2021 Regional Haze Four Factor Initial Control Determination

Facility: El Paso Natural Gas Willcox Compressor Station

Air Quality Division
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1.1 ADEQ Initial Control Determination for EPNG Willcox Compressor Station

ADEQ's initial determination is to find that it is reasonable not to require additional controls on El Paso Natural Gas (EPNG) Willcox Compressor Station during this planning period.

1.2 ADEQ Control Determination Finalization Timeline

In order to meet the State rulemaking process timeframe for proposed rule inclusion in the July 31st, 2021 Regional Haze state implementation plan (SIP) submittal, ADEQ must finalize all four factor analyses as expeditiously as possible. To provide an opportunity for interested stakeholders to review and comment on ADEQ's initial decision prior to finalization, the department intends to post initial decisions on the agency webpage along with the original source submitted four factor analyses. Once ADEQ has reviewed relevant stakeholder comments, the agency will revise its initial decisions if necessary and post final decisions (see Figure 1). ADEQ welcomes feedback on these initial decisions and invites any interested party to send their comments by **December 31st, 2020** to:

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Please note that this review and feedback opportunity does not constitute an official state implementation plan or state rulemaking comment period. The agency intends to provide an official 30 day comment period on any proposed SIP or rulemaking action in accordance with Arizona Revised Statutes §§ 41-1023, 49-425, and 49-444.

Figure 1: Four Factor Control Determination Process Map

2 ADEQ Four Factor Analysis

2.1 Summary

Willcox Compressor Station is a natural gas compressor station facility operated by El Paso Natural Gas (EPNG). The facility provides natural gas compression to EPNG's pipeline network. Willcox Compressor Station was identified by the ADEQ as one of the sources subject to the requirements to develop a four factor analysis. The ADEQ reviewed EPNG's analysis and agree with the conclusions. EPNG's report and their results are used as the basis for this report and the ADEQ's determinations. Some assumptions included in EPNG's original report were updated to provide more accurate cost estimates and/or better align with EPA guidance. Those changes are reflected in the information provided in this document.

EPNG proposed the following combustion control techniques for the two turbines at the Willcox Compressor Station that are subject to the Four Factor Analysis: Water or Steam Injection; Combustion Liner Upgrade with Low NOX Burner Design; and Good Combustion Practices. EPNG's proposed NOX post-combustion controls for the two subject turbines include: EMX™/SCONOX™ Technology; Selective Catalytic Reduction (SCR); and Selective Non-Catalytic Reduction (SNCR). The ADEQ agrees with the proposed control options and did not encounter any control options that were missing from EPNG's consideration.

EPNG evaluated the technical feasibility of the proposed combustion control techniques and the post-combustion controls in their four factor analysis. Based on EPNG's analysis, the ADEQ determined the following options to be technically feasible: Combustion Liner Upgrade with Low NOX Burner Design (DLN) and Selective Catalytic Reduction (SCR). However, based on EPNG's cost analysis, the ADEQ determined that neither the Combustion Liner Upgrade with Low NOX Burner Design (DLN) nor Selective Catalytic Reduction (SCR) to be cost effective options. The ADEQ proposes that EPNG continue to implement Good Combustion Practices to ensure that the subject turbines will be operated with the lowest NOx emissions. Thus, no emission limits are proposed as a result of this analysis.

2.2 Facility Overview

2.2.1 Process Description

Willcox Compressor Station is a natural gas compressor station facility located on Arzberger Road six miles east of Kansas Settlement Road, in Cochise County, Arizona.

At the Willcox Compressor Station, compression is accomplished using two compressors driven by natural gas-fired turbines. In addition, an emergency generator is maintained on site for use during power outages. Turbine operation is dictated by the amount of natural gas required to meet customer demand.

In addition, the facility is permitted to install and operate a turbine and emergency generator, referred to as the “Dragoon Compressor Station”. This equipment will be dedicated to mainline compression on the existing transmission pipelines.

Turbine-1 and Turbine-2 are the primary sources of air emissions at the Willcox Compressor Station. The facility has a potential to emit greater than the major source threshold of nitrogen oxides (NOX).

