Arizona Department of Environmental Quality

2021 Regional Haze Four Factor Initial Control Determination

Facility: El Paso Natural Gas Williams Compressor Station

Air Quality Division
November 23, 2020

Table of Contents

List of Figures

List of Tables

1 ADEQ Initial Regional Haze Four Factor Control Determination

1.1 ADEQ Initial Control Determination for EPNG Williams

ADEQ's initial decision is to find that it is reasonable to require additional controls on EPNG Williams during this planning period in order to make reasonable progress toward natural visibility conditions. ADEQ proposes that EPNG continue to implement Good Combustion Practices for the subject turbine (TURBINE-1) and Low-emission Combustion (LEC 2) Retrofit for the three reciprocating engines (RECIP-1, RECIP-2, RECIP-5).

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 31, 2020** to:

Ryan Templeton, P.E.
Senior Environmental Engineer
Templeton.Ryan@azdeq.gov

Elias Toon, E.P.I.
Environmental Science Specialist
Toon.elias@azdeq.gov

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

Williams 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. Williams Compressor Station was identified by the ADEQ as one of the sources subject to the requirements to develop a four factor analysis. EPNG's report and 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.

El Paso Natural Gas (EPNG) conducted a step-wise review of NO_X control options for both the GE gas turbine and the reciprocating engines located at the Williams Compressor Station.

2.1.1 Potential Control Options

For the General Electric Gas Turbine (TURBINE-1), EPNG considered NO_X combustion control techniques as well as NO_X post-combustion control techniques. For the Clark reciprocating engines (RECIP-1, RECIP-2, and RECIP-5) EPNG considered NO_X combustion control, NO_X post-combustion control, and ultimately replacing the three reciprocating engines (process equipment) with low or no NO_X emitting equipment. The ADEQ agrees with the proposed control options and did not encounter any control options that were missing from EPNG's consideration. EPNG and ADEQ consider the following as potential control options for the Regional Haze subject equipment.

Table 1: Proposed Control Options

TURBINE-1	Combustion Control Options	Water or Steam Injection
		Combustion Liner Upgrade with Low NO_X Burner Design
		Good Combustion Practices
	Post Combustion Control Options	Selective Catalytic Reduction (SCR)
		EM_X™/$SCONO_X$™ Technology

		Selective Non-Catalytic Reduction (SNCR).
RECIP-1	Combustion Control Options	Air-Fuel Ratio Adjustment with High Energy Ignition
		Low-Emission Combustion (LEC) Retrofit
		Good Combustion Practices
	Post Combustion Control Options	Selective Catalytic Reduction (SCR)
RECIP-2	Combustion Control Options	Air-Fuel Ratio Adjustment with High Energy Ignition
		Low-Emission Combustion (LEC) Retrofit
		Good Combustion Practices
	Post Combustion Control Options	Selective Catalytic Reduction (SCR)
RECIP-5	Combustion Control Options	Air-Fuel Ratio Adjustment with High Energy Ignition
		Low-Emission Combustion (LEC) Retrofit
		Good Combustion Practices
	Post Combustion Control Options	Selective Catalytic Reduction (SCR)
PROCESS EQUIPMENT REPLACEMENTS		Replacing RECIP-1, RECIP-2, and RECIP-5 with one low NO_X Turbine

	Replacing RECIP-1, RECIP-2, and RECIP-5 with three electric engines

2.1.2 Technically Feasible Options

From the list of potential control options above, EPNG evaluated their technical feasibility. Based on EPNG's analysis, the ADEQ determined the following options to be technically feasible:

Table 2: Technically Feasible Options

TURBINE-1	Water or Steam Injection
	Combustion Liner Upgrade with Low NO_X Burner Design
	Selective Catalytic Reduction (SCR)
	Good Combustion Practices
RECIP-1	Selective Catalytic Reduction (SCR)
	Air-Fuel Ratio Adjustment with High Energy Ignition
	Low-Emission Combustion (LEC 1-3) Retrofit
	Good Combustion Practices
RECIP-2	Selective Catalytic Reduction (SCR)
	Low-Emission Combustion (LEC 1-3) Retrofit
	Good Combustion Practices
RECIP-5	Selective Catalytic Reduction (SCR)
	Low-Emission Combustion (LEC1-3) Retrofit

	Good Combustion Practices
PROCESS EQUIPMENT REPLACEMENTS	Replacing RECIP-1, RECIP-2, and RECIP-5 with one low NO_X Turbine
	Replacing RECIP-1, RECIP-2, and RECIP-5 with three electric engines

2.1.3 Economic Feasibility

From the list of technically feasible options above, the ADEQ determined the following options to be economically feasible:

Table 3: Economically Feasible Options

TURBINE-1	Good Combustion Practices
RECIP-1	Air-Fuel Ratio Adjustment with High Energy Ignition
	Low-emission Combustion (LEC 1) Retrofit
	Low-emission Combustion (LEC 2) Retrofit
	Good Combustion Practices
RECIP-2	Low-emission Combustion (LEC 1) Retrofit
	Low-emission Combustion (LEC 2) Retrofit
	Good Combustion Practices
RECIP-5	Low-emission Combustion (LEC 2) Retrofit
	Low-emission Combustion (LEC 3) Retrofit
	Good Combustion Practices

PROCESS EQUIPMENT REPLACEMENTS	Replacing RECIP-1, RECIP-2, and RECIP-5 with one low NO_X Turbine

Multiple options were considered to be economically feasible for the three reciprocating engines. The options were compared by taking into account the emissions reduction, total cost difference of the controls, and the consistency between controls and operations for the facility. Based on these factors the ADEQ determined that LEC 2 was the most reasonable control option.

Implementing LEC 2 would result in significant emission reductions, without overly burdensome capital and annual costs.

2.1.4 Proposed Emission Limits

Based on the technical and economic feasibility, the ADEQ proposes that EPNG continue to implement Good Combustion Practices for the subject turbine and Low-emission Combustion (LEC 2) Retrofit for the three reciprocating engines. The proposed emission limits for this recommendation are displayed in Table 4.

