REGIONAL HAZE FOUR-FACTOR ANALYSIS

El Paso Natural Gas Company LLC
Pecos River Compressor Station

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1. INTRODUCTION

In the 1977 amendments to the Clean Air Act (CAA), Congress set a nation-wide goal to restore national parks and wilderness areas to natural conditions by remedying existing, anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across the United States, known as Federal Class I areas. The CAA defines Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires states to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their jurisdiction. In establishing a reasonable progress goal for a Class I area, each state must:

(A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal. 40 CFR 51. 308(d)(1)(i)(A).

This is known as a four-factor analysis.

(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction. 40 CFR 51. 308(d)(1)(i)(B).

The uniform rate of progress or improvement is sometimes referred to as the glidepath and is part of the state's Long-Term Strategy (LTS).

The second implementation planning period (2018-2028) for national regional haze efforts is currently underway. There are a few key distinctions from the processes that took place during the first planning period (2004-2018). Most notably, the second planning period analysis distinguishes between natural or biogenic and manmade or anthropogenic sources of emissions. Using a Photochemical Grid Model (PGM), the Western Region Air Partnership (WRAP), in coordination with the EPA, is tasked with comparing anthropogenic source contributions against natural background concentrations.

Pursuant to 40 CFR 51.308(d)(3)(iv), the states are responsible for identifying the sources that contribute to the most impaired days in the Class I areas. To accomplish this, the New Mexico Environment Department (NMED) reviewed 2016 emission inventory data for major sources and assessed each facility's impact on visibility in Class I areas with a "Q/d" analysis, where "Q" is the magnitude of emissions that impact ambient visibility and "d" is the distance of a facility to a Class I area. From this analysis, 24 facilities were identified by the NMED. On July 18, 2019 the NMED informed El Paso Natural Gas Company LLC (EPNG) that its Pecos River Compressor Station (Pecos River) facility was identified as one of the sources potentially contributing to regional haze at the Carlsbad National Park Class I area.

In coordination with WRAP, the NMED devised criteria to determine specific equipment that is subject to the four-factor analysis. In the NMED's July 18, 2019 notification letter to EPNG, it specifies that any equipment with a potential to emit (PTE) greater than 10 pounds per hour (lb/hr) and 5 tons per year (tpy) of Nitrogen Oxides (NO_X) or Sulfur Dioxide (SO_2) shall be included in this analysis. The equipment at Pecos River, the PTE associated with that equipment, and the applicability of a four-factor analysis for each pollutant are reported in Table 1.

Table 1. Summary of Equipment and Applicability to a Four-Factor Analysis

Equipment	NO_X Hourly PTE (lb/hr)	NO_X Annual PTE (tpy)	NO_X Subject to Analysis? (Yes/No)	SO_2 Hourly PTE (lb/hr)	SO_2 Annual PTE (tpy)	SO_2 Subject to Analysis? (Yes/No)
Natural Gas-Fired Regenerative Cycle Turbine (Unit A-01)	53.10	232.58	Yes	0.43	1.87	No
Natural Gas-Fired Regenerative Cycle Turbine (Unit A-02)	53.10	232.58	Yes	0.43	1.87	No
Natural Gas-Fired Regenerative Cycle Turbine (Unit A-03)	53.10	232.58	Yes	0.43	1.87	No

NO_X is the only pollutant subject to evaluation in this four-factor analysis for the three turbines located at Pecos River: Units A-01, A-02 and A-03. These units are General Electric (GE) model M3712R (also known as Model A turbines) natural gas-fired, regenerative cycle turbines. They are rated at 7,150 horsepower each and were manufactured in 1953.

Once the applicability of equipment and pollutants has been determined, potential retrofit control technologies must be identified. In accordance with 40 CFR 51 Appendix Y and at the recommendation of the NMED[1], this is primarily achieved by utilizing the Reasonably Available Control Technology (RACT) / Best Available Control Technology (BACT) / Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) data. In order to determine the most relevant and current retrofit controls available, the RBLC is queried for the previous ten years. A summary of identified available retrofit controls along with a technical feasibility assessment for each control is provided in Section 2. The four-factor analysis is then conducted for those controls that are technically feasible.

[1] NMED 2021 Regional Haze Planning Website ("Links to other information"). https://www.env.nm.gov/air-quality/reg-haze/

2.1. COMBUSTION TURBINE BACKGROUND

A gas turbine is an internal combustion engine that operates with a rotary, rather than reciprocating, motion and is composed of three primary components: a compressor, a combustor, and a power turbine. The compressor draws in ambient air and compresses it up to 30 times the ambient pressure, then directs it into the combustor where fuel is introduced, ignited, and burned. Exhaust gas from the combustor is then diluted with additional air and sent to the power turbine at temperatures up to 2600 °F. The hot exhaust gas expands in the power turbine section, generating energy in the form of shaft horsepower.[2]

The treatment of the exhaust gases exiting the turbine dictate the cycle designation of these units. The heat content can either be discarded without heat recovery (simple cycle); recovered with a heat exchanger to preheat combustion air entering the combustor (regenerative cycle); recovered in a heat recovery steam generator to raise process steam, with or without supplementary firing (cogeneration); or recovered, with or without supplementary firing, to raise steam for a steam turbine Rankine cycle (combined cycle or repowering).[3] The units at Pecos River are regenerative cycle turbines, which are essentially simple cycle gas turbines with an added heat exchanger.

NO_X is formed in turbines via three mechanisms:

(1) Thermal NO_X - the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules during combustion,
(2) Fuel NO_X - the evolution and reaction of fuel-bound nitrogen compounds with oxygen, and
(3) Prompt NO_X - the early reactions of nitrogen intermediaries and hydrocarbon radicals in fuel.

The Pecos River turbines use natural gas fuel, which contains a negligible amount of nitrogen compounds. Therefore, the formation of prompt and fuel NO_X will be insignificant. This analysis will focus on thermal NO_X. The rate of NO_X formation through the thermal NO_X mechanism is highly dependent upon the air-to-fuel ratio, combustion temperature, and residence time in the combustion chamber. Maximum thermal NO_X formation occurs near the stoichiometric air-to-fuel mixture ratio because combustion temperatures are greatest at this ratio.[4]

The PTE from each turbine is reported in the facility's New Source Review (3260M1) and Title V (P129R3M1) permits, as well as summarized in Table 1 of this report.

2.2. POTENTIAL NO_X CONTROLS FOR COMBUSTION TURBINES

There are three general methods of controlling NO_X emission from gas turbines; (1) dry controls, which use advanced combustor design to suppress NO_X formation, (2) wet controls that use steam or water injection to reduce combustion temperatures and NO_X formation, and (3) post-combustion, catalytic controls to selectively reduce NO_X.[5]

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[2] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines"
[3] Ibid.
[4] Ibid.
[5] Ibid.

The retrofit control equipment that was identified for combustion turbines during a comprehensive review of the RBLC, available literature, and manufacturer's input is reported in Table 2. A more detailed table summarizing the RBLC review is provided in Appendix A. A detailed discussion, including a description, the technical feasibility, and the anticipated performance of each control is provided below.