Table 1 – Current Emission Limits

Process/Emission Source	Pollutant	Emission Limit (Unit)
TURBINE-1	NO_X	68 lb/hr
TURBINE-2	NO_X	68 lb/hr

2.2.2 Baseline Emission Calculations

The baseline emissions calculations for the Willcox Compressor Station were based off of values submitted to the ADEQ from the 2016, 2017, and 2018 emission inventory submittals and are summarized in Table 2. These values were used in the ADEQ’s 2028 emission projection methodology.

Table 2 – Historical Emissions

Year	Process Throughput MMCF/yr Natural Gas	NO_X (tpy)	SO_2 (tpy)	PM (tpy)
2016	569.18	291.47	1.00	1.94
2017	635.37	282.53	1.11	2.16
2018	645.81	317.24	1.13	2.20

2.3 ADEQ Screening Methodology

The screening methodology adopted by the ADEQ is outlined in the document "ADEQ 2021 Regional Haze State Implementation Plan Source Screening Methodology". The ADEQ relied upon guidance from the Western Regional Air Partnership (WRAP) regarding the use of a "Q/d > 10" threshold to screen out sources from the four-factor analysis. To accomplish this, the ADEQ reviewed calendar year 2014 emission inventory data for sources of PM10, NOX, and SO2.

To determine the "Q" value, the facility-wide PM10 primary, nitrogen oxide, and sulfur dioxide annual emissions were totaled. Since Willcox Compressor station had a "Q" value greater than 10, it was isolated by the ADEQ.

To determine the "d" value, the ADEQ used GIS to plot the location of the Willcox Compressor Station and the boundary of all Class I areas within Arizona and surrounding States. Then, the distance (the "d" value) from the Willcox Compressor Station to the nearest Class I area boundary (in kilometers) was determined.

Once "Q" and "d" had been established, "Q/d" for Willcox Compressor Station was determined to be 12. These results are summarized in **Error! Reference source not found.**Table 3 below.

Table 3 – Four Factor Analysis Screening Values

Facility	Q (tpy)	d (km)	Q/D	Nearest CIA
El Paso Natural Gas – Willcox Compressor Station	321	27	12	Chiricahua WA

Generally, any processes that were identified as being effectively controlled were removed from consideration for the current implementation period. Because Willcox Compressor Station did not have any emission controls at the time of analysis, all of the processes were considered. Processes evaluated for four factor analyses included those which contribute to the top 80% of NOx, PM10, and SO2 summed facility-wide 2018 emissions.

Table 4 –Equipment Status

EMISSION UNIT	Status
CATERPILLAR GEN	Screened Out
DRAGOON A-01 **	Screened Out

DRAGOON A-AUX-01 **	Screened Out
TURBINE-1	Top 80%
TURBINE-2	Top 80%

The top 80% of emissions at Willcox Compressor Station during 2018 were determined to be emitted by the natural gas-fired combustion turbines, TURBINE-1 and TURBINE-2. The CATERPILLAR GEN, DRAGOON A-01, and DRAGOON A-AUX-01 were screened out for this process. Therefore, the Four Factor Analysis was conducted for TURBINE-1 and TURBINE-2.

2.4 Proposed Control Methodology

2.4.1 Baseline Control Scenario (Projected 2028 Emissions Profile)

The ADEQ's 2028 projection methodology relied on the emissions inventory data submitted to ADEQ via the State and Local Emissions Inventory System (SLEIS). For the 2028 emissions projections, the projection methodology used emissions data and throughput data. Since quality assured emissions data was not available, emissions data from 2015 – 2017 was used with the throughput data from 2016 – 2018. The projected air pollutants included PM_{10}, $PM_{2.5}$, SO_2, NO_X, CO, NH_3 and VOCs.

Emission units, unit processes, process throughputs (inputs or outputs), and emissions for pollutants were reviewed for Willcox Compressor Station.

For each pollutant, a scaling factor was determined by dividing the annual emissions from each emission unit by the annual throughput (operating hours). Then the average scaling factor over the three-year period (2015-2017) was calculated. In addition, the average process throughput for the three-year period (2016-2018) was calculated. The projected annual emissions for each unit process was determined by multiplying the average scaling factor (2015-2017) by the average process throughput (2016-2018).

The projected 2028 NO_X emissions for Willcox Compressor Station are presented in Table 5**Error! Reference source not found.** below.

