)
NO_x tpy:		14.81 tpy	<-- Calculated 7/29/2020 stack test results and 2011 through 2020 avg actual operating hours.
SCR			
NO_x Reduction:		56.5%	<-- Reach the 50 ppmc Nox from 2020 emissions test
NO_x lb/hr:		10.40 lb/hr	<-- Based on reaching the 50 ppmc Nox limit (estimated from 1994 emission test)
NO_x tpy:		6.44 tpy	<-- Expected annually NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-	<-- Presumed to be included in CE2107005 shown below (Emission Controls CWIP)
SCR Capital Investment	$	12,258,524	<-- CE2107005 Caprock internal est 07/16/2021
Total Capital Investment	$	12,258,524	
Annualized TCI:	$	843,128	<-- Based on interest rate, year and TCI
Administrative Charge	$	3,364	
Annual O&M Costs:	$	185,066	<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	1,031,557	
Emissions Reduction:		8.4 tpy	
Cost Effectiveness:	**$**	**123,236.19 $/ton**	

El Paso Natural Gas Company, LLC

Afton Compressor Station - 50 ppmc NOx based on Last Emissions Test

GE Model M3712R Turbine	Interest Rate:	3.25%	
A-02	Period (yrs):	20	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_x lb/hr:		23.92 lb/hr	<-- July 29, 2020 portable analyzer stack test result (permit limit is 51.26 lb/hr)
NO_x tpy:		3.62 tpy	<-- Calculated 7/29/2020 stack test results and 2011 through 2020 avg actual operating hours.
SCR			
NO_x Reduction:		56.5%	<-- Reach the 50 ppmc Nox from 2020 emissions test
NO_x lb/hr:		10.40 lb/hr	<-- Based on reaching the 50 ppmc Nox limit (estimated from 1994 emission test)
NO_x tpy:		1.58 tpy	<-- Expected annually NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-	<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$	11,371,394	<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP)
Total Capital Investment	$	11,371,394	
Annualized TCI:	$	782,112	<-- Based on interest rate, year and TCI
Administrative Charge	$	3,310	
Annual O&M Costs:	$	153,309	<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	938,731	
Emissions Reduction:		2.0 tpy	
Cost Effectiveness:	$	**458,301.93 $/ton**	

El Paso Natural Gas Company, LLC

Afton Compressor Station - 50 ppmc NOx based on Last Emissions Test

GE Model M3712R Turbine	Interest Rate:	3.25%	
A-03	Period (yrs):	20	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_x lb/hr:		23.92 lb/hr	<-- July 29, 2020 portable analyzer stack test result (permit limit is 51.26 lb/hr)
NO_x tpy:		37.23 tpy	<-- Calculated 7/29/2020 stack test results and 2011 through 2020 avg actual operating hours.
SCR			
NO_x Reduction:		56.5%	<-- Reach the 50 ppmc Nox from 2020 emissions test
NO_x lb/hr:		10.40 lb/hr	<-- Based on reaching the 50 ppmc Nox limit (estimated from 1994 emission test)
NO_x tpy:		16.19 tpy	<-- Expected annually NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-	<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$	11,371,394	<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP)
Total Capital Investment	$	11,371,394	
Annualized TCI:	$	782,112	<-- Based on interest rate, year and TCI
Administrative Charge	$	3,310	
Annual O&M Costs:	$	235,383	<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	1,020,806	
Emissions Reduction:		21.0 tpy	
Cost Effectiveness:	**$**	**48,516.22 $/ton**	

El Paso Natural Gas Company, LLC

Belen Compressor Station - 50 ppmc NOx based on Last Emissions Test

GE Model M3712R Turbine	Interest Rate:	3.25%	<-- EPA Default Interest Rate
A-01	Period (yrs):	20	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_x lb/hr:		15.75 lb/hr	<-- March 30, 2021 portable analyzer stack test result (permit limit is 38.5 lb/hr)
NO_x tpy:		21.60 tpy	<-- Calculated 3/30/2021 stack test results and 2018 through 2020 avg actual operating hours.
SCR			
NO_x Reduction:		56.1%	<-- Reach the 50 ppmc Nox from 2021 emissions test
NO_x lb/hr:		6.91 lb/hr	<-- Based on reaching the 50 ppmc Nox limit (estimated from 1994 emission test)
NO_x tpy:		9.48 tpy	<-- Expected annually NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-	<-- Presumed to be included in CE2107005 shown below (Emission Controls CWIP)
SCR Capital Investment	$	12,258,524	<-- CE2107005 Caprock internal est 07/16/2021
Total Capital Investment	$	12,258,524	
Annualized TCI:	$	843,128	<-- Based on interest rate, year and TCI
Administrative Charge	$	3,364	
Annual O&M Costs:	$	229,030	<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	1,075,521	
Emissions Reduction:		12.1 tpy	
Cost Effectiveness:	$	**88,704.23 $/ton**	