Table 2. Potential Control Options for Combustion Turbines

Control Equipment	Technically Feasible?	NO_X Control Efficiency
Good Combustion Practices	Yes	Base Case
Lean Head End Liner	No	N/A
Improved Combustion Technology	No	N/A
Water/Steam Injection	No	N/A
Selective Catalytic Reduction	Yes	65% - 90%

2.2.1. 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 cylinder 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.

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 units at Pecos River. EPNG has developed Turbine Inspection/Maintenance Schedules Best Practices procedures, included in Appendix B of this report, 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 Pecos River as required by various conditions in its Title V and NSR permit authorizations. No further assessment of these control practices is included in this report.

2.2.2. Lean Head End Combustion Liner

The key factors affecting thermal NO_X formation are the combustion temperature and residence time of fuel in the combustor. Maximum thermal NO_X formation occurs near the stoichiometric air-to-fuel mixture ratio because combustion temperatures are greatest at this ratio. "Lean" combustion refers to combustion occurring at a high air-to-fuel ratio, which reduces the firing temperature.

A Lean Head End (LHE) Combustion Liner is an enhanced liner for the combustion chamber that increases the air-to-fuel ratio by adjusting the number, diameter, and location of the mixing and dilution holes in the chamber.

This diverts excess air toward the flame end, thereby reducing the flame temperature and NO_X formation. GE estimates that NO_X reduction from this control method varies from 15% to 40%, depending upon the design.[6]

Based on communications with GE, there are currently no LHE liner control options for the GE Model A turbines. The earliest model on which the LHE liner can be installed is the Model J generation, which was produced starting in 1969 and has significant design differences to the Model A fleet. The LHE liner control technology has never been installed on units older than the Model J, and there is no way to determine what, if any, emissions reduction could be achieved through a retrofit.

Per 40 CFR Part 51, Appendix Y, "a technology is considered 'available' if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term."[7] Further, source owners are not expected to "construct a process or control device that has not already been demonstrated in practice."[8] Because LHE liners are not currently available for and have never been installed on the Model A fleet of turbines, there is no historical data to support that installation of these controls would result in significant reductions of NO_X emissions. For this reason, it has been determined that this control technology is infeasible for the turbines located at Pecos River.

2.2.3. Improved Combustion Technology

The improved combustion technology control option, commonly referred to as Dry Low NO_X (DLN) control, also seeks to reduce the combustion temperature and residence time of fuel in the combustor (thereby decreasing NO_X formation) by increasing the air-to-fuel ratio in the combustion chamber. There are several levels of improvements that can be made to the combustion chamber, which achieve this NO_X control at varying efficiencies.

Based on communications with GE, the DLN control option involves a thorough overhaul of the combustion section of the turbine, including replacement of the air and fuel injection nozzles, modifications to, or complete replacement, of the combustion chamber, and replacement of the electrical control system for the unit.

As with the LHE liners, there are currently no developed improved combustion controls available for the Model A fleet of GE turbines. The earliest model on which the DLN technology can be installed is the Model J turbines, and the technology has never been retrofitted for units older than the Model J. There is no way to determine what, if any, emissions reduction could be achieved through a retrofit. As there is no historical data to support that significant reductions of NO_X emissions would result from installation of this control, it has been determined that this control technology is infeasible for the turbines located at Pecos River.

2.2.4. Water/Steam Injection

Water or steam injection is a control technology for gas turbines that has been demonstrated to effectively suppress NO_X emissions. Injection of steam and water has the effect of increasing the thermal mass by dilution and thereby reducing the peak temperature in the flame zone. There is an additional benefit of absorbing the latent heat of vaporization from the flame zone when water injection is utilized. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.[9]

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[6] General Electric Power Systems, GER-4211, "Gas Turbine Emissions and Control", 03/2001
[7] 40 CFR 51, Appendix Y, Section IV.D.2
[8] 40 CFR 51, Appendix Y, Section IV.D.1
[9] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines"

Water/steam injection was not identified in this review of RBLC as a potential control of NO_X emissions from natural gas-fired combustion turbines; however, AP-42 Section 3.1 does list water/steam injection as an available control technique for gas turbines.[10]

However, communications with GE have indicated that water/steam injection is not currently available for the Model A turbines located at Pecos River. The technology has never been retrofit for units older than the Model J, and there is no way to determine what, if any, emissions reduction could be achieved through a retrofit. Furthermore, GE has indicated that they have since retired this control option and do not recommend water injection be installed to control emissions from any of their turbine units. As this technology has never been installed on any GE Model A turbine, there is no historical data to support that installation of these controls would result in significant reductions of NO_X emissions. For this reason, it has been determined that this control technology is infeasible for the turbines located at Pecos River.

2.2.5. Selective Catalytic Reduction Systems

Selective Catalytic Reduction (SCR) is the process by which a nitrogen-based reagent, such as ammonia or urea, is injected into the exhaust of a combustion unit. Within a reactor vessel containing a metallic or ceramic catalyst, the injected reagent reacts selectively with the NO_X in the exhaust to produce molecular nitrogen (N_2) and water (H_2O).[11] The chemical reactions for this process are shown in the equations below.

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

An SCR system includes the catalyst, catalyst housing, reagent storage tank, reagent injector, reagent pump, pressure regulator, and an electronic control system. The electronic controls regulate the quantity of reagent injected as a function of turbine load, speed, and temperature, so NO_X emissions reductions can be achieved. The lifespan of the catalyst is primarily determined by poisoning of active sites by flue gas constituent, thermal sintering, or compacting, of active sited due to high temperatures in the reactor, fouling caused by ammonia-sulfur salts and particulate matter in the gas, and erosion due to high gas velocities.[12]

Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as ammonia slip. Unreacted ammonia in the exhaust can form ammonium sulfates which may plug or corrode downstream equipment. As urea is an ammonia precursor, ammonia slip will occur regardless of the reagent employed. Ammonium sulfate-laden streams may blind the catalyst and may necessitate the application of a soot blower.[13]

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. Exhaust gas temperatures greater than the upper limit will cause the NO_X and ammonia to pass through the catalyst unreacted.[14] The exhaust temperature of the turbines assessed here is approximately 580 °F.

[10] Ibid.
[11] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.
[12] Ibid.
[13] Ibid.
[14] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines"

SCR is considered a technically feasible control option for the turbines located at Pecos River. SCR units typically achieve 65% to 90% NO_X reduction, dependent on the exhaust temperature and upstream NO_X concentration.[15]

[15] Ibid.

EPNG has evaluated the costs of implementing the technically feasible control technologies as thoroughly as possible in the time provided to complete this assessment. These cost estimates are calculated according to the methods and recommendations in the EPA Air Pollution Control Cost Manual.[16] Cost effectiveness considerations for the turbines are discussed below, with costs summarized in Table 3.

Table 3. Cost Analysis Summary of Technically Feasible Control Options for Combustion Turbines

Control Equipment	Unit	SCR Capital Cost ($)	Building Modifications ($)	Total Annual Cost ($)*	Emission Reduction (tpy)	Cost Effectiveness ($/ton)
Selective Catalytic Reduction	A-01	3,802,798	2,500,000	656,640	36.0	18,252
	A-02	3,802,798	2,500,000	664,748	66.9	9,931
	A-03	3,802,798	2,500,000	662,707	61.0	10,858

*Total Annual Cost includes the annualized SCR capital and building modification costs, as well as the direct and indirect annual operating costs.

