1. Reasonable Progress Analysis for Nitrogen Oxide Pollution Control Upgrades at San Juan Generating Station Units 1 and 4 and at Escalante Generating Station, Victoria R.Stamper December 19, 2019; Prepared for National Parks Conservation Association and Sierra Club.

2. Oil and Gas Sector Reasonable Progress Four-Factor Analysis of Controls For Five Source Categories: Natural gas-fired Engines, Natural Gas-fired Turbines, Diesel Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration; prepared for National Parks Conservation Association by Vicki Stamper and Megan Williams, March 6, 2020.

3. Letter to NMED staff and memo "Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines May 21, 2020 By Victoria Stamper and Megan Williams.

4. Assessment of Cost Effectiveness Analyses for Controls Evaluated Four – Factor Analyses for Oil and Gas Facilities for the New Mexico Environment Department's Regional Haze Plan for the Second Implementation Period, July 2, 2020, Prepared for National Parks Conservation Organization, Vicki Stamper & Megan Williams.

Reasonable Progress Analysis for Nitrogen Oxide Pollution Control Upgrades at San Juan Generating Station Units 1 and 4 and at Escalante Generating Station

By Victoria R. Stamper

December 19, 2019

Prepared for
National Parks Conservation Association and Sierra Club

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INTRODUCTION AND KEY FINDINGS

The Clean Air Act's regional haze provisions require states to adopt periodic, comprehensive revisions to their implementation plans for regional haze to achieve reasonable progress towards the national visibility goal. The next plan revision for the second implementation period must be submitted to EPA by July 31, 2021.[1] As part of the comprehensive revisions to their regional haze plan**s**, states must submit a long-term strategy that includes enforceable measures that are necessary to make reasonable progress.[2]

This report provides an evaluation of reasonable progress measures for the addition of nitrogen oxide (NOx) controls at three coal-fired electrical generating units (EGUs) in New Mexico – San Juan Units 1 and 4 and the Escalante Generating Station.[3] The New Mexico Environment Department (NMED) has included these EGUs in its list of facilities for which a four-factor analysis of controls is required under the 2016 regional haze rule. This report focuses only on post-combustion pollution controls to reduce NOx emissions – namely selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR). Both SNCR and SCR are commonly implemented control measures for coal-fired EGUs. San Juan Units 1 and 4 began using SNCR to reduce NOx emissions in approximately 2016. Escalante Generating Station is not utilizing either SNCR or SCR. NOx emissions contribute to visibility impairment, as NOx emissions react with water droplets and/or ammonia in the atmosphere to form nitrate particles.

This report concludes that, using a 30-year remaining useful life, the costs to install SCR to meet an annual average NOx emission rate of 0.04 lb/MMBtu are cost effective at San Juan Units 1 and 4 and at Escalante. As is discussed in the report, EPA assumes a 30-year life for evaluating cost effectiveness of SCR systems at coal-fired EGUs, except when there are enforceable limits on the remaining useful life of the EGU of less than 30 years. If a shorter remaining useful life is mandated for the San Juan or Escalante coal-fired EGUs by the New Mexico Energy Transition Act, the cost effectiveness for SCR at Escalante with be about 7% higher (assuming a 25-year life) and the cost effectiveness of SCR at San Juan Units 1 and 4 would be about 18% higher (assuming a 20-year life). These SCR costs are summarized below.

Unit	Total Capital Investment for SCR, 2018$	Direct Annual SCR Operating Costs, 2018$	NOx Reductions, tons per year	Cost Effectiveness of SCR, 30-Year Life	Cost Effectiveness of SCR, (25-Years @ Escalante or 20-Years @ San Juan)
Escalante	$122,479,869	$1,402,894	2,055 tpy	$4,788/ton	$5,128/ton
San Juan Unit 1	$147,040,822	$1,886,195	2,780 tpy	$4,321/ton	$5,109/ton
San Juan Unit 4	$220,700,803	$2,790,097	4,683 tpy	$3,842/ton	$4,544/ton

Requiring SCR at all three units would reduce NOx emissions by nearly 10,000 tons per year.