Table 4: Proposed Emission Limits

Unit / Process	Pollutant	Limit	Measure	Corresponding Control Technology
TURBINE-1	NO_X	$STD = 0.0150\frac{(14.4)}{Y} + F$	ppmvd @ 15% O_2, ISO	Good Combustion Practice
RECIP-1	NO_X	3.0	g/hp-hr	Low-emission Combustion (LEC 2) Retrofit
RECIP-2	NO_X	3.0	g/hp-hr	Low-emission Combustion (LEC 2) Retrofit
RECIP-5	NO_X	3.0	g/hp-hr	Low-emission Combustion (LEC 2) Retrofit

2.2 Facility Overview

EPNG Williams Compressor Station is located in Coconino County, about 3 miles north of exit 171 off I-40. The nearest Class I area to the station is the Sycamore Canyon Wilderness, located 29 km away from the station. ADEQ calculated the "Q/d" for this source to be 40.

2.2.1 Process Description

Williams Compressor Station provides natural gas compression to EPNG's pipeline network. Compression is accomplished by five (5) natural gas fired reciprocating engines and one (1) natural gas fired turbine that drive the compressor units. A Solar electric generator set provides the majority of the electric power to the site. In addition, an emergency generator is maintained on site for use during power outages.

Three Clark Reciprocating Engines (RECIP-1, RECIP-2, and RECIP-5) and Turbine-1 are the primary sources of air emissions at the Williams Compressor Station. The facility has a potential to emit greater than the major source threshold of nitrogen oxides (NO_X). There is no air pollution control equipment installed on the turbines or engines at the Williams Compressor Station.

Table 5 provides a list of all equipment at the Williams Compressor Station that is subject to the four-factor analysis as determined by the "Top 80% of Processes" conducted by ADEQ.

NO_X is the only pollutant subject to evaluation in this four-factor analysis.

Table 5: Current Emission Limits

Process/Emission Source	Pollutant	Emission Limit (ppmvd @ 15% O_2, ISO)
TURBINE-1	NO_X	$STD = 0.0150\frac{(14.4)}{Y} + F$
RECIP-1	NO_X	N/A
RECIP-2	NO_X	N/A
RECIP-5	NO_X	N/A

Permit No. 77575 does not impose a NO_X emission limit for RECIP-1, RECIP-2, or RECIP-5.

However, the permit does impose an emission limit for TURBINE-1, which is expressed as the following equation:

$$STD = 0.0150\frac{(14.4)}{Y} + F$$

where:

STD = allowable NO_X emissions (percent by volume at 15 percent oxygen and on a dry basis)

Y = Manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NO_X emission allowance for fuel-bound nitrogen as defined in 40 CFR 60.332(a)(4).

During the most recent performance test, conducted on June 12, 2019, the average limit was 194 ppmvd @ 15% O2, ISO. The test was performed at an average of 100% load.

2.2.2 Baseline Emission Calculations

The baseline emissions calculations for Williams 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 6. These values were used in the ADEQ's 2028 emission projection methodology.

Table 6: Historical Emissions

Year	Process Throughput (MMCF/yr Natural Gas)	NO_X (tpy)	SO_2 (tpy)	PM (tpy)
2016	1452.16	1117.41	2.03	12.59
2017	1110.28	902.28	1.60	8.97
2018	972.57	774.36	1.26	9.93

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 PM_{10}, NO_X, and SO_2.

To determine the "Q" value, the facility-wide PM_{10} primary, nitrogen oxide, and sulfur dioxide annual emissions were totaled. Since Williams 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 Williams Compressor Station and the boundary of all Class I areas within Arizona and surrounding States. Then, the distance (the "d" value) from the Williams Compressor Station to the nearest Class I area boundary (in kilometers) was determined.

Once "Q" and "d" had been established, "Q/d" for Williams Compressor Station was determined to be 40. These results are summarized in Table 7 below.

Table 7: Four Factor Analysis Screening Values

Facility	Q (tpy)	d (km)	Q/D	Nearest CIA
El Paso Natural Gas – Williams Compressor Station	786	19	40	Sycamore Canyon WA

The ADEQ applied a screening process to determine which emission units would undergo four factor analysis. The screening methodology adopted is outlined in the document "ADEQ 2021 Regional Haze State Implementation Plan Source Screening Methodology". Generally, any processes that were identified as being effectively controlled were removed from consideration for the current implementation period. Because Williams 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, PM_{10}, and SO_2 summed facility-wide 2018 emissions. Based on these criteria, the equipment not subject to the four-factor analysis is summarized in Table 8 and the equipment subject to the four-factor analysis is summarized in Table 9.

Table 8: Equipment Not Subject to Regional Haze Round 2

EQUIPMENT TYPE	MAX. CAPACITY	MAKE	EQUIPMENT ID NUMBER
Reciprocating Engine	2,000 hp	Clark	B-3

Reciprocating Engine	2,000 hp	Clark	B-4
Emergency Generator	530 hp	Ingersoll-Rand	AUX-1
Gas Turbine Engine Generator	837 hp	Solar	AUX-2

Table 9: Equipment Subject to Regional Haze Round 2

EQUIPMENT TYPE	MAX. CAPACITY	MAKE	EQUIPMENT ID NUMBER
Gas Turbine Engine	22,150 hp	General Electric	TURBINE-1
Reciprocating Engine	2,000 hp	Clark	RECIP-1
Reciprocating Engine	2,000 hp	Clark	RECIP-2
Reciprocating Engine	3,400 hp	Clark	RECIP-5

2.4 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 from 2015 – 2017 and 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 the Williams 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).

Table 10: Projected NO_X Emissions for 2028

EQUIPMENT TYPE	MAX. CAPACITY	MAKE	EQUIPMENT ID NUMBER	PROJECTED 2028 EMISSIONS NO_X (tons)
Emergency Generator	530 hp	Ingersoll-Rand	AUX-1	0.48
Gas Turbine Engine Generator	837 hp	Solar	AUX-2	6.35
Reciprocating Engine	2,000 hp	Clark	B-4	106.23
Reciprocating Engine	2,000 hp	Clark	B-3	133.53
Reciprocating Engine	2,000 hp	Clark	RECIP-1	148.4
Reciprocating Engine	2,000 hp	Clark	RECIP-2	170.4
Reciprocating Engine	3,400 hp	Clark	RECIP-5	205.16
Gas Turbine Engine	22,150 hp	General Electric	TURBINE-1	290.42

2.5 General Electric Turbine

2.5.1 Proposed Control Methodology

2.5.1.1 Evaluated Control and Emission Estimates

In order to identify all control technologies for the equipment subject to the 4FA, EPNG reviewed the RACT/BACT/LAER Clearinghouse (RBLC) database as well as technical literature. In their analysis, EPNG included combustion and post combustion options for the turbine; controls and retrofits for the reciprocating engines; replacing the reciprocating engines with a low NO_X emitting turbine; as well as replacing the reciprocating engines with three electric engines. ADEQ's research of the RBLC database did not identify any additional control options.