EPNG has selected to use the EPA Air Pollution Control Cost Spreadsheet for SCR to estimate the costs associated with implementing an SCR control system on the turbines at Pecos River. The estimate incorporates direct capital cost for equipment and vendor labor, direct annual costs (maintenance, operating labor, reagent cost, electricity cost, and catalyst cost), and indirect costs associated with EPNG's internal labor, overhead and capital recovery for the project.

In addition, there are site-specific space limitations that prevent the installation of the necessary equipment for this control method (i.e., SCR module and reagent storage systems). Based on the current configuration of the turbines, the exhaust system ducting would require significant modifications in order to install the catalyst. Specifically, the stack for each unit would need to be relocated and additional ducting would be required. At this time, EPNG believes that there is insufficient room within the existing building that houses the turbines to complete the necessary modifications and installation of the catalyst. The cost necessary to modify the turbine housing has been estimated by EPNG and is accounted for in this cost effectiveness calculation.

This cost estimate assumes that the SCR will reduce NO_X emissions with a 70% efficiency.[17] There is no historical data to support a higher control efficiency assumption. In addition, due to the age of the units and current availability of control equipment for them, it is assumed that there would be significant difficulties retrofitting each of these turbines with an SCR control. Therefore, a retrofit difficulty factor of 1.5 is used for this analysis.

These cost estimates have been developed based on the actual emissions from each unit assessed here, calculated using June 2016 stack test data for each unit and the actual hours of operation from the 2016 Emission Inventory submittal for Pecos River. The stack test data utilized for these calculations is included in Appendix C of this report and a copy of the EPA Air Pollution Control Cost Spreadsheet for each unit is included in Appendix D.

[16] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

[17] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.

4. TIME NECESSARY FOR COMPLIANCE

The second factor in this analysis is the time necessary for compliance. Consideration of this factor involves estimating the time required for a source to implement a potential control measure. This information is provided here in order to advise the NMED of EPNG's projection of a reasonable compliance timeline based on the equipment and site-specific considerations that could affect the time necessary to comply.

EPNG estimates that approximately 36 months will be necessary to make the building modifications and install the SCR control equipment. Factors that have been considered for this anticipated timeline include project development, engineering, lead time to acquire the necessary materials, construction, and commissioning.

5. ENERGY AND NON-AIR ENVIRONMENTAL IMPACTS

This section addresses the potential energy and non-air environmental impacts that installation of the technically feasible control options poses on a source. The consideration of energy impacts involves assessing the impact of a control measure on the energy that is consumed by the source. Non-air environmental impacts are assessed based on the effect of the control on non-air environmental media. Some examples of non-air environmental impacts include water resource depletion, solid waste generation, increased noise and odor pollution, and increased land usage.

The implementation of SCR on the turbines at Pecos River would result in several energy and non-air impacts. The primary impact of this control would be a significant increase in energy consumption, which would be necessary to power the units. The estimated energy consumption for each unit is summarized in Table 4, and is based on the EPA Air Pollution Control Cost Manual.[18] The calculation for these values is included in Appendix E of this report. EPNG does not anticipate any issues with meeting this increased energy burden.

Table 4. Energy Consumption Analysis Summary

Unit	Annual Energy Consumption (MWh)
A-01	158.3
A-02	227.7
A-03	206.6
Total	592.6

In addition to the increased energy burden, there are several non-air environmental impacts associated with the handling and storage of the reagent used in the SCR system, typically ammonia or urea. Ammonia is a Toxic Air Pollutant (TAP) regulated under 20.2.72.502 NMAC with an occupational exposure limit (OEL) of 18 mg/m^3. In both soil and water, urea is hydrolyzed quickly to ammonia and carbon dioxide by urease, an extracellular enzyme that originates from microorganisms and plant roots.[19] Short-term inhalation exposure to high levels of ammonia in humans can cause irritation and serious burns in the mouth, lungs, and eyes. Chronic exposure to airborne ammonia can increase the risk of respiratory irritation, cough, wheezing, tightness in the chest, and impaired lung function in humans. Animal studies also suggest that exposure to high levels of ammonia in air may adversely affect other organs, such as the liver, kidney, and spleen.[20]

Unavoidable releases of ammonia could have significant and irreversible impacts on the living and physical environment affected. Storage and handling of urea or ammonia onsite would result in an increased risk to the health and safety of facility operators. Pecos River is a natural gas compressor station, which already maintains a high level of health and safety risk. EPNG considers any increase to this risk unacceptable.

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[18] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

[19] U.S. EPA, EPA/635/R-10/005F, "Toxilogical Report of Urea", July 2011

[20] U.S. EPA, EPA/635/R-16/163Fc, "Toxicological Review of Ammonia Noncancer Inhalation: Executive Summary", September 2016

6. REMAINING USEFUL LIFE OF SOURCES

The anticipated remaining useful life of each source is addressed here for the NMED's consideration. The assessment of this factor involves estimating how long the sources analyzed will remain in operation and the lifetime of potential control measures, accounting for equipment and site-specific limitations.

40 CFR Part 51, Appendix Y includes guidance on the characterization of this factor, stating that the remaining useful life of a source will typically be longer than the useful life of the emission control system. Therefore, it is appropriate to annualize compliance costs based on the useful life of the control equipment, rather than the life of the source.[21]

Based on their current age and operating efficiency, it is estimated that the remaining useful life of the turbines will be longer than the SCR units. The turbines have operated for more than 65 years without any significant deterioration in operating efficiency; therefore, this analysis of the remaining useful life of the equipment will be based on the anticipated useful life of the SCR control device installed.

The estimated useful life of the SCR equipment is 20 years, based on default values from the EPA Air Pollution Control Cost Manual.[22]

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[21] 40 CFR 51, Appendix Y, Section II.B.4.f

[22] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

Based on a comprehensive review of the RBLC, available literature, and manufacturer's input of the available control technologies for the natural-gas fired turbines located at Pecos River, EPNG has determined that SCR is the only technically feasible control option for these units. The cost of compliance to install SCR controls on each of these units has been estimated based on the EPA Air Pollution Control Cost Manual.[23] The estimated cost effectiveness and NO_X emission reduction for each unit are summarized in Table 5, below.

Table 5. Summary of Cost Effectiveness and NO_X Reduction for SCR Control of the Turbines

Control Equipment	Unit	NO_X Reduction (tpy)	Cost Effectiveness ($/ton)
Selective Catalytic Reduction	A-01	36.0	18,252
	A-02	66.9	9,931
	A-03	61.0	10,858

It is projected that the useful life of these units will be 20 years, based on the life expectancy of the SCR controls. The primary energy and non-air impacts from this control method will be increased energy consumption and health and safety risk. EPNG estimates that 36 months would be an achievable compliance timeline for this control.