[1] 40 C.F.R. §51.308(f).
[2] 40 C.F.R. §51.308(f)(2)(i).
[3] This report was prepared by Victoria R. Stamper, an independent air quality consultant and engineer with 28 years of Clean Air Act implementation experience. Ms. Stamper's Curriculum Vitae is included at Exhibit A.

SNCR at Escalante is also cost effective at $3,389/ton and would reduce NOx by about 600 tons per year. However, SCR would remove about 65-75% more NOx than achieved with SNCR.

I. Evaluation of Add-On NOx Controls at New Mexico EGUs to Achieve Reasonable Progress Towards the National Visibility Goal for New Mexico's Regional Haze Plan for the Second Planning Period.

This report provides information on the cost effectiveness of installing post-combustion NOx controls at three EGUs for NMED to take into account in evaluating measures to achieve reasonable progress towards the national visibility goal. There are four factors that must be considered in determining appropriate emissions controls for the second implementation period: 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 source being evaluated for controls.[4] EPA's August 20, 2019 guidance for regional haze plans for the second implementation period indicates that EPA anticipates the cost of controls being the predominant factor in the evaluation of reasonable progress controls and that the other factors will either be considered in the cost analysis or not be a major consideration.[5] Such is the case with the add-on NOx controls of SCR and SNCR evaluated in this report. Specifically, the remaining useful life of a source is taken into account in assessing the length of time the pollution control will be in service to determine the annualized costs of controls. If there are no enforceable limitations on the remaining useful life of a source, the expected life of the pollution controls is generally considered the remaining life of the source.[6] In addition, costs of energy and water use of SNCR and SCR at a particular source are considered in determining the annual costs of these controls, which means that the bulk of the non-air quality and energy impacts are generally taken into account in the SNCR and SCR cost effectiveness analyses as is the remaining useful life of a unit. With respect to the length of time to install controls, that is not generally an issue of concern for SCR or SNCR, which can and have been installed within three to five years of promulgation of a requirement to install such controls.[7] In any event, EPA's August 20, 2019 regional haze guidance states that, with respect to controls needed to make reasonable progress, it would be inconsistent with the regional haze regulations to discount an otherwise reasonable control "simply because the time frame for implementing it falls outside the regulatory established implementation period."[8]

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[4] 40 C.F.R. §51.308(f)(2)(i).
[5] *See* U.S. EPA, August 20, 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 37.
[6] *Id.* at 33.
[7] For example, in Colorado, SCR was operational at Hayden Unit 1 in August of 2015 and at Hayden Unit 2 in June of 2016, according to data in EPA's Air Markets Program Database, within 3.5 years of EPA's December 31, 2012 approval of Colorado's regional haze plan. In Wyoming, SCR was operational at Jim Bridger Units 3 and 4 in 2015 and 2016, less than three years from EPA's January 30, 2014 final approval of Wyoming's regional haze plan. As will be discussed below, SNCR installation is much less complex than SCR, requiring primarily a sorbent storage and distribution system and boiler injection ports, and thus installation of SNCR will take less time than SCR.
[8] *See* U.S. EPA, August 20, 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 41.

A. Background on Costing Methods Used and Consideration of Remaining Useful Life and Non-Air and Energy Impacts

For the cost effectiveness analyses presented herein, EPA's Control Cost Manual Chapters for SNCR and for SCR, along with EPA's cost calculation spreadsheets,[9] were utilized with some modifications as necessary, and are described further below. In order to calculate average cost effectiveness of SNCR and SCR, one has to determine an appropriate NOx emission limit and/or percent removal efficiency to assume with the pollution control at a particular source as well as the length of time the pollution controls will be in service (which is necessary for amortizing the capital costs into annualized costs). Thus, this discussion of the costing methods will also discuss these other two factors to be taken into account in evaluating reasonable progress measures.