NO_X reduction can be accomplished by two general methodologies: combustion control techniques and post-combustion control methods. Combustion control techniques incorporate fuel or air staging that affect the kinetics of NO_X formation (reducing peak flame temperature); introduce inerts (combustion products, for example) that limit initial NO_X formation; or both. Post-combustion NO_X control technologies for the GE gas turbine include various strategies to chemically reduce NO_X to elemental nitrogen (N_2) with or without the use of a catalyst.

NO_X combustion control techniques for the General Electric turbine include: Water or Steam Injection; Combustion Liner Upgrade with Low NO_X Burner Design; and Good Combustion Practices. NO_X post-combustion control techniques for the General Electric turbine include: EM_X™/$SCONO_X$™ Technology; Selective Catalytic Reduction (SCR); and Selective Non-Catalytic Reduction (SNCR).

2.5.1.1.1 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.

2.5.1.1.2 Combustion Liner Upgrade with Low NO_X Burner Design:

The liner of a turbine surrounds the combustion process and allows for various airflows to pass through 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-NO_X (DLN) combustion technology, is a pollution prevention technology that 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. 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. Since NO_X formation rates are an exponential function of temperature and turbines having frequent and rapid load changes, they may experience a brief spike in NO_X emissions with DLN technology.

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.

2.5.1.1.3 EM_X™/$SCONO_X$™ Technology:

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.

2.5.1.1.4 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 are expressed as:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

$$2\ NO_2 + 4\ NH_3 \rightarrow 3\ N_2 + 6\ H_2O$$

Variable loads at the compressor station can pose operational issues that can affect the effectiveness of SCR as a control option. 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 lead to ammonia slip (nonreacted NH_3 being emitted to the atmosphere).

2.5.1.1.5 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 NO_X to nitrogen and water. The overall reaction schemes for both urea and ammonia systems are expressed as:

$$CO(NH2)2 + 2\ NO + \tfrac{1}{2}\ O2 \rightarrow 2\ N2 + CO2 + 2H2O$$

$$4\ NH3 + 6NO \rightarrow 5\ N2 + 6\ H2O$$

This add-on technology is similar to SCR; however the reduction of NOX 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.

2.5.1.1.6 Good Combustion Practices:

NO_X emissions are caused by 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 operation of the units can be developed and maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for 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.

2.5.2 Four-Factor Analysis Review

2.5.2.1 Technical Feasibility

2.5.2.1.1 Water/Steam Injection:

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 could cause turbine damage, such as corrosion and/or the formation of deposits in the hot section of the turbine.

High- purity water will be an expensive retrofit because the Williams Compressor Station currently does not have a water treatment system on site. Moreover, the consumption of water will be very high for the large turbine. Besides being an added expense, such high water usage may pose problems for the local water supply. This is important especially in dry regions such as Arizona.

Although water/steam injection reduces NO_X emissions, the lower average temperature within the combustor may produce higher levels of CO and hydrocarbons because of incomplete combustion. Additionally, water/steam injection results in decreased combustion efficiency and increased maintenance requirements due to wear on the turbine and combustor.

Water/Steam Injection is determined to be technically feasible for the GE gas turbine at the Williams Compressor Station and therefore were included in the four-factor analysis.

2.5.2.1.2 Combustion Liner Upgrade with Low NO_X Burner Design:

For existing turbines, the combustion chamber would need to be redesigned and reconfigured to allow for lean premixing and/or fuel staging.

DLN control technology combined with a liner upgrade is an available option for the GE Frame 5 gas turbine. EPNG was able to obtain a cost estimate from GE for the control technology; as such, **DLN is considered technically feasible** for the GE gas turbine and was included in the four-factor analysis.

Note that the DLN combustion technology requires conversion of the GE gas turbine from regenerative cycle to simple cycle. The simple cycle conversion of the turbine will have adverse impacts on the efficiency of the gas turbine, increasing fuel usage up to 40%.

2.5.2.1.3 EMx™/SCOnox™ Technology:

The catalyst is installed in the flue gas with a temperature range between 300°F to 700°F.

The GE gas turbine at the Williams Compressor Station is a regenerative-cycle turbine, with an exhaust temperature greater than 900 °F. $EM_X^{TM}/SCONO_X^{TM}$ applications on turbines with outlet temperatures this high have not been identified. Consequently, it was concluded that **$EM_X^{TM}/SCONO_X^{TM}$ is not technically feasible** for control of NO_X emissions from the GE turbine and was excluded from the Four-factor analysis.

2.5.2.1.4 Selective Catalytic Reduction (SCR):

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. The exhaust temperature of the GE gas turbine is above 900°F which is greater than the upper limit of 850°F. Per AP-42 Section 3.1, at this temperature, NO_X and NH_3 can pass through the catalyst unreacted. Based on the exhaust temperature range of the turbine, a flue gas-cooling scheme would be required to make SCR a technically feasible technology for this unit. Because a temperature differential of 50-100°F can be achieved by commonly used technology, **SCR was considered technically feasible** and was included in the four-factor analysis.

Though considered technically feasible, it should be noted that there are several operational issues which could 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 nonreacted NH_3 emitted to the atmosphere (known as “ammonia slip”). This ratio is difficult to control in units which 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 increasing load and nonreacted NH_3 emissions (“ammonia slip”) to increase during periods of load loss.

2.5.2.1.5 Selective Non-Catalytic Reduction (SNCR):

An important consideration for implementing SNCR is the operating temperature range. The optimum temperature range is approximately 1,600 to 2,000°F. Operation at temperatures below this range results in ammonia slip (when non-reacted NH_3 emitted to the atmosphere).

The temperature range required for effective operation of this technology is well above the peak exhaust temperature for the GE gas turbine. In order to make SNCR a possibility, the temperature of the exhaust gas stream would need to be increased a minimum of 700°F. For this reason, it was determined that **SNCR is not technically feasible** for the GE gas turbine at Williams Compressor Station and was therefore excluded from the four-factor analysis.

2.5.2.1.6 Good Combustion Practices (Base Case):

Utilizing good combustion practices and fuel selection was identified in this review of the RBLC 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 turbine at Williams Compressor Station. EPNG has developed Turbine Inspection and Maintenance Schedules Best Practices procedures, which are based on manufacturer recommendation, 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 Williams Compressor Station. No further assessment of these control practices is included in this report.