[23] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

8. SUPPORTING DOCUMENTATION

Appendix A – RBLC Tables
Appendix B – June 2016 Stack Test Data
Appendix C – Cost Analysis Calculations
Appendix D – Energy Consumption Calculation

APPENDIX A - RBLC TABLES

RBLC Analysis for Natural Gas Fired Turbines – NO_X Control

IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology	Good Combustion Technique	Improved Combustion Technology (Low-NO_X Combustors, Ultra-Low NO_X Combustors and other improved combustion technology)[a]	Water/Steam Injection[b]	Selective Catalytic Reduction (SCR)[c]
	Control Technology Description	NO_x emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. Primary combustion occurs at lower temperatures under oxygen-deficient conditions. By following EPA's "Good Combustion Practices" guidance document, good combustion practices can be 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 optimal NO_x emissions.	Low-NO_x burners employ multi-staged combustion to inhibit the formation of NO_X. Primary combustion occurs at lower temperatures under oxygen-deficient conditions; secondary combustion occurs in the presence of excess air. This category includes Improved Combustion Technology Lean Head End Liners for the GE turbines assessed here.	Injected water/steam acts as a heat sink, lowering combustion zone peak temperatures, resulting in a decrease in thermal NO_X.	A nitrogen-based reagent (e.g., ammonia, urea) is injected into the exhaust stream downstream of the combustion unit. The reagent reacts selectively with NO_X to produce molecular N_2 and water in a reactor vessel containing a metallic or ceramic catalyst.
	Other Considerations	N/A	N/A	Results in a small efficiency penalty but an increase in power output. May increase CO and VOC emissions. Not available in certain models.	Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as "ammonia slip." Unreacted reagent may form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a soot blower.
	RBLC Database Information	Included in RBLC for control of NO_X emissions from combustion turbines.	Included in RBLC for the control of NO_X emissions from combustion turbines.	Not included in RBLC for the control of NO_X emissions from combustion turbines; identified as a control option based on AP-42 Section 3.1.	Included in RBLC for the control of NO_X emissions from combustion turbines.
ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	Feasibility Discussion	Technically feasible.	Technically infeasible. This option is not available for the turbine model.	Technically infeasible. This option is not available for the turbine model.	Technically feasible.
RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency	Base Case			65-90%

a. California EPA, Air Resources Board, "Section 311 - Non-Selective Catalytic Reduction and Other NO_X Controls," http://www.arb.ca.gov/cap/manuals/cntrldev/sncr_etc/311nscr.htm
b. U.S. EPA, AP-42 Section 3.1, "Stationary Gas Turbines"
c. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.

RBLCID	FACILITY NAME	EPA REGION	PERMIT NUM	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	PROCESS NOTES	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	COST EFFECTIVENESS	INCREMENTAL COST EFFECTIVENESS	Cost Verified	DOLLAR YEAR USED IN COST ESTIMATES
AK-0083	KENAI NITROGEN OPERATIONS	10	AQ0083CPT06	Five (5) Natural Gas Fired Combustion Turbines	16.11	Natural Gas	37.6	MMBTU/H	Five (5) Natural Gas-Fired Solar Combustion Turbines rated at 37.6 MMBtu/hr each. Installed in 1976.	Nitrogen Oxides (NOx)	A	Selective Catalytic Reduction	0			0	0	N	
CA-1215	QUALCOMM INC.	9	2012--APP-002100	Cogeneration gas turbine	16.11	natural gas	4.37	MW	Manufacturer: Solar Turbines- Model: Mercury 50-6400R	Nitrogen Oxides (NOx)	A	SoLoNOx burner (Ultra lean Premix)	0			0	0	N	
LA-0331	CALCASIEU PASS LNG PROJECT	6	PDS-LA-805	Aeroderivative Simple Cycle Combustion Turbine	16.11	Natural Gas	263	MM BTU/h		Nitrogen Oxides (NOx)	B	Selective Catalytic Reduction (SCR), exclusive combustion of fuel gas, and good combustion practices.	0			0	0	N	
MI-0410	THETFORD GENERATING STATION	5	191-12	FG-PEAKERS: 2 natural gas fired simple cycle combustion turbines	16.11	natural gas	171	MMBTU/H	Two natural gas fired simple cycle combustion turbines each with an electrical generator (nominal 13MW each; 171 MMBtu/hr heat input rating each). Each turbine is limited to 343 MMscf of natural gas per 12-month rolling time period as determined at the end of each calendar month. Both turbines combined are limited to 5.15 MMscf of natural gas each calendar day.	Nitrogen Oxides (NOx)	P	Dry low-NOx combustors	0			0	0	N	
MI-0420	DTE GAS COMPANY--MILFORD COMPRESSOR STATION	5	185-15	FG-TURBINES	16.11	Natural gas	10504	HP	Five (5) simple cycle natural gas-fired combustion turbines (CTs) to drive compressors that will be used to transport natural gas through pipelines. The turbines are identified as EUTURBINE1, EUTURBINE2, EUTURBINE3, EUTURBINE4, and EUTURBINE5 within the flexible group FGTURBINES. There shall be no more than a combined total of 5 events (startup or shutdown) per clock hour. The total number of startup events for all units combined shall not exceed 500 events per 12-month rolling time period. The total number of shutdown events for all units combined shall not exceed 500 events per 12-month rolling time period. The maximum nominal rating of each turbine shall not exceed 10,504 HP (ISO).	Nitrogen Oxides (NOx)	A	Dry ultra-low NOx burners	0			0	0	N	
MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	5	185-15A	FGTURNBINES (5 Simple Cycle CTs: EUTURBINE1, EUTURBINE2, EUTURBINE3, EUTURBINE4, EUTURBINE5)	16.11	Natural gas	10504	HP	Five simple cycle natural gas-fired combustion turbines (CTs) to drive compressors that will be used to transport natural gas through pipelines (EUTURBINE1, EUTURBINE2, EUTURBINE3, EUTURBINE4, EUTURBINE5 in FGTURBINES). There shall be no more than a combined total of 5 events (startup or shutdown) per clock hour. The total number of startup events for all units combined shall not exceed 500 events per 12-month rolling time period. The total number of shutdown events for all units combined shall not exceed 500 events per 12-month rolling time period. The maximum nominal rating of each turbine shall not exceed 10,504 HP (ISO).	Nitrogen Oxides (NOx)	A	Dry ultra-low NOx burners.	0			0	0	N	
NV-0050	MGM MIRAGE	9	825	TURBINE GENERATORS - UNITS CC007 AND CC008 AT CITY CENTER	16.11	NATURAL GAS	4.6	MMBTU/H	THE TWO UNITS ARE IDENTICAL SOLAR MERCURY COMBUSTION GAS TURBINES FOR ELECTRIC POWER GENERATION. EACH UNIT IS RATED AT 4.6 MMBTU/HR, AND IS ALLOWED TO OPERATE 24 HOURS/DAY AND 8,760 HOURS/YEAR.	Nitrogen Oxides (NOx)	P	LEAN PRE-MIX TECHNOLOGY AND LIMITING THE FUEL TO NATURAL GAS ONLY	0.178	LB/MMBTU		0	0	N	
OK-0148	BUFFALO CREEK PROCESSING PLANT	6	2012-1026-C PSD	Small Combustion Turbines (<25MW)	16.11	Natural Gas	10179	Horsepower	Solar Taurus 70-10802S times 2.	Nitrogen Oxides (NOx)	P	Dry-Low NOx Combustion	0			0	0	N	
OK-0153	ROSE VALLEY PLANT	6	2012-1393-C PSD	TURBINES 9,443-HP SIEMENS SGT-200-2S	16.11	NATURAL GAS	9443	HP	THERE ARE TO BE LIKE-KIND TURBINES	Nitrogen Oxides (NOx)	P	DRY LOW-NOx COMBUSTION.	0			0	0	N	
*PA-0314	BEECH HOLLOW	3	63-00922D	COMBUSTION TURBINE without DUCT BURNERS UNIT	16.11	Natural Gas	2433	MMBtu/hr	CEMS for NOx, CO	Nitrogen Oxides (NOx)	A	SCR	0			0	0	N	
TX-0642	SINTON COMPRESSOR STATION	6	PSDTX1304	Compression Turbine	16.11	natural gas	20000	hp	Two (2) 20,000 horsepower Solar Titan 130S turbines in natural gas pipeline compression service	Nitrogen Oxides (NOx)	P	Solar's SoLoNOx dry emission control technology	0			0	0	N	
TX-0685	GUADALUPE GENERATING STATION	6	106011 PSDTX1310	(2) simple cycle turbines	16.11	natural gas	190	MW	Four models are approved: GE7FA.03, GE7FA.04, GE7FA.05, or Siemens SW 5000F5. 383 MW to 454 MW total plant capacity.	Nitrogen Oxides (NOx)	B	DLN burners, limited operation	0			0	0	N	
*WI-0283	AFE, INC. â€"LCM PLANT	5	17-JJW-207	P90 â€" Natural Gas-Fired Emergency Generator	16.11	Natural Gas	9.51	mmBTU/hr	750 kW or 1,114 brake horsepower	Nitrogen Oxides (NOx)	P	Good Combustion Practices and the Use of Turbocharger and Aftercooler	0			0	0	N	
WY-0067	ECHO SPRINGS GAS PLANT	8	MD-7837	TURBINES S35-S36	16.11	NATURAL GAS	12555	HP	TWO (2) 12,555 HP SOLAR MARS 100-15000S TURBINES	Nitrogen Oxides (NOx)	N	SOLONOX	0			0	0	N	
WY-0067	ECHO SPRINGS GAS PLANT	8	MD-7837	TURBINE S34	16.11	NATURAL GAS	3856	HP	SOLAR CENTAUR 40-T4700S	Nitrogen Oxides (NOx)	N	SOLONOX	0			0	0	N	