Table 5 – Projected NO_X Emissions for 2028*

EMISSION UNIT	NO_X (tons)
CATERPILLAR GEN	0.09
DRAGOON A-01 **	25.34
DRAGOON A-AUX-01 **	1.22

TURBINE-1	134.72
TURBINE-2	157.44

* PM_{10} and SO_2 emissions were additionally considered for controls; however, all process emissions for these pollutants were de minimis and, thus, are not presented here.

** The Dragoon Compressor Station had not commenced construction at the time of this analysis. Its projected emissions are based on the permitted potential to emit calculations.

2.5 Evaluated Controls and Emission Estimates

In their submitted four factor analysis, EPNG evaluated combustion control options for the two turbines. It should be noted that combustion control basically reduces the peak flame temperature which thereby minimizes thermal NO_X formation. One such combustion control technique incorporates fuel and/or air staging. Another combustion control technique introduces inert substances. And in some cases, both methods are used in combination as a combustion control technique.

In addition to combustion control techniques, EPNG also evaluated several post-combustion control technologies for the turbines. While combustion techniques minimize the amount of NO_X created, post-combustion technologies reduces the amount of NO_X emitted to the atmosphere. This is accomplished by chemically reducing NO_X to elemental nitrogen (N_2) with or without the use of a catalyst (Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR), respectively).

To identify all possible control technologies for the turbines, EPNG reviewed the RACT/BACT/LAER Clearinghouse (RBLC) database in addition to technical literature. EPNG used both principles of control technology and engineering experience to identify the following NO_X control technologies for the turbines.

Combustion Control Options:

Water or Steam Injection

Lean Head End Combustion Liner Upgrade with Dry Low-NO_X

Good Combustion Practices

Post-Combustion Control Options:

EM_X/SCONO Technology

Selective Catalytic Reduction (SCR)

Selective Non-Catalytic Reduction (SNCR)

Each control technology and its feasibility are described in detail below.

2.5.1 Water or Steam Injection[1]

Description:

Water or steam injection is a control method that reduces the formation of thermal NO_X. Water or steam is injected into the flame area of the gas turbine combustor which provides a heat sink that thereby lowers the flame temperature. The lower the flame temperature, the lower the formation of thermal NO_X.

Availability:

TURBINE-1 and TURBINE-2 at the Willcox Compressor Station are General Electric (GE) Frame 3 turbines. According to EPNG's engineering team based on information provided by the vendor in a January 28, 2020 email, water and steam injection is not available for Frame 3 turbines. Thus, water and steam injection is not an option for either TURBINE-1 or TURBINE-2 at the Willcox Compressor Station.

Effectiveness:

Since neither water nor steam injection are technically feasible control technologies for the Willcox Compressor Station turbines, the potential control efficiency was not determined.

2.5.2 Lean Head End Combustion Liner Upgrade with Dry Low-NO_X[2]

Description:

The combustion process of the turbine is surrounded by a liner that allows air to flow into the combustion zone (the enclosed space where there combustion process takes place). The liner's purpose is to reduce the temperature of the combustor walls through convective cooling. However, the life of the liner is limited due to it being subject to the high temperatures of the combustion process. A common retrofit is to replace the old combustion liner with a new, upgraded liner. Case studies have found that first generation liners failed after an average of 5,000 hours, while newer third generation liners had the capacity to operate properly for over 10,000 hours.

Dry low-NOx (DLN) combustion technology is a pollution prevention technology that inhibits the conversion of atmospheric nitrogen to NOx 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.

To produce a lean fuel/air mixture, excess air is introduced into the combustion zone of the lean combustion system. The addition of the excess air leads to a reduction of the overall flame temperature. This occurs because a fraction of the energy released from combusting the fuel is

[1] Clean Air Technology Center, *Nitrogen Oxides (NO_X), Why and How They Are Controlled.* November 1999, p. 16

[2] Northeast States for Coordinated Air Use Management, *Status Report on NO_X for Industrial Boilers, Gas Turbines, Internal Combustion Engines, and Cement Kiln; Control Technologies & Cost Effectiveness*. December 2000, p. II-12 – II-14

instead diverted into heating the excess air to the reaction temperature. By pre-mixing the fuel and air prior to introduction into the combustion zone, a more uniform fuel/air mixture is provided. Pre-mixing also prevents localized high temperature regions within the combustor area.