Table 11 lists the evaluated control options for the General Electric turbine. Good combustion practice is currently in use at the facility. In addition to good combustion practice, two combustion control options were determined to be technically feasible for TURBINE-1: water or steam injection and combustion liner upgrade with low NO_X burner design.

Table 11: Evaluated Controls TURBINE-1

TURBINE-1 Control Options	Technically Feasible (Y/N)	Pollutant Impacted	Control Effectiveness (%)
Water or Steam Injection	Y	NO_X	75
Combustion Liner Upgrade and Low NO_X Burner Design	Y	NO_X	79

EM_X™/$SCONO_X$™ Technology	N	NO_X	N/A
Selective Catalytic Reduction (SCR)	N	NO_X	N/A
Selective Non-Catalytic Reduction (SNCR)	N	NO_X	N/A
Good Combustion Practices (Base Case)	Y	NO_X	Currently in use

2.5.2.2 Cost of Compliance

The cost of each control technology was estimated using published methods, vendor quotes, and turbine characteristics.

2.5.2.2.1 Water or Steam Injection:

Capital cost for the injection system and the water treatment facility were obtained from vendor quote. Taxes, freight, installation (direct and indirect), and contingency cost were estimated using EPA "Alternative Control Techniques Document - NO_X Emissions from Stationary Turbines 1993.

Annual costs included water treatment expenses, a 3.5% fuel penalty for water injection, and a 1% fuel penalty for steam injection. For steam injection, fuel cost for a boiler was included. Added maintenance was estimated using Cost Analysis of NO_X control Alternatives for Stationary Gas Turbines, 1999. Plant overhead was estimated using Alternative Control Techniques Document - NO_X Emissions from Stationary Turbines 1993.

Capital cost for a new transformer was obtained from APS quote. $750,000 cost for a new transformer and $250,000 cost for modifying/replacing foundations were included in the cost effectiveness calculations. Total amount ($1,000,000) was divided by 4 to share the cost by three Clark engines and one GE turbine.

Annual quantities were estimated for electricity cost, water use, and water treatment. Electricity cost was based on Williams Compressor Station July 2019 electricity bill. Water waste was estimated at 29% based on EPA's Alternative Control Techniques Document - NO_X Emissions from Stationary Turbines 1993, page 6-213, (1990, $) cost that were converted to 2018 dollars. Water Treatment Cost (1990, $), Labor Cost (1990, $), and Water Disposal Cost (1990, $) were estimated using EPA's Alternative Control Techniques Document - NO_X Emissions from Stationary Turbines 1993, page 6-213, all costs in 1990 dollars.

Overall the cost effectiveness for water injection was estimated at $6,673/ton and steam injection was estimated at $7,702/ton.

2.5.2.2.2 Combustion Liner Upgrade and Low NO_X Burner Design:

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, the indirect installation cost, and the contingency cost. These costs were estimated using EPA "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 systems plus taxes and freight. However, the direct installation cost was reduced from 45% to 15% due to the 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 sum of the systems, taxes and freight, and direct and indirect 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 2028 projected emissions.

2.5.2.2.3 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 SCR design data was obtained from 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.5. The turbine exhaust parameters that were used in the reactor design, were obtained from 2019 Source Test. 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.

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 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.

2.5.2.2.4 Good Combustion Practices:

Currently Good Combustion Practices are practiced at the Williams Compressor Station. As such, there are no additional incurred expenses for this control option.

Table 12: Control Option Cost Effectiveness

Control Options	Capital Cost	Annualized Capital Cost	Annual Operating & Maintenance Cost	Total Annual Cost ($/yr)	Emission Reduction (tpy)	Cost-Effectiveness ($/ton)
Water Injection	$7,136,682	$860,951	$312,800	$1,459,218	218.67	$6,673
Steam Injection	$7,588,563	$915,465	$465,155	$1,684,162	218.67	$7,702
Combustion Liner Upgrade and Low NO_x Burner Design	$9,004,424	$656,268	$184,717	$1,995,490	230.63	$8,652
Selective Catalytic Reduction (SCR)	$4,088,804	$493,263	$1,059,351	$1,794,329	229	$7,822

2.5.2.3 Time Necessary for Compliance

2.5.2.3.1 Water or Steam Injection:

A total of 14 months is the estimated time required to install either steam injection or water injection technology. This estimation is from the EPNG Engineering Department and includes time for engineering, permitting, and installation.

2.5.2.3.2 Combustion Liner Upgrade and Low NO_X Burner Design:

A total of 14 months is the estimated time to install DLN control technology with liner upgrade. This estimation is from EPNG Engineering Department and includes time for engineering, permitting, and installation.

2.5.2.3.3 Selective Catalytic Reduction (SCR):

A total of 14 months is the estimated time to install SCR system. This estimation is from EPNG Engineering Department and includes time for engineering, permitting, and installation.

2.5.2.4 Energy and Non-Air Quality Impacts

2.5.2.4.1 Water or Steam Injection:

Water injection would increase the overall fuel usage of the source because of multiple factors. Injecting water reduces the thermal efficiency of the turbine, thereby requiring more fuel to achieve the necessary power output. Producing and transporting large amount of high purity water to a remote area would use natural resources for fuel and would have associated energy and environmental impacts. A vendor quote estimated that a demineralized water consumption rate of 30 gpm would be required to achieve the desired control efficiency. This is important especially in dry regions such as Arizona. Disposal of waste water is another add-on expense.

2.5.2.4.2 Combustion Liner Upgrade with Low NO_X Burner Design:

The DLN control technology would require the GE gas turbine to be converted from regenerative-cycle to simple-cycle, reducing the heat rate and increasing the fuel usage. A 40% fuel use increase is expected based on the vendor quote. The increased fuel usage will result in additional CO, VOC, and SO2 formation.

2.5.2.4.3 Selective Catalytic Reduction (SCR):

Selective catalytic reduction requires an ammonia storage, handling and delivery system. This includes vaporizers and blowers to prepare the ammonia reagent for injection. Ammonia is listed as a hazardous substance under Title III Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). Storage, transportation, and handling of ammonia increases risk of human exposure. In addition to risks with ammonia, spent catalyst is classified as a hazardous waste. Turbine efficiency would also be affected because an SCR system increases the engine backpressure.