APPENDIX B - EPNG TURBINE BEST PRACTICES PROCEDURES

Table of Contents

1. Scope

1.1. General

Historically, some "Best Practices" documents were developed to cover specific regions, pipelines, or other limited-scope situations. While such documents may not agree with all provisions of Company Operating and Maintenance (O&M) Procedures, they contain vital information and considerations that may prove useful to many users.

Best Practices documents are intended to *complement* Company O&M Procedures. As such, this procedure provides *recommendations* and *guidance* to supplement the Company and Code Requirements defined within O&M Procedures, Engineering Standards, and other Company Compliance Documents.

In all applications, Company O&M Procedures and Engineering Standards shall prevail as Company Requirements.

1.2. G.E. Gas Turbine Inspection/Maintenance Schedules

Regular analysis, inspection, and maintenance of G.E. gas turbines contribute to a reliable, efficient, and safe operation of the Company turbine fleet.

2. Recommendations

G.E. gas turbines should be maintained following the maintenance programs set forth below. These are minimum recommendations and should be adjusted for each location as operating conditions warrant.

A) Typically, the life-limiting components are in the hot section. Parameters affecting the schedules for inspection and repair or replacements are material erosion, including oxidation and corrosion, stress rupture, and fatigue. Each engine component will have different critical limits and may react differently to specific environments and/or deviation from the basic design condition. Therefore, each location should monitor the condition of their unit and take necessary actions to ensure a safe and reliable operation.

B) It is recommended that a start counter be installed on each unit and all full load trips be logged in order to ensure applicable maintenance scheduling. Repeated starts and trips from full load impose large thermal stresses on parts leading to an increased potential for Low Cycle Fatigue (LCF) failure. These high thermal stresses are common in most gas turbine materials because the alloying elements used to achieve material strength at high temperatures are the same ones that produce low thermal conductivity. Thus, it is important to account for all starts and trips on all units.

   Anything that can be done to reduce trips at full load will reduce the potential for component failures resulting from low cycle fatigue.

3. Procedure

A) General Electric Frame 3 and Frame 5 Turbines

   1) Every 800-1,200 Fired Hours Operated

      a. Take lube oil sample for laboratory analysis.

b. Check oil level in the oil sump. Verify that no oil is present in the skid sump vent line.

2) Every 8,000 Fired Hours Operated

   a. Check controls and recalibrate if necessary.
   b. Calibrate recycle valve positioner and ensure valve operates at required speed.

3) 8,000-11,000 E.H.O.* - Combustor Inspection

   *For GE Frame 3 Turbines: E.H.O. = hours operated + (# of starts x 10) + (# of full load trips x 100) (A full load trip is any trip of the turbine when operating above 75% load.)

   Combustor inspection should include:

   a. Boroscope of blading, buckets, and nozzles
   b. Inspection of the combustion liners
   c. Inspection of the cowl caps
   d. Inspection of the transition pieces
   e. Inspection of the Axial Flow Compressor (AFC) and stator blading including the washing
   f. Removal of fuel nozzles for cleaning and inspection for cracks/other defects
   g. Check of igniters and flame detectors
   h. Greasing all the auxiliary couplings
   i. Repair of any maintenance items required
   j. Inspect all tubing, hoses, and fittings.

4) 26,000-28,000 E.H.O.* - Hot Gas Path Inspection

   *For GE Frame 3 Turbines: E.H.O. = hours operated + (# of starts x 10) + (# of full load trips x 100) (A full load trip is any trip of the turbine when operating above 75% load.)

   Hot gas path inspection should include:

   a. Inspection of the combustion liners
   b. Inspection of the cowl caps
   c. Inspection of the transition pieces
   d. Inspection of the Axial Flow Compressor (AFC) and stator blading including the washing
   e. Removal of the shell half
   f. Inspection of the first stage nozzles
   g. Check alignment from the turbine to compressor.
   h. Grease all the auxiliary couplings.
   i. Repair any maintenance items required.
   j. The turbine should be cleaned and inspected for cracks, chips, hot spots, or other damage.
   k. Damaged or defective parts will be repaired or replaced, as required.

5) Overhaul - 38,000 - 42,000 E.H.O. for units with composite wheels,

   Overhaul - 48,000 - 50,000 E.H.O. for units with non-composite wheels.

   Each Overhaul should include:

   a. Inspection of the combustion liners
   b. Inspection of the cowl caps
   c. Inspection of the transition pieces
   d. Inspection of the Axial Flow Compressor (AFC) and stator blading including the washing
   e. Removal of the shell half
   f. Inspection of the First stage nozzles
   g. Removal of all the rotating assemblies
   h. Inspection of the accessory gear section
   i. Inspection of the load coupling
   j. Grease all the auxiliary couplings.
   k. Inspection of the Second Stage nozzles

l. Inspection of the starting means
m. Inspection of the high-speed coupling
n. Removal and inspection of the air and oil seals
o. Removal and inspection of all the bearings
p. Check alignment from the turbine to compressor.
q. Bump check compressor.
r. Calibrate all logic controls at major overhaul.