1. Assumptions for SNCR Cost Effectiveness Analyses.

SNCR is a NOx pollution control technology that involves injecting ammonia or an ammonia-type reactant into the furnace of a coal-fired boiler. The ammonia-type reagent mixes with hot flue gases, and the reagent reacts with NOx in the gas stream to convert some of it to nitrogen gas, thereby reducing nitrogen oxides. The NOx reduction efficiency of SNCR can vary greatly. According to EPA, "[t]emperature, residence time, type of NOx reducing agent, reagent injection rate, uncontrolled NOx level, distribution of reagent in the flue gas, and [carbon monoxide and oxygen (CO and O2)] concentrations all affect the reduction efficiency of the SNCR."[10] EPA and states, in evaluating the NOx removal efficiency of SNCR in prior analyses under the regional haze program, have assumed NOx control efficiencies with SNCR at coal-fired EGUs in the range of 15% - 40%, although typically NOx removal efficiencies in the 20-25% range have been evaluated with SNCR.[11] EPA's Control Cost Manual provides a graphical representation indicating a connection between the NOx inlet emission rate and the SNCR control efficiency, with higher NOx removal efficiencies achieved with higher inlet NOx emission rates.[12] EPA provided the following best fit equation to estimate NOx removal efficiency achievable with SNCR based on NOx inlet level:

NOx Reduction Efficiency, %, = 22.554*Inlet NOx Rate, lb/MMBtu + 16.725.[13]

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[9] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

[10] *See* EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, revised 4/25/2019, at 1-1, available at https://www.epa.gov/sites/production/files/2017-12/documents/sncrcostmanualchapter7thedition20162017revisions.pdf. *See also* Institute of Clean Air Companies White Paper, Selective Non-Catalytic Reduction (SNCR) for Controlling NOx Emissions, February 2008, at 5, attached as Ex. 1.

[11] For example, for San Juan Units 1 and 4, the SNCRs were designed to achieve a 26% reduction from the permitted emission limit of 0.30 lb/MMBtu to an emissions guarantee of 0.22 lb/MMBtu, although the actual NOx reduction efficiency between actual emissions before the SNCR to actual emissions after the SNCR was less than 26% as will be discussed further below. *See* Patscheck, Mike and David Mitchell, Reducing NOx Emissions from the San Juan Generating Station, 8/21/14, Power Engineering, available at https://www.power-eng.com/2014/08/21/reducing-nox-emissions-from-the-san-juan-generating-station/#gref.

[12] EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, 4/25/2019, at 1-3 to 1-4.

[13] *Id.* at Figure 1.1c (on page 1-4).

For the purpose of the SNCR cost-effectiveness evaluation provided here, this report uses the equation provided by EPA to estimate the SNCR NOx removal efficiency and achievable NOx emission rates for each EGU based on its pre-SNCR NOx emissions rate.

EPA suggests in the Control Cost Manual that the equipment lifetime of an SNCR system is between 15-25 years, unless limited by the remaining useful life of an emissions unit.[14] EPA stated that 11 of the 190 SNCR systems installed on utility boilers were installed before 1993, meaning the SNCR systems were operating at least 26 years at these 11 units at the time EPA issued its Control Cost Manual chapter on SNCR in April of 2019.[15] For this report, it will be assumed that an SNCR will be in operation for 25 years and that the remaining useful life of the primary EGU for which SNCR will be evaluated (Escalante Generating Station) is not a factor that would impact whether SNCR could or should be installed as a reasonable progress measure because there is no enforceable retirement date for the facility. As will be discussed further below, the New Mexico Energy Transition Act could have impacts on the remaining useful lives of the EGUs evaluated in this report, but at present there is no basis for using a remaining useful life for Escalante Generating Station shorter than the 25-year life of the SNCR system. The New Mexico Energy Transition Act is discussed in more detail further below.