In addition, it should be noted that in order to construct an SCR system, the building that houses the turbine may have to undergo drastic modifications to accommodate the system. Although this was not included in the cost analysis, the cost to modify the current building design could surpass millions of dollars.

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.

2.5.2.5 Remaining Useful Life of Source

According to EPNG, the remaining useful life of the turbine is estimated to be 15 years (after 2025, which is the earliest time that the controls are expected to be installed). The choice of control technology does not affect the remaining useful life of the GE gas turbine.

2.6 Clark Reciprocating Engines

2.6.1 Proposed Control Methodology

2.6.1.1 Evaluated Control and Emission Estimates

NO_X control options for the lean-burn reciprocating engines include: Selective Catalytic Reduction (SCR); Air-Fuel Ratio Adjustment with High Energy Ignition; Low-Emission Combustion (LEC) Retrofits; Replacement of Three Engines with One Low NO_X Emissions Gas Turbine; Replacement of Three Engines with Electric Motors; and Good Combustion Practices.

2.6.1.1.1 Selective Catalytic Reduction (SCR):

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

$$4\ NO + 4\ NH3 + O2 \rightarrow 4\ N2 + 6\ H2O$$

$$2\ NO2 + 4\ NH3 \rightarrow 3\ N2 + 6\ H2O$$

2.6.1.1.2 Air-Fuel Ratio Adjustment:

Air-fuel ratio adjustment can be accomplished with an automatic control system. For lean-burn engines, the amount of air in the combustion process is increased which lowers the combustion temperature and reduces NO_X formation.

2.6.1.1.3 Low-Emission Combustion (LEC) Retrofit:

Many engine manufacturers have created low-emission combustion designs that operate at leaner air to fuel ratios than typical engine designs. Some manufacturers provide retrofit kits for existing engine models that were not pre-installed with this technology.

2.6.1.1.4 Good Combustion Practices:

NO_X emissions are caused by 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 cylinders where pockets of excess oxygen occur. By following concepts from engineering knowledge, experience, and manufacturer's recommendations, good combustion practices for operation of the units can be developed and maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for 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.

Good Combustion Practice has been determined as feasible for the engines at Williams. EPNG has developed Engine Inspection and Maintenance Schedules Best Practices procedures, which are based on manufacturer recommendation, and EPNG has systems in place to ensure that its engines are operated in accordance with this. These practices are currently in use at Williams.

Table 13: Evaluated Controls for RECIP-1, 2, & 5

Control Options	Emission Unit	Technically Feasible (Y/N)	Pollutant Impacted	Control Effectiveness (%)
Selective Catalytic Reduction (SCR)	RECIP-1	Y	NO_X	85
	RECIP-2	Y	NO_X	85
	RECIP-5	Y	NO_X	85
Air-fuel Ratio Adjustment with High Energy Ignition	RECIP-1	Y	NO_X	11
	RECIP-2	N	NO_X	N/A
	RECIP-5	N	NO_X	N/A
Low-Emission Combustion Retrofit (LEC 1, 2, 3)	RECIP-1	Y	NO_X	52/82/97
	RECIP-2	Y	NO_X	40/78/96
	RECIP-5	Y	NO_X	46/80/97
Good Combustion Practice	RECIP-1, 2, & 5	Y	NO_X	Currently in use

2.6.2 Four-Factor Analysis Review

2.6.2.1 Technical Feasibility

2.6.2.1.1 Selective Catalytic Reduction (SCR):

SCR installations typically have an operating range of 450 to 850ºF but can operate at slightly higher temperatures. The exhaust temperatures of all three reciprocating engines are within the range of feasibility, as such, they were included in the four-factor analysis.

However, it should be noted that reciprocating engines having frequent and rapid load fluctuations that can cause variations in exhaust temperature and NO_X concentration which can create problems with the effectiveness of the SCR system.

2.6.2.1.2 Air-Fuel Ratio Adjustment:

Control efficiencies for lean-burn engines are in the range of 5 to 30 percent, with NO_X outputs reduced to as low as 15 g/hp-hr. At Williams Compressor Station, one TLA-6 engine (RECIP-2) and the TLA-10 engine (RECIP-5) already achieve this NO_X emission rate, making the control infeasible for RECIP-2 and RECIP-5. The remaining engine, TLA-6 (RECIP-1), has a NO_X emission rate of nearly 17 g/hp-hr.

Controlled air-fuel ratio adjustment is a feasible control for RECIP-1 and was included in the four-factor analysis.

2.6.2.1.3 Low-Emission Combustion (LEC) Retrofit:

The low-emission combustion design uses improved swirl patterns to increase air/fuel mixing. Often times, a precombustion chamber is also included which lowers combustion temperatures and NO_X emissions. This technology is available for rich-burn engines, lean-burn engines, and dual-fuel engines. This analysis considers three graduated levels of retrofits which will hereinafter be referred to as the following:

- LEC 1: The first level is adding only a high pressure-fuel injection system, referred hereafter as LEC 1.
- LEC 2: The second level adds three systems combined with LEC 1: turbocharger aero, aftercooler, and an air-fuel ratio control; hereafter referred to as a LEC 2.
- LEC 3: The third level adds three new systems to LEC 2: pre-combustion chambers (PCC), electronic PCC valves, and an auto-balance system, hereafter referred to as LEC 3.

These technologies were determined to be feasible and were included in the four-factor analysis.

2.6.2.1.4 Good Combustion Practices:

NO_X emissions are caused by 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 cylinders where pockets of excess oxygen occur. By following concepts from engineering knowledge, experience, and manufacturer's recommendations, good combustion practices for operation of the units can be developed and maintained by training maintenance personnel on equipment maintenance, routinely scheduling inspections, conducting overhauls as appropriate for 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.

Good Combustion Practice was determined as feasible for the engines and was included in the four-factor analysis.

2.6.2.2 Cost of Compliance

The cost of each control technology was estimated using published methods, vendor quotes, and reciprocating engine characteristics. The capital costs of add on controls were amortized over a 20-year period due to the ages of these engines. These annualized capital costs were added to the estimated 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. Below is each feasible NO_X control method for the reciprocating engines and its corresponding results of impact analyses.

2.6.2.2.1 Selective Catalytic Reduction (SCR):

The capital cost for the SCR equipment was obtained from vendor quote. This quote takes into account two (2) engines at the facility which were not subject to this analysis. Those engines can be found in Table 8 above. The facility was quoted $2,751,735 for SCR catalyst for five (5) Clark TLA engines. In addition, new transformers costs were obtained from vendor: $750,000 for like kind replacement from APS email from 5/3/2019. $250,000 was added for modifying/replacement of foundations, contingency cost and taxes and freight. Total amount ($1,000,000) divided by 4 to share the cost by three (3) Clark engines and one (1) GE turbine.