EPNG's engineering team proposes implementing both of these controls simultaneously because both retrofits could be accomplished during the same major overhaul of the turbines. As a result, the installation costs would be optimized. For the purpose of this analysis, the Lean Head End Combustion liner upgrade in combination with DLN combustors were analyzed as one control technology.

Availability:

Both the liner upgrade and the DLN control technology are available options for the GE Frame 3 gas turbines.

Effectiveness:

Implementing Lean Head End Combustion Liner Upgrade with Dry Low-NO_X has the potential to reduce NO_X by 69% for TURBINE-1 and 70% for TURBINE-2.

2.5.3 Good Combustion Practices

Description:

Willcox Compressor Station currently employs good combustion practices for TURBINE-1 and TURBINE-2 to minimize NO_X emissions. By maintaining good combustion practices, the units operate as intended and produce low NO_X emissions. These practices were developed by EPNG following concepts from engineering knowledge, experience, and manufacturer's recommendations. These practices are maintained through training maintenance personnel, conducting routine inspections, conducting overhauls as appropriate for equipment involved, and using pipeline quality natural gas.

Since these practices are currently in place, they are used as the base case for this analysis. There is no additional change in emissions, since these practices are currently being used.

Availability:

Based on manufacturer recommendations, EPNG has developed Turbine Inspection and Maintenance Schedules Best Practices procedures. EPNG has systems in place to ensure that its turbines are operated and maintained in accordance with these procedures.

2.5.4 Oxidation Catalyst - EM_X/$SCONO_X$ Technology[3]

Description:

[3] NESCAUM, *Status Report on NO_X*, p. II-20

EM_X (the second-generation of the $SCONO_X$ NO_X Absorber Technology) is a control technology that utilizes a coated oxidation catalyst to remove NO_X and CO without a reagent. The $SCONO_X$ system is comprised of a platinum-based catalyst coated with potassium carbonate sorbent. The system is designed to be installed in the flue gas with a temperature range between 300°F to 700°F. The NO_X is oxidized by the catalyst and the resulting NO_2 is adsorbed into the sorbent. The sorbent must be regenerated periodically with hydrogen (H_2).

Availability:

EM_X/$SCONO_X$ control technology is available for TURBINE-1 and TURBINE-2.

Effectiveness:

Since the EM_X™/$SCONO_X$™ catalyst system was determined not to be a technically feasible control technology for Willcox Compressor Station, the potential control efficiency was not determined.

2.5.5 Selective Catalytic Reduction – SCR[4]

Description:

Selective catalytic reduction (SCR) is a post-combustion control technology that reduces nitric oxide (NO) emissions through injection of urea or ammonia (NH_3) into the flue gas. In this gas treatment process, ammonia reacts with NO on the catalyst surface to produce nitrogen gas (N_2) and water vapor. SCR is a control technology that is effective in reducing thermal and fuel NO_X emissions. It applies to all gas turbine types.

Variable loads can occur at compressor stations due to changes in weather and customer demands. These variable loads pose operational issues that can affect the effectiveness of SCR as a control option. For optimum NO_X reduction, the molar ratio of NH_3/NO_X must be maintained at a 1:1 ratio. If the molar ratio is not carefully controlled, this can result in lowered control efficiency and thus nonreacted NH_3 being emitted to the atmosphere (known as ammonia slip).

Availability:

SCR is applicable to all gas turbine types and thus is an available control system.

Effectiveness:

The removal efficiency for SCR was determined to be 70% for both TURBINE-1 and TURBINE-2, per EPA's Air Pollution Control Technology Fact Sheet for SCR.

Major Assumptions for Calculations:

[4] U.S. Environmental Protection Agency. *EPA Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines.* EPA-453/R-93-007, January 1993, p. 6-236

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) and is dependent on the material of the catalyst.

Since fluctuations in exhaust gas temperature reduce removal efficiency slightly by disturbing the NH_3/NO_X molar ratio, it is assumed that exhaust temperature would be constant. This assumption is based on an average of EPNG's 2016, 2017, and 2018 emissions test summaries.