B) GE LM500 TURBINES

1) Weekly -

a. Check oil levels.
b. Check oil pressure.
c. Check engine air pressure (P-3).
d. Check for leaks (air, oil, etc.).
e. Check for signs of hot spots on case.
f. Check for excessive noises or vibrations.
g. Check air and oil filter differentials.
h. Check for loose bolts, fittings, etc.
i. Check control gauges and transmitters for leaks.

2) Every 1,000 - 1,200 Hours Operated -

a. Conduct a thorough visual inspection of outer parts.
b. Take lube oil sample for laboratory analysis.
c. Check fuel and start gas lines for leaks.
d. Change oil filters with high differential pressure.
e. Change air inlet pre-filters if oily.
f. Check package air inlet filters.
g. Check V.G. control cable for wear or slack.
h. Check lock-wires on bolts and nuts for breaks.
i. Check chip detectors in lube oil lines.

3) Every 7,000-8,000 Fired Hours Operated -

a. Boroscope hot and cold ends and gas compressor.
b. Pull fuel nozzles and check for wear.
c. Pull and inspect half of low pressure power turbine case.

4) Annual not to exceed 15 months -

a. Check calibrations on all transmitters.
b. Check calibrations on controls (speed, EGT, P-3, etc.).
c. Check calibrations on Woodward governor fuel slopes.
d. Check calibration of vibration and shutdown devices.
e. Check and test all safety shutdowns.
f. Calibrate recycle valve positioner and ensure valve operates at required speed.

5) Overhauls on LM500 turbines are to be conducted as needed, based on Boroscope inspections.

a. Calibrate all logic controls at major overhaul.

4. Documentation

Some Pipelines and related Field Staff use one or more of the following:

- MAXIMO as an activities scheduling utility
- COMET for Compressor Data tracking

- Other Legacy Forms and Data Logs

Until such time as these systems (MAXIMO, COMET, etc.) are superseded, the following information is provided for user reference:

MAXIMO PM

- GE Frame 3 & Frame 5 - Oil Analysis - Every 2 months NTE 75 days or 1200 Fired Operated Hours
- GE Frame 3 & Frame 5 – Controls Calibration
- GE Frame 3 & Frame 5 - Combustor Inspection - 8000 NTE 11,000 E.H.O.
- GE Frame 3 & Frame 5 - Hot Gas Path Inspection - 26,000 NTE 28,000 E.H.O.
- GE Frame 3 & Fame 5 - Major Overhaul (Composite Turbine Wheels) - 38,000 NTE 42,000 E.H.O.
- GE Frame 3 & Frame 5 - Major Overhaul (Non-Composite Turbine Wheels) - 48,000 NTE 50,000 E.H.O.
- GE LM500 - Weekly Inspection - Weekly
- GE LM500 - 1,000 Hour Inspection - 1,000 NTE 1,200 Fired Hours Operated
- GE LM500 - 7000 Hour Inspection - 7000 NTE 8000 Fired Hours Operated
- GE LM500 - Controls Calibration - 1 Year NTE 15 Months

Engine Oil Analysis Report - Vendor Form (Refer to **Best Practices COMP203-3 - Turbine Oil Analysis**)

- Retention - 1 Year Plus Current Year
- Retention Location - Station

Protective Device Check Gas Turbines – (COMP-0178)

- Retention – 1 Year Plus Current Year
- Retention Location - Station

Turbine Inspection Forms Workbook (Frame & Model Specific) - (COMP-2008 through COMP-2018), OR:
GE Combustion Liner Inspection Report - Vendor Form
GE Hot Gas Path Inspection Report - Vendor Form
GE Major Overhaul Inspection Report - Vendor Form

- Retention - Life of the Equipment
- Retention Location, Turbine Inspection Forms Workbook – Livelink
- Retention Location, G.E. Vendor Forms - Station

5. References

- **Best Practices COMP202-6 - Turbine Filter Replacement**
- **Best Practices COMP203-1 - Turbine Maintenance Analysis**
- **Best Practices COMP203-3 - Turbine Oil Analysis**
- **Best Practices COMP204-1 - Unit Protective Device Check - Turbine Engines**
- **Environmental, Health, and Safety Policy Manual**
- **O&M Procedures Manual**

APPENDIX C – JUNE 2016 STACK TEST DATA

SUMMARY OF TEST RESULTS PECOS RIVER STATION

Permit P129R2M1 – October 4, 2011

Pecos River Station unit S001 GE Model M3712R A S/N95025

Annual performance testing was performed on unit 1 exhaust for NOx, CO, and O2 on July 12, 2016. Maximum achievable load compliance consisted of three (20) twenty minute sampling events which were used to calculate the average for the emission values. These averages were then compared with the unit permitted limits to determine the performance status. **Based on the test results, unit S001 PASSED the Performance Test Audit**

Parameter	Measured	Permit	Status
Emission Load (% HP)	94.09	n/a	n/a
NOx (lb/hr)	20.63	53.10	PASS
NOx (TPY)	89.79	233	PASS
CO (lb/hr)	4.36	8.00	PASS
CO (TPY)	19.00	35	PASS

SUMMARY OF TEST RESULTS PECOS RIVER STATION

Permit P129R2M1 – October 4, 2011

Pecos River Station unit S002 GE Model M3712R A S/N95053

Annual performance testing was performed on unit 2 exhaust for NOx, CO, and O2 on June 21, 2016. Maximum achievable load compliance consisted of three (20) twenty minute sampling events which were used to calculate the average for the emission values. These averages were then compared with the unit permitted limits to determine the performance status. **Based on the test results, unit S002 PASSED the Performance Test Audit**

Parameter	Measured	Permit	Status
Emission Load (% HP)	105.62	n/a	n/a
NOx (lb/hr)	26.69	53.10	PASS
NOx (TPY)	116.21	233	PASS
CO (lb/hr)	3.67	8.00	PASS
CO (TPY)	15.97	35	PASS

SUMMARY OF TEST RESULTS PECOS RIVER STATION

Permit P129R2M1 – October 4, 2011

Pecos River Station unit S003 GE Model M3712R A S/N95055

Quarterly performance testing was performed on unit 3 exhaust for NOx, CO, and O2 on June 21, 2016. Maximum achievable load compliance consisted of three (20) twenty minute sampling events which were used to calculate the average for the emission values. These averages were then compared with the unit permitted limits to determine the performance status. **Based on the test results, unit S003 PASSED the Performance Test Audit**

Parameter	Measured	Permit	Status
Emission Load (% HP)	91.00	n/a	n/a
NOx (lb/hr)	26.82	53.10	PASS
NOx (TPY)	116.80	233	PASS
CO (lb/hr)	4.11	8.00	PASS
CO (TPY)	17.87	35	PASS

APPENDIX D – COST ANALYSIS CALCULATIONS

El Paso Natural Gas Company, LLC

Pecos River Compressor Station

Turbine Cost Analysis	Interest Rate:	5.50%
All Units	Period (yrs):	20

Control Equipment	Unit	SCR Capital Cost	Building Modification	Total Annual Cost*	Emission Reduction	Cost Effectiveness
		($)	($)	($)	(tpy)	($/ton)
Selective Catalytic Reduction (SCR)	A-01	3,802,798	2,500,000	656,640	36.0	18,252
	A-02	3,802,798	2,500,000	664,748	66.9	9,931
	A-03	3,802,798	2,500,000	662,707	61.0	10,858

* Total Annual Cost includes the annualized capital cost as well as the direct and indirect annual operating costs.