The NO_X Removal Efficiency for SCR was assumed to be 85%. This was estimated using EPA Alternative Control Techniques Document - NOx Emissions from Stationary Reciprocating Internal Combustion Engine EPA-453/R93-032 which states that a typical control efficiency is in the range between 75% and 90%.

The installation (direct and indirect) and contingency costs were determined per EPA Alternative Control Techniques Document - NO_X Emissions from Stationary Reciprocating Internal Combustion Engine EPA-453/R93-032, page 6-52. The direct installation cost was calculated as 25% of equipment cost. The indirect installation cost and the contingency cost were each calculated as 20% of the equipment cost.

In addition, EPA-453/R93-032 was used to estimate operator labor, maintenance cost, and the fuel penalty. The operator labor used was for a 3 hr to 8 hr. time, for a rate of $60/hr. Maintenance cost was estimated as 10% of capital cost. The fuel penalty to compensate for an increase in fuel consumption, was estimated as 0.5% increase in fuel costs.

The electricity rate at Williams Compressor Station was estimated at $0.476/kWhr per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equations 2.48 and 2.49. The Mass

Flow of Reagent (lb/hr) was estimated per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.35. The volume of catalyst required (ft^3) was assumed to be 1.3 m^3/MW. Annual cost for catalyst cleaning was estimated at $0.5/hp plus 10% freight per EPA453/R-93-032 pg. 6-54. This cost is adjusted to 2018 dollar. Finally, the indirect operating cost, including administrative, taxes, and insurance ($/yr) were estimated at 4% of Capital Cost per EPA Air Pollution Control Cost Manual, Seventh Ed., 2017, Sect. 2.6.5.8, pg 2-35.

In addition, it should be noted that in order to construct an SCR system, the building that houses the engines may have to undergo drastic modifications to accommodate the system. Although this was not included in the cost analysis, the cost to modify the current building design could surpass millions of dollars.

2.6.2.2.2 Air-Fuel Ratio Adjustment:

The equipment cost for the air-fuel ratio controller was obtained from a vendor email to EPNG (sent July 30, 2019). The cost of taxes and freight were determined using the Arizona rate of 9.15%. Installation cost was assumed to be 20% of the equipment. The total capital cost was calculated as the sum of taxes and freight, installation cost, and equipment cost.

The fixed operating cost includes operating labor, maintenance, testing, and electricity estimates. These values were obtained by EPNG from multiple vendor quotes found in RACT analyses prepared for Colorado Interstate Gas Company compressor stations. The fixed operating costs were then adjusted from 1993 dollars to 2018 dollars. The overhead for this project was assumed to be 60% of the O&M costs. Administrative costs, insurance, and taxes were assumed to be 4% of the total capital cost.

2.6.2.2.3 Low-Emission Combustion (LEC) Retrofit:

Equipment cost for LEC 1 – LEC 3 were obtained from vendor emails to EPNG (sent June 3, 2019 and July 30, 2019). The equipment costs includes the vendor quoted control equipment cost (LEC 1 -$530K, LEC 2 - $830K, and LEC 3 – $470K) , the control panel upgrade at $250,000, and the off-engine fuel system modifications at $500,000.

The updates for LEC are successive, (i.e. LEC3 includes the improvements of LEC 1 and LEC 2). The costs for the LEC options are comprised of the following:

- LEC 1 (Hoerbiger cost of $530,000)
  - HyperFuel (LEC1)
- LEC 2 (Hoerbiger cost of $830,000)
  - Turbocharger re-aero w/Aftercoolers and
  - A/F Ration Controls
  - Costs for LEC1.
- LEC 3 (Hoerbiger cost of $470,000)
  - PCC System w/ePCC System and
  - HyperBalance
  - Costs for LEC1 and LEC2

Costs for the new transformers costs were obtained from vendor: $750,000 for like kind replacement from APS email from 5/3/2019. $250,000 was added for modifying/replacement of foundations, contingency cost and taxes and freight. Total amount ($1,000,000) divided by 4 to share the cost by three Clark engines and one GE turbine.

The contingency costs were determined per methods in "EPA Alternative Control Techniques Document - NO_X Emissions from Stationary Reciprocating Internal Combustion Engine." Based on the methodology, the contingency costs are 20% of the equipment cost.

The annual operating and maintenance costs were determined using methods from "EPA Alternative Control Techniques Document - NO_X Emissions from Stationary Reciprocating Internal Combustion Engine". The Annual Operating cost includes spare parts for the control technology, operating and maintenance labors, annual reference test and indirect operating costs. The administrative costs, insurance, and taxes were determined by using 4% of the total capital cost.

Table 14: Control Option Cost Effectiveness

Control Options	Emission Unit	Capital Cost	Annualized Capital Cost	Annual Operating & Maintenance Cost	Total Annual Cost ($/yr)	Emission Reduction (tpy)	Cost-Effectiveness ($/ton)
Selective Catalytic Reduction (SCR)	RECIP-1	$1,173,942	$124,323	$517,684	$815,528	126.14	$6,465
	RECIP-2	$1,172,987	$124,222	$572,492	$888,753	144.84	$6,136
	RECIP-5	$1,175,939	$124,534	$846,110	$1,166,410	174.39	$6,689
Air-Fuel Ratio Adjustment with High Energy Ignition	RECIP-1	$200,183	$21,200	$13,742	$51,194	16.21	$3,158
Low-Emission	RECIP-1	$1,750,000	$185,328	$42,762	$298,090	84.64	$3,522
	RECIP-2	$1,750,000	$185,328	$42,762	$298,090	85.50	$3,487

Combustion Retrofit (LEC 1)	RECIP-5	$1,750,000	$185,328	$51,502	$306,830	54.20	$5,661
Low-Emission Combustion Retrofit (LEC 2)	RECIP-1	$3,250,000	$344,181	$46,411	$520,592	124.49	$4,182
	RECIP-2	$3,250,000	$344,181	$46,411	$520,592	138.56	$3,757
	RECIP-5	$3,250,000	$344,181	$55,151	$529,332	148.55	$3,563
Low-Emission Combustion Retrofit (LEC 3)	RECIP-1	$4,150,000	$439,493	$83,478	$688,971	144.42	$4,771
	RECIP-2	$4,150,000	$439,493	$83,478	$688,971	165.09	$4,173
	RECIP-5	$4,150,000	$439,493	$101,337	$706,830	195.72	$3,611

2.6.2.3 Time Necessary for Compliance

2.6.2.3.1 Selective Catalytic Reduction (SCR):

For each engine, it is estimated that a total of 14 months will be needed to install SCR control technology. This estimation was provided by the EPNG Engineering Department. The 14 months includes the time for engineering, permitting, and installation of the SCR control technology.