2.5.6 Selective Non-Catalytic Reduction – SNCR[5]

Description:

Selective noncatalytic reduction (SNCR) is a post-combustion control technology that reduces NO_X emissions through injection of urea or ammonia into the flue gas. This add-on technology is similar to SCR; however the reduction of NO_X by urea or ammonia to nitrogen and water occurs without the use of a catalyst. This occurs because SNCR operates at a significantly higher temperature range of approximately 1,600 to 2,000°F. Operation of SNCR below this temperature range will result in ammonia slip.

Availability:

SNCR control technology is available for TURBINE-1 and TURBINE-2.

Effectiveness:

Since SNCR was determined not to be a technically feasible control technology for Willcox Compressor, the potential control efficiency was not determined.

Table 6 – Evaluated Controls

Control Option	Technically Feasible (Y/N)	Pollutant Impacted	Control Effectiveness (%)
Water or Steam Injection	No	NO_X	N/A
Lean Head End Combustion Liner Upgrade + Dry Low-NO_X	Yes	NO_X	69 – 70%
Good Combustion Practices	Yes	NO_X	Base Case
Oxidation Catalyst - EM_X/$SCONO_X$ Technology	No	NO_X	N/A

[5] U.S. EPA, *EPA Alternative Control Techniques*, p. 5-190 – 5-191

Selective Catalytic Reduction - SCR	Yes	NO_X	70%
Selective Non-Catalytic Reduction - SNCR	No	NO_X	N/A

2.6 Four Factor Analysis Review

EPNG evaluated the technical feasibility of the proposed controls in their four factor analysis. Based on their analysis, the ADEQ determined whether the proposed controls were feasible.

2.6.1 Technical Feasibility

2.6.1.1 Water or Steam Injection

TURBINE-1 and TURBINE-2 at Willcox Compressor Station are General Electric (GE) Frame 3 turbines. According to the El Paso Natural Gas engineering team, based on information provided by the vendor in a January 28, 2020 email, this technology is not available for Frame 3 turbines. Thus, the ADEQ has determined that water or steam injection is not a technically feasible NO_X control method for Willcox Compressor Station.

2.6.1.2 Lean Head End Combustion Liner Upgrade + Dry Low-NO_X

Replacing the combustion liner with an upgraded liner model is technically feasible since liners are designed to be replaced due to limited lifespan.

To implement the DLN controls, the gas turbine will require conversion from regenerative cycle to simple cycle. In addition, the combustion chamber will be reconfigured to allow for lean premixing or fuel staging. The ADEQ has determined that this is technically feasible for TURBINE-1 and TURBINE-2 at Willcox Compressor Station.

To optimize installation cost, both controls would be implemented simultaneously, thus they are treated as one control in this report.

2.6.1.3 Good Combustion Practices

This control technology was identified in EPNG's review of the RACT/BACT/LAER Clearinghouse (RBLC) for the control of NO_X emissions from combustion turbines. These practices are currently in place at Willcox Compressor Station.

2.6.1.4 Oxidation Catalyst - EM_X/$SCONO_X$ Technology

Both TURBINE-1 and TURBINE-2 at the Willcox Compressor Station have an exhaust temperature of approximately 800°F. The EM_X™/$SCONO_X$™ catalyst system is designed to operate effectively within a temperature range of 300 to 700°F, which is significantly below the turbine exhaust temperature at Willcox Compressor station. Thus, the ADEQ has determined that EM_X/$SCONO_X$ Technology is not a technically feasible control option.

2.6.1.5 Selective Catalytic Reduction – SCR

An important factor to the performance of SCR is the operating temperature. The operating range for a typical SCR installation is between 450 to 850 ºF. The exhaust temperature of both TURBINE-1 and TURBINE-2 at Willcox Compressor Station is approximately 800°F, within the operating range. Therefore, the ADEQ has determined that SCR is a technically feasible control technology for the turbines.

2.6.1.6 Selective Non-Catalytic Reduction – SNCR

An important factor to the performance of SNCR is the operating temperature. The temperature range required for a typical SNCR installation is between 1,600 to 2,000°F. The exhaust temperature of both TURBINE-1 and TURBINE-2 at Willcox Compressor Station is approximately 800°F, significantly below the desired operating range. Therefore, ADEQ has determined that SNCR is not a technically feasible control technology for the turbines.