El Paso Natural Gas Company, LLC

Pecos River Compressor Station

GE Model M3712R Turbine	Interest Rate:	5.50%	
A-01	Period (yrs):	20	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_X lb/hr:		20.63 lb/hr	<-- June 2016 stack test results
NO_X tpy:		51.39 tpy	<-- Calculated using 2016 stack test and 2016 EI actual operating hours.
SCR			
NO_X Reduction:		70%	<-- Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032
NO_X lb/hr:		6.19 lb/hr	
NO_X tpy:		15.42 tpy	
Turbine Housing Reconfiguration	$	2,500,000	<-- Estimated cost from EPNG
SCR Capital Investment	$	3,802,798	<-- EPA Cost Control Spreadsheet
Total Capital Investment	$	6,302,798	
Annualized TCI:	$	527,414	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	129,227	<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	656,640	
Emissions Reduction:		36.0 tpy	
Cost Effectiveness:	**$**	**18,252.11 $/ton**	

Unit A-01: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new turbine or retrofit of an existing turbine?

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?[1]	61.8 MMBtu/hour
What is the higher heating value (HHV) of the fuel?[1,2]	1,031 Btu/scf
What is the estimated actual annual fuel consumption?	298,551,855 scf/Year
Enter the net plant heat input rate (NPHR)	8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 2900 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the Cost Estimate tab. Please select your preferred method:

- Method 1
- Method 2
- Not applicable

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.
[2] Fuel consumption adjusted for actual 2016 operating hours, per the 2016 Emission Inventory submittal (524.9 MMscf/yr * 4982.50/8760 hours/year = 298.55 MMscf/yr)

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365 days
Number of days the turbine operates (tplant)	365 days
Inlet NO_x Emissions (NOx_{in}) to SCR[2]	0.3338 lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR[3]	0.1001 lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1
Number of catalyst layers (R_{layer})	3
Number of empty catalyst layers (R_{empty})	1
Ammonia Slip (Slip) provided by vendor	2 ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours
Estimated SCR equipment life	20 Years*

* For industrial turbines, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650 ^{o}F
Base case fuel gas volumetric flow rate factor (Q_{fuel})[4]	35103.70 ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29 percent*
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14 days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.
[2] Permitted NO_x emission rate / permitted heat input (53.1 lb/hr / 61.8 Mmbtu/hr)
[3] Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032; 70% efficiency
[4] Calculated based on the estimated actual annual fuel consumption and maximum heat input rate.

Enter the cost data for the proposed SCR:

Desired dollar-year	2018	
CEPCI for 2018	603.1 Enter the CEPCI value for 2018 — 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5 Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293 $/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0676 $/kWh	* $0.0676/kWh is a default value for electricity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 $/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

Unit A-01: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	61.8	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	525,090,204	scf/Year	
Actual Annual fuel consumption (Mactual) =		298,551,855	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.569	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4981	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	70.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	14.44	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	35.96	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.88		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	2,075,900	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	9,383.94	/hour	
Residence Time	$1/V_{space}$	0.00	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired turbines
Elevation Factor (ELEVF) =	14.7 psia/P =	1.11		
Atmospheric pressure at sea level (P) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)*$ =	13.2	psia	
Retrofit Factor (RF)	Retrofit to existing turbine	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	221.22	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	2,162	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	2,487	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	49.9	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	41	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	6	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	19	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	900	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial turbines.	31.78	kW

Unit A-01: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Turbines

For Oil and Natural Gas-Fired Utility turbines between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility turbines >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial turbines between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial turbines between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial turbines >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial turbines >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$3,802,798	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$126,370 in 2018 dollars
Indirect Annual Costs (IDAC) =	$321,150 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$447,521 in 2018 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$19,014 in 2018 dollars
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600 in 2018 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$3,773 in 2018 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$10,699 in 2018 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$5,284 in 2018 dollars
Direct Annual Cost =		$126,370 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,856 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$318,294 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$321,150 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$447,521 per year in 2018 dollars
NOx Removed =	36.0 tons/year

El Paso Natural Gas Company, LLC

Pecos River Compressor Station

GE Model M3712R Turbine	Interest Rate:	5.50%	
A-02	Period (yrs):	20	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_X lb/hr:	26.69 lb/hr		<-- June 2016 stack test results
NO_X tpy:	95.62 tpy		<-- Calculated using 2016 stack test and 2016 EI actual operating hours.
SCR			
NO_X Reduction:	70%		<-- Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032
NO_X lb/hr:	8.01 lb/hr		
NO_X tpy:	28.69 tpy		
Turbine Housing Reconfiguration	$ 2,500,000		<-- Estimated cost from EPNG
SCR Capital Investment	$ 3,802,798		<-- EPA Cost Control Spreadsheet
Total Capital Investment	$ 6,302,798		
Annualized TCI:	$ 527,414		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$ 137,334		<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$ 664,748		
Emissions Reduction:	66.9 tpy		
Cost Effectiveness:	**$ 9,931.02 $/ton**		

Unit A-02: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new turbine or retrofit of an existing turbine?

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?[1]	61.8	MMBtu/hour
What is the higher heating value (HHV) of the fuel?[1,2]	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	429,357,414	scf/Year
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 2900 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the Cost Estimate tab. Please select your preferred method:

- Method 1
- Method 2
- Not applicable

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.
[2] Fuel consumption adjusted for actual 2016 operating hours, per the 2016 Emission Inventory submittal (524.9 MMscf/yr * 7165.5/8760 hours/year = 429.3 MMscf/yr)

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the turbine operates (tplant)	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR[2]	0.4319	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR[3]	0.1296	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial turbines, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})[4]	50483.81	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.
[2] Permitted NO_x emission rate / permitted heat input (53.1 lb/hr / 61.8 Mmbtu/hr)
[3] Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032; 70% efficiency
[4] Calculated based on the estimated actual annual fuel consumption and maximum heat input rate.