2.6.2.3.2 Air-Fuel Ratio Adjustment:

The EPNG Engineering Department estimates that a total of 14 months is needed to install automatic air-fuel ratio adjustment on RECIP-1. The 14 months includes the time for engineering, permitting, and installation of automatic air-fuel ratio adjustment.

2.6.2.3.3 Low-Emission Combustion (LEC) Retrofit:

It is estimated that a total of 14 months is needed to install these controls for each engine. This estimation is from EPNG Engineering Department and includes time for engineering, permitting, and installation.

This estimation is the same for LEC 1 – 3.

2.6.2.4 Energy and Non-Air Quality Impacts

2.6.2.4.1 Selective Catalytic Reduction (SCR):

Selective catalytic reduction requires an ammonia storage, handling and delivery system. This includes vaporizers and blowers to prepare the ammonia reagent for injection. Ammonia is listed as a hazardous substance under Title III Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). Storage, transportation, and handling of ammonia increases risk of human exposure. In addition to risks with ammonia, spent catalyst is classified as a hazardous waste. Engine efficiency would also be affected because an SCR system increases the engine backpressure.

In addition, it should be noted that in order to construct an SCR system, the building that houses the engines may have to undergo drastic modifications to accommodate the system. Although this was not included in the cost analysis, the cost to modify the current building design could surpass millions of dollars.

These reciprocating engines have frequent and rapid load fluctuations which can cause variations in exhaust temperature and NO_X concentration which can create problems with the effectiveness of a SCR system.

2.6.2.4.2 Air-Fuel Ratio Adjustment:

Implementation of the automatic air-fuel ratio adjustment on RECIP-1 would result in more complete fuel combustion. This increase in complete fuel combustion (an increased extraction of a larger amount of energy from fuel) would result in reduced fuel consumption for RECIP-1.

Note, this option is technically feasible for RECIP-1 only.

2.6.2.4.3 Low-Emission Combustion (LEC) Retrofit:

The High-Pressure Fuel Injection System requires electricity to operate. To generate the necessary electricity, there would need to be an increase in fuel combustion. An increase in fuel combustion would lead to an increase in emissions. In addition, the installation of a new transformer may be necessary but is not included in the cost analysis. However, EPNG estimates a new transformer could cost millions to install.

2.6.2.5 Remaining Useful Life of Source

According to EPNG, other Kinder Morgan entities have similar engines that are still in operation even after 70 years of service. The oldest known engine is 79 years old, with the average age being 64 years old. For reference RECIP - 1 and - 2 are from 1956 (currently 64 years old) and RECIP -5 is from 1960 (currently 60 years old). Since the parts for the engines are still available and similar engines have proven to remain operational for longer, EPNG has stated that there were no plans to retire the engines.

However, since a concrete age of retirement could not be determined, for purposes of this analysis 20 years was determined as a reasonable assumed remaining useful life. The choice of control technology does not affect the remaining useful life of the reciprocating engines. EPNG estimates that the earliest date in which the controls can be installed is 2025.

2.7 Process Equipment Replacements for RECIP-1, 2, & 5

2.7.1 Proposed Control Methodology

2.7.1.1 Evaluated Control and Emission Estimates

To minimize the creation of NO_X, EPNG considered the replacement of the three reciprocating engines with lower NO_X emitting or electric equipment. The process equipment considered includes: replacing the three engines with one low NO_X gas turbine and replacing the three engines with three electric motors.

2.7.1.1.1 Replacement of Three Engines with One Low NO_X Gas Turbine:

In comparison, a new gas turbines is typically superior in power output and emissions to older reciprocating engine. In this case, one high capacity gas turbine could be used to replace multiple reciprocating engines. For this analysis, EPNG assumed that a Solar Mars 100 gas turbine (15,900 hp) would replace the three reciprocating engines.

2.7.1.1.2 Replacement of Three Engines with Three Electric Motors:

Electrical motors do not directly release emissions. Instead, the electrical motors require electricity as a source of power. Therefore, by replacing the three reciprocating engines with three electric motors, there would be a complete reduction in NO_X emissions from the engines. There are no barriers to technical feasibility for the installation of electric motors. The motors could be installed in place of the reciprocating engines.

Table 15: Evaluated Process Equipment Replacements for RECIP-1, 2, & 5

RECIP-1, 2, & 5 Control Option	Technically Feasible (Y/N)	Pollutant Impacted	Control Effectiveness (%)
Replacement Of Three Engines With One Low NO_X Emissions Gas Turbine	Y	NO_X	90
Replacement Of Three Engines With Electric Motors	Y	NO_X	100

2.7.2 Four-Factor Analysis Review

2.7.2.1 Technical Feasibility

2.7.2.1.1 Replacement of Three Engines with One Low NO_X Gas Turbine:

It was assumed that a Solar Mars 100 gas turbine (15,900 hp) would replace the three reciprocating engines. The complete replacement of three reciprocating engines with a Solar Mars 100 gas turbine is technically feasible and was included in the four-factor analysis.

2.7.2.1.2 Replacement of Three Engines with Three Electric Motors:

The electric motors have no technical barriers to feasibility and could be installed at the site in place of individual reciprocating engines to reduce direct fuel burning emissions. This option is technically feasible and was included in the Four-factor analysis.

2.7.2.2 Cost of Compliance

The cost of each process equipment replacement was estimated using published methods, vendor quotes, and the characteristics of the reciprocating engines. The initial capital costs of engine replacements were amortized over a 20-year period. These annualized capital costs were added to the estimated operating costs. An interest rate of 8.53% was used in the calculations. Below is each feasible NO_X control method for the reciprocating engines and its corresponding results of impact analyses.

The replacement of the three reciprocating engines with process equipment is not the same as adding a pollution control device since the engines are eventually going to be retired and replaced. The ADEQ proposed a new methodology for including this early retirement into the cost of the equipment replacement. This methodology was not applied to the replacement with the electric motors because the cost was significantly higher than what would be considered reasonable.