Table 7 – Summary of Control Feasibility

NO_X Control		TURBINE-1	TURBINE-2
Combustion Control	Water or Steam Injection	Not Feasible	Not Feasible
	Lean Head End Combustion Liner Upgrade + Dry Low-NO_X	Feasible	Feasible
	Good Combustion Practices	Feasible	Feasible
Post-Combustion Control	Oxidation Catalyst - EM_X/$SCONO_X$ Technology	Not Feasible	Not Feasible
	Selective Catalytic Reduction - SCR	Feasible	Feasible
	Selective Non-Catalytic Reduction - SNCR	Not Feasible	Not Feasible

2.6.2 Cost of Compliance

The cost of each control technology was estimated using published methods, vendor quotes, and turbine characteristics. The initial capital cost was annualized over a 15-year period (per ADEQ guidance for the equipment life of turbine from time of installation) and added to the annual operating costs. An interest rate of 8.53% was used in the calculations. ADEQ found this to be an appropriate source specific interest rate after reviewing documentation provided by EPNG.

2.6.2.1 Lean Head End Combustion Liner Upgrade with Dry Low-NO_X

The Capital Cost for the DNL Conversion (52C+Simple Cycle Conversion + MKVIe Control System) was obtained from a vendor quote.

Equipment Cost was determined using the direct installation cost, indirect installation cost, and the contingency cost. The costs were estimated using EPA's "Alternative Control Techniques Document - NO_X Emissions from Stationary Turbines 1993", pages 6-220. Based on this methodology, the direct installation costs equals 45% of the total control systems cost plus taxes and freight. However, the direct installation cost was reduced from 45% to 15% due to the Original Equipment Manufacturer (OEM) installation being included in the quote. Based on EPA methods, the indirect installation costs were determined to be 20% of the total systems, taxes and freight, direct installation costs plus $5,000 for model plants with an output less than 5 MW. The contingency cost was estimated at 20% of the systems, taxes and freight, and direct and indirect installation costs using EPA methods.

Administrative costs, insurance, and taxes were estimated to be 4% of the total capital cost per EPA Air Pollution Control Cost Manual, 7th Ed., 2017.

Added maintenance costs for DLN were adjusted from the 1993 value per "Onsite Sycom Energy Corporation, Cost Analysis of NO_X Control Alternatives for Stationary Gas Turbines (1999)" to 2018 dollars using the Chemical Engineering Plant Cost Index.

The fuel penalty for the increased fuel consumption when converting to simple-cycle was obtained from a vendor quote.

The uncontrolled NO_X concentration was determined by using the average of the 2016, 2017, and 2018 Emissions Test Summaries. The controlled NO_X concentration was obtained from an email to GE (January 28, 2020). These values were used in determining the total annualized cost for TURBINE-1 and TURBINE-2.

The total annualized cost for TURBINE-1 was estimated at $1.28 million to remove 93 tpy of NO_X. This equates to a cost effectiveness of $13,847 per ton of NO_X removed. The post-control emission rate was estimated at 298 lb NO_X/MMCF.

The total annualized cost for TURBINE-2 was estimated at $1.34 million to remove 110 tpy of NO_X. This equates to a cost effectiveness of $12,212 per ton of NO_X removed. The post-control emission rate was estimated at 286 lb NO_X/MMCF.

2.6.2.2 Selective Catalytic Reduction – SCR

The cost data for this control option was obtained from vendor quotes from 2011 to 2013; then the values were adjusted from the 2012 dollar value.

The turbine exhaust parameters that were used in the reactor design, were obtained from the averages of the 2016, 2017, and 2018 Emissions Test Summaries. The chemical properties and constants used in the calculations were obtained from 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction. The density for the 19% ammonia was obtained from CF Industries Aqua Ammonia 19% Safety Data Sheet. The SCR design data was obtained from 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.5.

Direct costs were calculated using equations from the 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction and 2019 EPA Cost Manual, Chapter 2 Selective Catalytic

Reduction. In addition to the annual reference method test, indirect costs were calculated using 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction and 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction.