The use of SNCR presents several non-air quality and energy impacts, all of which are taken into account in EPA's SNCR cost spreadsheet in estimating the annualized costs of control. Those issues include that an SNCR reduces the thermal efficiency of the boiler, which requires additional energy (fuel and electricity) to maintain the same steam output at the boiler.[16] The EPA's cost spreadsheet also takes into consideration increased ash disposal as a result of burning more fuel, as well as increased water consumption and treatment costs.[17] It must also be noted that SNCR technology is widely used at coal-fired EGUs, and the aforementioned issues are typically not overarching non-air quality or energy concerns with this technology.

2. Assumptions for SCR Cost Effectiveness Analyses.

SCR operates similarly to SNCR in using an ammonia-type reagent to reduce NOx to nitrogen gas, but NOx removal is greatly enhanced with the use of a metal-based catalyst with activated sites which increase the rate of NOx removal. The ammonia-type reagent is injected into the flue gas downstream of the combustion process through injection sites in the ductwork, which then goes into a reactor chamber that includes the catalyst. The hot gases and ammonia-type reagent diffuse through the catalyst and contact activated sites where NOx is reduced to nitrogen and water with the hot flue gases providing energy for the reaction.[18] SCR systems are routinely designed to achieve 90% or greater NOx control efficiency.[19] Annual average NOx

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[14] *Id*. at 1-54.
[15] *Id*.
[16] EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, revised 4/25/2019, at 1-28 to 1-29.
[17] *Id*. at 1-46, 1-49 to 1-53.
[18] *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 13 (available at https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf).
[19] *Id*. at pdf page 5

emission rates with SCR, along with existing low NOx burners and overfire air, can be as low as 0.04 lb/MMBtu and, for some EGUs, even lower.[20]

Specifically, there are several EGUs that have achieved NOx emission rates of 0.04 lb/MMBtu or lower on an annual average basis. A review of annual average NOx rates from EPA's Air Markets Program Database shows that Jeffrey Energy Center Unit 1 in Kansas, Edgewater Unit 5 in Wisconsin, and JH Campbell Unit 3 in Michigan have achieved annual average NOx rates with SCR as low as 0.03 lb/MMBtu.[21] Many other units have achieved 0.04 lb/MMBtu on an annual average basis, including Morgantown Unit 1 in Maryland, Gallatin Units 1 and 2 in Tennessee, Ghent Unit 4 in Kentucky, John W Turk Jr. Unit 1 in Arkansas, Wygen III in Wyoming, Dry Fork Unit 1 in Wyoming, Sandy Creek Unit 1 in Texas, W A Parish Unit 7 in Texas, Dan E Karn Unit 1 and 2 in Michigan, and Hayden Unit 1 in Colorado.[22]

In its recent regional haze revision for the Laramie River Station in Wyoming, EPA assumed 0.04 lb/MMBtu would be achieved with SCR on an annual average basis under a 0.06 lb/MMBtu NOx limit applicable on a 30-day average basis.[23] However, in its response to comments on its initial NOx BART finding for the San Juan Generating Station,[24] EPA found significant support in actual emissions data for its finding that a 0.05 lb/MMBtu NOx limit was achievable on a 30-boiler operating day average basis, including a study that identified 25 units that are achieving NOx emission rates less than 0.05 lb/MMBtu on an hourly basis.[25] EPA further cited to NOx emission rates at Seminole Units 1 and 2 (achieving 0.04 lb/MMBtu), Morgantown Units 1 and 2 (achieving 0.043 to 0.054 lb/MMBtu), Trimble Unit 1 (achieving 0.032 lb/MMBtu), as well as the Mountaineer plant and Cliffside Unit 5.[26] EPA also analyzed emissions data for the lowest NOx emitting units to calculate rolling 30-day averages (on both a calendar year basis and on a 30-boiler operating day basis).[27] EPA found several units emitting NOx at or below 0.05 lb/MMBtu, including Havana Unit 9, Parish Unit 7, and Parish Unit 8.[28]