El Paso Natural Gas Company, LLC

Belen Compressor Station - 50 ppmc NOx based on Last Emissions Test

GE Model M3712R Turbine	Interest Rate:	3.25%	
A-02	Period (yrs):	20	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_x lb/hr:		15.75 lb/hr	<-- March 30, 2021 portable analyzer stack test result (permit limit is 38.5 lb/hr)
NO_x tpy:		30.47 tpy	<-- Calculated 3/30/2021 stack test results and 2018 through 2020 avg actual operating hours.
SCR			
NO_x Reduction:		56%	<-- Reach the 50 ppmc Nox from 2021 emissions test
NO_x lb/hr:		6.91 lb/hr	<-- Based on reaching the 50 ppmc Nox limit (estimated from 1994 emission test)
NO_x tpy:		13.37 tpy	<-- Expected annually NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-	<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$	11,371,394	<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP)
Total Capital Investment	$	11,371,394	
Annualized TCI:	$	782,112	<-- Based on interest rate, year and TCI
Administrative Charge	$	3,310	
Annual O&M Costs:	$	257,491	<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	1,042,913	
Emissions Reduction:		17.1 tpy	
Cost Effectiveness:	**$**	**60,981.61 $/ton**	

El Paso Natural Gas Company, LLC

Caprock Compressor Station - 50 ppmc NOx limiting factor

GE Model M3712R Turbine	Interest Rate:	3.25%	<-- EPA Default Interest Rate
A-01	Period (yrs):	20	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_x lb/hr:		34.35 lb/hr	<-- Sept. 29, 2020 portable analyzer stack test result (permit limit is 45.9 lb/hr)
NO_x tpy:		11.51 tpy	
			<-- Calculated 9/29/2020 stack test results and 2018 through 2020 avg actual operating hours.
SCR			
NO_x Reduction:		66.2%	<-- Reach the 50 ppmc Nox limit
NO_x lb/hr:		11.62 lb/hr	<-- Based on reaching the 50 ppmc Nox limit (estimated from 1994 emission test)
NO_x tpy:		3.89 tpy	<-- Expected annually NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-	<-- Presumed to be included in CE2107005 shown below (Emission Controls CWIP)
SCR Capital Investment	$	7,180,921	<-- CE2107005 Caprock internal est 07/16/2021
Total Capital Investment	$	7,180,921	
Annualized TCI:	$	493,896	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	118,454	<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	612,350	
Emissions Reduction:		7.6 tpy	
Cost Effectiveness:	$	**80,398.40 $/ton**	

El Paso Natural Gas Company, LLC

Caprock Compressor Station - 50 ppmc NOx limiting factor

GE Model M3712R Turbine	Interest Rate:	3.25%	
A-02	Period (yrs):	20	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_x lb/hr:		16.83 lb/hr	<-- highest most recent test 9/29/2020 portable analyzer
NO_x tpy:		29.64 tpy	<-- Calculated using 2018 through 2020 average actual operating hours and 9/29/2020 results.
SCR			
NO_x Reduction:		56%	<-- Reach the 50 ppmc Nox limit
NO_x lb/hr:		7.38 lb/hr	<-- Based on reaching the 50 ppmc Nox limit (estimated from 1994 emission test)
NO_x tpy:		13.00 tpy	<-- Expected annually NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-	<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$	11,430,361	<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen R
Total Capital Investment	$	11,430,361	
Annualized TCI:	$	786,167	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	128,097	<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	914,265	
Emissions Reduction:		16.6 tpy	
Cost Effectiveness:	$	**54,935.11 $/ton**	

El Paso Natural Gas Company, LLC

Pecos River Compressor Station - 50 ppmc NOx based on Last Emissions Test

GE Model M3712R Turbine	Interest Rate:	3.25%	<-- EPA Default Interest Rate
A-01	Period (yrs):	20	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_x lb/hr:		23.46 lb/hr	<-- June 10, 2020 portable analyzer stack test result (permit limit is 53.1 lb/hr)
NO_x tpy:		49.90 tpy	<-- Calculated 6/10/2020 stack test results and 2018 through 2020 avg actual operating hours.
SCR			
NO_x Reduction:		53.5%	<-- Reach the 50 ppmc Nox from 2020 emissions test
NO_x lb/hr:		10.90 lb/hr	<-- Based on reaching the 50 ppmc Nox limit (estimated from 1994 emission test)
NO_x tpy:		23.18 tpy	<-- Expected annually NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-	<-- Presumed to be included in CE2107005 shown below (Emission Controls CWIP)
SCR Capital Investment	$	7,180,921	<-- CE2107005 Caprock internal est 07/16/2021
Total Capital Investment	$	7,180,921	
Annualized TCI:	$	493,896	<-- Based on interest rate, year and TCI
Administrative Charge	$	3,059	
Annual O&M Costs:	$	247,776	<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	744,730	
Emissions Reduction:		26.7 tpy	
Cost Effectiveness:	**$**	**27,877.28 $/ton**	