Total capital cost and the direct annual costs were estimated using 2002 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction. The Indirect annual costs and the cost effectiveness were estimated calculated using the 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction

The total annualized cost for TURBINE-1 was estimated to be $1,017,753 to remove 112 tpy of NO_X. This equates to a cost effectiveness of $9,086 per ton of NO_X removed. The post-control emission rate was estimated at 294 lb NO_X/MMCF.

The total annualized cost for TURBINE-2 was estimated to be $1,065,587 to remove 122 tpy of NO_X. This equates to a cost effectiveness of $8,770 per ton of NO_X removed. The post-control emission rate was estimated at 290 lb NO_X/MMCF.

The building that houses the turbines may have to undergo drastic modifications to accommodate a SCR system. Although this expense was not included in the cost analysis, the cost to modify the current building design could surpass millions of dollars.

Table 8 – Summary of Cost of Controls

NO_X Control	TURBINE-1 ($/ton)	TURBINE-2 ($/ton)
Lean Head End Combustion Liner Upgrade + Dry Low-NO_X	13,847	12,212
Selective Catalytic Reduction - SCR	9,086	8,770
Good Combustion Practices	0	0

Table 9 – Control Option Cost Effectiveness

Control Option	Unit	Capital Cost	Annualized Capital Cost	Total Annual Cost ($/yr)	Emission Reduction (tpy)	Cost-Effectiveness ($/ton)
Lean Head End Combustion Liner Upgrade with Dry Low-NO_X	TURBINE-1	$5,058,030	$610,188	$1,284,482	92.76	$13,847
	TURBINE-2	$5,058,030	$610,188	$1,338,793	109.63	$12,212

Selective Catalytic Reduction - SCR	TURBINE-1	$1,997,631	$240,989	$1,017,753	112	$9,086
	TURBINE-2	$1,983,910	$239,334	$1,065,587	122	$8,770

2.6.3 Time Necessary for Compliance

2.6.3.1 Lean Head End Combustion Liner Upgrade with Dry Low-NO_X

For each turbine, the time estimated to install the DLN control technology with liner upgrade is 14 months. This was the estimation provided from the EPNG Engineering Department. The 14 months include the time necessary for engineering, permitting, and installing the control technology.

2.6.3.2 Selective Catalytic Reduction – SCR

For each turbine, the time estimated to install the SCR system is 14 months. EPNG estimated this time using vendor quotes. The 14 months include the time necessary for engineering, permitting, and installing the control technology.

2.6.4 Energy and Non-Air Quality Impacts

2.6.4.1 Lean Head End Combustion Liner Upgrade with Dry Low-NO_X

The implementation of a liner upgrade with DLN will cause an increase in fuel usage.

Before the DLN control technology can be implemented, the GE gas turbines will first need to be converted from regenerative-cycle to simple-cycle. In doing so, this conversion will result in a reduction of the heat rate. Similarly, the liner upgrade will also result in a reduction of heat rate. Reducing the heat rate of the turbines will result in an increase of fuel usage for the turbines.

Based on a vendor quote, fuel usage is expected to increase by 40%. This increased fuel usage will lead to an increase in CO, VOC, and SO_2 formations.

2.6.4.2 Selective Catalytic Reduction – SCR

Implementation of SCR will require a system for ammonia storage, handling, and delivery. Such system would include vaporizers and blowers used to prepare the ammonia reagent for injection. Storage, transportation, and handling of ammonia results in health concerns since it increases risk of human exposure. Ammonia is listed as a hazardous substance under Title III Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). In addition to the risks associated with the storage, handling, and delivery of ammonia, spent catalyst is classified as a hazardous waste. Finally, increased ammonia emissions through ammonia slip can also act in combination with SO_2 or NO_x to produce the visibility impairing pollutants ammonium sulfate and ammonium nitrate, respectively.

The addition of an SCR system results in an increase of engine backpressure which has adverse impact on turbine efficiency.

The building that houses the turbines may have to undergo drastic modifications to accommodate a SCR system. Although this expense was not included in the cost analysis, the cost to modify the current building design could surpass millions of dollars.

2.6.5 Remaining Useful Life of Source

EPNG estimates that the earliest date in which the controls can be installed is 2025. Based on this assumption, the remaining useful life of each turbine is estimated to be 15 years (after 2025) for either control. The choice of control technology does not affect the remaining useful life of the GE gas turbines.