2.7.2.2.1 Replacement of Three Engines with One Low NO_X Gas Turbine:

2.7.2.2.2 EPNG's Proposed Method:

The cost for the equipment was obtained from a September 24, 2019 email with a vendor. Capital cost for a new transformer was obtained from APS quote. $750,000 cost for a new transformer and $250,000 cost for modifying/replacing foundations were included in the cost effectiveness calculations. Total amount ($1,000,000) was divided by 4 to share the cost by three Clark engines and one GE turbine

The administrative costs, insurance, and taxes were determined by using 4% of the total capital cost per EPA Air Pollution Control Cost Manual, Seventh Ed., 2017, Section. 2.6.5.8. To determine the cost for maintenance and materials, the actual cost was obtained for maintaining a Solar Mars 100 at Seligman Compressor Station, AZ for 2019.

2.7.2.2.3 ADEQ's Proposed Method

Since the replacement of the three reciprocating engines with a new gas turbine is not the same as installing a control device, the ADEQ applied a different methodology to determining the cost effectiveness for this option. The ADEQ proposes that the capital cost should reflect the cost associated early retirement of the three reciprocating engines and the installation of a low NO_X Turbine early. The ADEQ also proposes that 50 years is a more accurate estimate of useful life for a turbine.

The ADEQ assumed that the three engines would be naturally retired in twenty years (2038) based on the information submitted by EPNG. Due to the Regional Haze program the engines are assumed to be retired 10 years early (2028), to meet the requirements of the program. The ADEQ refers to this as early retirement.

The incremental annual cost of a gas turbine was determined and compared to the continued use of the three engines. The incremental annual cost was then utilized to calculate the cost effectiveness ($/ton) for the early installation period. Due to the age of the engines, the costs of operation and maintenance (O&M) of the engines were determine and the capital costs were not factored in. This provided a more conservative estimate.

Using this calculation methodology, the low NO_X turbine was determined to be a cost effective option.

2.7.2.2.4 Replacement of Three Engines with Electric Motors:

The capital cost for the equipment was obtained from a September 24, 2019 vendor email. The cost was $1,469 per horsepower rating for each motor added to a value of $3,500,000.

The administrative costs, insurance, and taxes were determined by using 4% of the total capital cost. The electricity cost assumed an electricity rate of $0.4764/kWh based on July 2019 electricity bill for Williams Compressor Station.

Though the replacement of the engines with electric motors is not the equivalent of installing an air pollution control device, the ADEQ did not develop a cost feasibility calculation. The total capital cost associated with this replacement is between three and four times more expensive than the low NO_X turbine option. Thus, applying this methodology is assumed not to show the electric engines as a cost effective option.

Table 16: Control Option Cost Effectiveness

Control Options	Emission Unit	Capital Cost	Annualized Capital Cost	Annual Operating & Maintenance Cost	Total Annual Cost ($/yr)	Emission Reduction (tpy)	Cost-Effectiveness ($/ton)
Replacement Of Three Engines With One Low NO_X Emissions Gas Turbine	RECIP-1, 2, & 5	$26,600,426	$2,817,036	$586,656	$4,467,709	470.2	$9,501
		$26,600,426*	$2,358,265*	$2,569,650*	$1,890,594*	470.2*	$4,021*
Replacement Of Three Engines With Electric Motors	RECIP-1	$4,104,667	$434,692	$2,568,468	$3,167,347	148.4	$21,343
	RECIP-2	$4,104,667	$434,692	$3,420,361	$4,019,240	170.4	$23,587
	RECIP-5	$6,161,267	$652,490	$6,081,550	$6,980,491	205.2	$34,025

* Cost takes into account early retirement of the reciprocating engines

2.7.2.3 Time Necessary for Compliance

2.7.2.3.1 Replacement of Three Engines with One Low NO_X Gas Turbine:

It is estimated that a total of 18 months is needed to replace the three Clark engines with a low NO_X emission gas turbine. This estimation is from EPNG Engineering Department and includes time for engineering, permitting, and installation.

2.7.2.3.2 Replacement of Three Engines with Electric Motors:

A total of 18 months for each engine is the estimated time to install the controls. This estimation is from EPNG Engineering Department and includes time for engineering, permitting, and installation.

2.7.2.4 Energy and Non-Air Quality Impacts

2.7.2.4.1 Replacement of Three Engines with One Low NO_X Gas Turbine:

The complete replacement of three reciprocating engines with a Solar Mars 100 gas turbine would require significant capital investment, extensive engineering oversight, and the compressor station off-line for an extended period, causing service interruption to end users and natural gas suppliers.

In addition, the use of three separate reciprocating engines at Williams Compressor Station allows flexibility in the operation of the facility. Based on the needs of the network, the conditions of the pipeline, and the horsepower required the engines can be turned on or off to meet the situation. This is essential to control small pipeline flowrate changes.

Replacing the three engines with a single, large turbine would result in an increase of emissions. During low flow operating conditions, the turbine would not have enough flow to operate efficiently. Operating in these conditions would require the turbine to be in recycle mode, a process that causes the turbine to recompress gas over and over.

Overall the replacement would result in an overall loss of flexibility, an increase in fuel usage, and it is unlikely that emissions reductions would be as great as those presented in the above analysis.

2.7.2.4.2 Replacement of Three Engines with Electric Motors:

The complete replacement of the three reciprocating engines with electrical motors would require electricity as a source of power. Since more electricity would be needed at the facility, the installation of a new electric utility line and a transmission sub-station would be required.

These new electricity needs at the facility would result in higher electricity consumption and demand from power plants. Since generating electricity involves fuel combustion (from coal and oil-fired power plants), there would be an increase of NO_X, CO, and VOC emissions at those facilities. In addition, it would require initial capital, engineering oversight, and downtime, causing service interruption to end users and natural gas suppliers.

2.7.2.5 Remaining Useful Life of Source

2.7.2.5.1 Replacement of Three Engines with One Low NO_X Gas Turbine:

EPNG estimates that the earliest date in which the replacement of three engines with the low NO_X gas turbine can be accomplished is 2025. The EPNG engineering team made the assumption that the new gas turbine would operate for 20 years after 2025 to fully amortize the cost of the replacement, while ADEQ assumed 50 years.

2.7.2.5.2 Replacement of Three Engines with Electric Motors:

EPNG estimates that the earliest date in which the replacement of three engines with electric motors can be accomplished is 2025.