Enter the cost data for the proposed SCR:

Desired dollar-year	2018		
CEPCI for 2018	603.1	Enter the CEPCI value for 2018 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0676	$/kWh	* $0.0676/kWh is a default value for electricity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

Unit A-02: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	62	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	525,090,204	scf/Year	
Actual Annual fuel consumption (Mactual) =		429,357,414	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.818	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	7163	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	70.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	18.68	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	66.91	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.88		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	2,985,421	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	13,066.96	/hour	
Residence Time	1/V_{space}	0.00	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired turbines
Elevation Factor (ELEVF) =	14.7 psia/P =	1.11		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.2	psia	
Retrofit Factor (RF)	Retrofit to existing turbine	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	228.47	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	3,110	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	3,576	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	59.8	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	41	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	7	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	25	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,200	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n$/$(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial turbines.	31.78	kW

Unit A-02: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Turbines

For Oil and Natural Gas-Fired Utility turbines between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility turbines >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial turbines between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial turbines between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial turbines >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial turbines >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$3,802,798	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$134,478	in 2018 dollars
Indirect Annual Costs (IDAC) =	$321,150	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$455,628	in 2018 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$19,014	in 2018 dollars
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600	in 2018 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$7,019	in 2018 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$15,387	in 2018 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$5,458	in 2018 dollars
Direct Annual Cost =		$134,478	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,856	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$318,294	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$321,150	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$455,628	per year in 2018 dollars
NOx Removed =	66.9	tons/year
Cost Effectiveness =	$6,809.34	per ton of NOx removed in 2018 dollars

El Paso Natural Gas Company, LLC
Pecos River Compressor Station

GE Model M3712R Turbine	Interest Rate:	5.50%	
A-03	Period (yrs):	20	<-- EPA Air Pollution Control Cost Manual
Base Case			
NO_X lb/hr:		26.82 lb/hr	<-- June 2016 stack test results
NO_X tpy:		87.19 tpy	<-- Calculated using 2016 stack test and 2016 EI actual operating hours.
SCR			
NO_X Reduction:		70%	<-- Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032
NO_X lb/hr:		8.05 lb/hr	
NO_X tpy:		26.16 tpy	
Turbine Housing Reconfiguration	$	2,500,000	<-- Estimated cost from EPNG
SCR Capital Investment	$	3,802,798	<-- EPA Cost Control Spreadsheet
Total Capital Investment	$	6,302,798	
Annualized TCI:	$	527,414	<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	135,293	<-- EPA Cost Control Spreadsheet
Total Annual Costs:	$	662,707	
Emissions Reduction:		61.0 tpy	
Cost Effectiveness:	**$**	**10,858.37 $/ton**	

Unit A-03: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new turbine or retrofit of an existing turbine?

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?[1]	61.8	MMBtu/hour
What is the higher heating value (HHV) of the fuel?[1,2]	1,031	Btu/scf
What is the estimated actual annual fuel consumption?	389,585,454	scf/Year
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 2900 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the Cost Estimate tab. Please select your preferred method:

- Method 1
- Method 2
- Not applicable

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.
[2] Fuel consumption adjusted for actual 2016 operating hours, per the 2016 Emission Inventory submittal (524.9 MMscf/yr * 6501.75/8760 hours/year = 389.6 MMscf/yr)

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the turbine operates (tplant)	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR[2]	0.4340	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR[3]	0.1302	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial turbines, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	^{o}F
Base case fuel gas volumetric flow rate factor (Q_{fuel})[4]	45807.42	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used

NOTES: [1] Data referenced from the most recent Title V application for P129-R3M1.
[2] Permitted NO_x emission rate / permitted heat input (53.1 lb/hr / 61.8 Mmbtu/hr)
[3] Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032; 70% efficiency
[4] Calculated based on the estimated actual annual fuel consumption and maximum heat input rate.

Enter the cost data for the proposed SCR:

Desired dollar-year	2018		
CEPCI for 2018	603.1	Enter the CEPCI value for 2018 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0676	$/kWh	* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

Unit A-03: SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	62	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	525,090,204	scf/Year	
Actual Annual fuel consumption (Mactual) =		389,585,454	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.742	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	6499	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	70.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	18.77	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	61.01	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.88		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	2,708,877	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	11,848.48	/hour	
Residence Time	1/V_{space}	0.00	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired turbines
Elevation Factor (ELEVF) =	14.7 psia/P =	1.11		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.2	psia	
Retrofit Factor (RF)	Retrofit to existing turbine	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	228.63	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	2,822	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	3,245	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	57.0	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	41	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	7	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	25	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,200	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial turbines.	31.78	kW

Unit A-03: Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Turbines

For Oil and Natural Gas-Fired Utility turbines between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility turbines >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial turbines between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial turbines between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial turbines >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial turbines >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$3,802,798	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$132,437 in 2018 dollars
Indirect Annual Costs (IDAC) =	$321,150 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$453,588 in 2018 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$19,014 in 2018 dollars
Annual Operating Labor Cost =	Operator Labor Rate x Operator Hours/Day x Operating Days/Year =	$87,600 in 2018 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$6,400 in 2018 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$13,962 in 2018 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$5,461 in 2018 dollars
Direct Annual Cost =		$132,437 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,856 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$318,294 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$321,150 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$453,588 per year in 2018 dollars
NOx Removed =	61.0 tons/year

APPENDIX E – ENERGY CONSUMPTION CALCULATION

SCR Energy Usage Calculation
Unit: A-01

Equation:	Electricity Consumption, kW =	$A \times 1{,}000 \times 0.0056 \times (CoalF \times HRF)^{0.43}$		Source: EPA Cost Spreadsheet
Where:	A =	0.1 x QB		EPA Cost Spreadsheet for industrial turbines
	QB =	61.8	MMBTU/hr	Maximum Annual Heat Input Rate
	CoalF =	1.0		EPA Cost Spreadsheet value for Oil and Natural Gas
	Heat Rate Factor (HRF) =	NPHR / 10		
	Net Plant Heat Input Rate (NPHR) =	8.2	MMBtu/MW	Default EPA Cost spreadsheet value
Calculation:	HRF =	0.82		
	A =	6.18		
	Unit A-01 2016 Operating hours =	4982.5	hours	2016 EI Submittal
	Electricity Consumption =	31.8	kW	
	Annual Electricity Consumption =	158.3	MWh/yr	

SCR Energy Usage Calculation
Unit: A-02

Equation:	Electricity Consumption, kW =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$		Source: EPA Cost Spreadsheet
Where:	A =	0.1 x QB		EPA Cost Spreadsheet for industrial turbines
	QB =	61.8	MMBTU/hr	Maximum Annual Heat Input Rate
	CoalF =	1.0		EPA Cost Spreadsheet value for Oil and Natural Gas
	Heat Rate Factor (HRF) =	NPHR / 10		
	Net Plant Heat Input Rate (NPHR) =	8.2	MMBtu/MW	Default EPA Cost spreadsheet value
Calculation:	HRF =	0.82		
	A =	6.18		
	Unit A-02 2016 Operating hours =	7165.5	hours	2016 EI Submittal
	Electricity Consumption =	31.8	kW	
	Annual Electricity Consumption =	227.7	MWh/yr	

SCR Energy Usage Calculation

Unit: A-03

Equation:	Electricity Consumption, kW = $A \times 1{,}000 \times 0.0056 \times (CoalF \times HRF)^{0.43}$		Source: EPA Cost Spreadsheet
Where:	A =	0.1 x QB	EPA Cost Spreadsheet for industrial turbines
	QB =	61.8 MMBTU/hr	Maximum Annual Heat Input Rate
	CoalF =	1.0	EPA Cost Spreadsheet value for Oil and Natural Gas
	Heat Rate Factor (HRF) =	NPHR / 10	
	Net Plant Heat Input Rate (NPHR) =	8.2 MMBtu/MW	Default EPA Cost spreadsheet value
Calculation:	HRF =	0.82	
	A =	6.18	
	Unit A-03 2016 Operating hours =	6501.75 hours	2016 EI Submittal
	Electricity Consumption =	31.8 kW	
	Annual Electricity Consumption =	206.6 MWh/yr	