All of this long term, actual emissions data for units equipped with SCR shows that those units with unit-specific emission limits that are more closely linked to the capabilities of the unit's NOx pollution controls consistently have met NOx rates at 0.04 lb/MMBtu on an annual

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[20] *Id.*
[21] *See* Ex.2, which is a spreadsheet with NOx emissions data from EPA's Air Markets Program Database for EGUs achieving annual average NOx rates of 0.03-0.04 lb/MMBtu with SCR.
[22] *Id.*
[23] 83 Fed. Reg. 51,403 at 51,408 (Oct. 11, 2018).
[24] This NOx BART finding for San Juan was subsequently replaced with a BART alternative, *see* 79 Fed. Reg. 60,985-60,993 (Oct. 9, 2014).
[25] *See* U.S. EPA, Complete Response to Comments for NM Regional Haze/Visibility Transport FIP, 8/5/11 (Docket EPA-R06-OAR-2010-0846) at 53 (Ex. 3). EPA also cites to Clay Erickson, Robert Lisauskas, and Anthony Licata, What New in SCRs, DOE's Environmental Control Conference, May 16, 2006., p. 28. Available here: http://www.netl.doe.gov/publications/proceedings/06/ecc/pdfs/Licata.pdf; LG&E Energy, Selective Catalytic Reduction: From Planning to Operation, Competitive Power College, December 2005, p. 75-77. (Ex. 4); and M.J. Oliva and S.R. Khan, Performance Analysis of SCR Installations on Coal-Fired Boilers, Pittsburgh Coal Conference, September 2005 (Ex. 5).
[26] *See* U.S. EPA, Complete Response to Comments for NM Regional Haze/Visibility Transport FIP, EPA-R06-OAR-2010-0846-0127, at 53-54 (Ex. 3).
[27] *Id.* at 56-58.
[28] *Id.*

average basis. Thus, for the purposes of the cost analyses presented herein, it will be assumed that the EGUs can meet a 0.04 lb/MMBtu NOx rate on an annual average basis. Given that cost-effectiveness is based on annual average costs, it is most appropriate to evaluate the NOx emission reductions achievable on an annual average basis in determining cost effectiveness.

EPA states in its current Control Cost Manual that the equipment lifetime of an SCR system at a power plant is assumed to be 30 years, based on several sources of information.[29] EPA also assumed a 30-year life of an SCR system in its cost analysis for the 2011 BART federal implementation plan (FIP) for San Juan Generating Station.[30] As stated above, EPA's guidance for the second round of regional haze implementation plans states that "[g]enerally, states can consider [the remaining useful life for stationary sources] by considering the useful life of the control system rather than the source."[31] However, in New Mexico, there are other potential constraints on the remaining useful life of coal-fired EGUs like the San Juan and Escalante Generating Stations. The New Mexico Energy Transition Act, enacted in March of 2019, requires qualifying public utilities like the majority owner of San Juan Generating Station, Public Service of New Mexico, to supply 100% of all retail sales of electricity in New Mexico by "zero carbon resources" by January 1, 2045, and a "zero carbon resource" means an "electricity generation that emits no carbon dioxide into the atmosphere…."[32] The law also requires public utilities to ensure that renewable energy comprises no less than 50% of the utility's total electricity sales to New Mexico customers by 2030 and 80% of the utility's total electricity sales to New Mexico customers by 2040. For rural electric cooperatives, the New Mexico Energy Transition Act requires 50% of total retail sales in New Mexico are to be provided by renewable energy by 2030, and the Act sets a goal for rural electric cooperatives of achieving zero carbon resources by 2050.[33] It is not clear whether power generation sources owned by municipalities are subject to these requirements in the New Mexico Energy Transition Act. This Act could serve as a constraint on the remaining useful life of a coal-fired EGU in New Mexico, although it appears to depend in part on the entity that owns the EGU. Thus, in the cost analyses provided below, two scenarios are evaluated: one in which the Energy Transition Act could limit the remaining useful life of the source and another that assumes no limit to the remaining useful life of the source. This is discussed in more detail in the discussion of the cost analyses for each unit.