El Paso Natural Gas Company, LLC
Pecos River Compressor Station - 50 ppmc NOx based on Last Emissions Test

GE Model M3712R Turbine	Interest Rate:	3.25%	
A-02	Period (yrs):	20	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_x lb/hr:		27.34 lb/hr	<-- June 10, 2020 portable analyzer stack test result (permit limit is 53.1 lb/hr)
NO_x tpy:		81.55 tpy	<-- Calculated 6/10/2020 stack test results and 2018 through 2020 avg actual operating hours.
SCR			
NO_x Reduction:		60.1%	<-- Reach the 50 ppmc Nox from 2020 emissions test
NO_x lb/hr:		10.90 lb/hr	<-- Based on reaching the 50 ppmc Nox limit (estimated from 1994 emission test)
NO_x tpy:		32.51 tpy	<-- Expected annually NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-	<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$	11,371,394	<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP)
Total Capital Investment	$	11,371,394	
Annualized TCI:	$	782,112	<-- Based on interest rate, year and TCI
Administrative Charge	$	3,310	
Annual O&M Costs:	$	318,729	<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	1,104,151	
Emissions Reduction:		49.0 tpy	
Cost Effectiveness:	**$**	**22,516.97 $/ton**	

El Paso Natural Gas Company, LLC

Pecos River Compressor Station - 50 ppmc NOx based on Last Emissions Test

GE Model M3712R Turbine	Interest Rate:	3.25%	
A-03	Period (yrs):	20	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_x lb/hr:		27.39 lb/hr	<-- June 18, 2020 portable analyzer stack test result (permit limit is 53.1 lb/hr)
NO_x tpy:		67.20 tpy	<-- Calculated 6/18/2020 stack test results and 2018 through 2020 avg actual operating hours.
SCR			
NO_x Reduction:		60.2%	<-- Reach the 50 ppmc Nox from 2020 emissions test
NO_x lb/hr:		10.90 lb/hr	<-- Based on reaching the 50 ppmc Nox limit (estimated from 1994 emission test)
NO_x tpy:		26.74 tpy	<-- Expected annually NOx emisions (ton/yr) after SCR
Turbine Housing Reconfiguration	$	-	<-- Presumed to be included in CE2107005 shown below
SCR Capital Investment	$	11,371,394	<-- CE2107005 Caprock internal est 07/16/2021 (Emission CWIP+ Regen CWIP +Regen RWIP)
Total Capital Investment	$	11,371,394	
Annualized TCI:	$	782,112	<-- Based on interest rate, year and TCI
Administrative Charge	$	3,310	
Annual O&M Costs:	$	287,807	<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	1,073,229	
Emissions Reduction:		40.5 tpy	
Cost Effectiveness:	**$**	**26,526.85 $/ton**	

Appendix A-3

Baker Hughes Letter Dated October 16, 2019 and Provided in the Ozone Precursor Rulemaking as Attachment T to Kinder Morgan's Rebuttal Technical Testimony

T + 1 281-610-1164
11330 Clay Road
Houston, Texas 77041, USA

Baker Hughes

October 16, 2019

SUBJECT: FRAME 3 EMISSIONS TECHNOLOGY FOR AGED MODELS (FR3 A to G)

The first General Electric 2 shaft, Frame size 3 gas turbines were introduced in 1951. The first-generation models were Frame 3 A to G which were manufactured from 1951 to 1966. Emissions abatement technology was not developed for the Frame 3 gas turbines until the 1970's.

Baker Hughes currently does not have an any NOx abatement systems applicable to the Frame 3 A - F machines. Only a preliminary study was performed several years ago on the Frame 3F for LHE liner, no material was manufactured or supplied. We do not have water injection or DLN for the 32F.

There are currently no plans to develop NOx abatement technology for this model machine. It would take significant resources for such a study to take place.

PECOS RIVER 1	Gas turbine unit serial number 95025
PECOS RIVER 2	Gas turbine unit serial number 95053
PECOS RIVER 3	Gas turbine unit serial number 95055

Regards,

Tom Hadden
Senior Sales Manager
Turbomachinery & Process Solutions
Baker Hughes
11330 Clay Road | Houston, TX 77041, USA