The use of SCR presents several non-air quality and energy impacts, most of which are taken into account in EPA's SCR cost spreadsheet. Those issues include the parasitic load of operating an SCR system, which requires additional energy (fuel and electricity) to maintain the same steam output at the boiler.[34] The costs for the additional fuel and electricity are taken into account in EPA's SCR cost spreadsheet. The spent SCR catalyst must be disposed of in an approved landfill if it cannot be recycled or reused, although it is not generally considered

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[29] *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 80 (available at https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf).
[30] 76 Fed. Reg. 52,388 at 52,401-52,402 (Aug. 22, 2011).
[31] EPA's August 20, 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 33.
[32] New Mexico Energy Transition Act, SB0489, Section 62-15-37.F.
[33] *Id.*, Section 62-15-34.A.(3).
[34] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf pages 15-16, 48.

hazardous waste.[35] Further, the use of regenerated catalyst can reduce the amount of spent catalyst that needs to be disposed of.[36] The EPA's SCR cost spreadsheet assumed regenerated catalyst will be used and includes costs for catalyst disposal. If anhydrous ammonia is used, which EPA acknowledges is commonly used at SCR installations, there would be increased need for risk management and implementation and associated costs.[37] If urea or aqueous ammonia is used as the reagent, the hazards from use of pressurized anhydrous ammonia do not apply. None-the-less, anhydrous ammonia is commonly used in SCR installations, because it lowers SCR control costs, and any issues with handling of pressurized ammonia are well known and commonly addressed. Regardless of these impacts, SCR technology is widely used at coal-fired EGUs. There are typically not overarching non-air quality or energy concerns with this technology that negate the use of the control technology, and many of the concerns are addressed in the cost analysis.

3. Modifications to EPA's SCR and SNCR Cost Effectiveness Spreadsheets.

As previously stated, for this report, EPA's cost calculation spreadsheets for SCR and SNCR[38] were utilized, with some modifications for the cost-effectiveness evaluations presented herein. First, the cost effectiveness numbers presented herein were updated to reflect a 2018-dollar cost basis, rather than the 2016-dollar cost basis of the EPA spreadsheets.[39]

Second, the SCR cost spreadsheet was modified to account for the use of anhydrous ammonia. As stated above, EPA has acknowledged that 80% of EGUs operating SCR use ammonia as the reagent and, of those, anhydrous ammonia is used over aqueous ammonia by a ratio of 3 to 1.[40] Despite those findings, EPA's SCR cost spreadsheet does not include the data for an option to use anhydrous ammonia. Instead, EPA's SCR cost spreadsheet only address costs for urea or aqueous ammonia. Anhydrous ammonia, which is typically 99.5% ammonia, would require lower quantities of reagent than a reagent that has a lower concentration of ammonia such as aqueous which is generally 29% ammonia. While there would be increased need for and costs of risk management and implementation with anhydrous ammonia,[41] the capital and operating costs of SCR using anhydrous ammonia typically are lower than with use of urea or aqueous ammonia.[42] Aqueous ammonia is more expensive to deliver due to the large amounts of water transported with the ammonia, and the operating costs with aqueous ammonia

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[35] *Id. a*t pdf 18.
[36] *Id*. at pdf 18-19.
[37] Anhydrous ammonia is a gas at standard temperature and pressure, and so it is delivered and stored under pressure. It is also a hazardous material and typically requires special permits and procedures for transportation, handling, and storage. *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 15.
[38] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[39] Based on the 2018 CEPCI Index of 603.1.
[40] *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019 at pdf page 5.
[41] Anhydrous ammonia is a gas at standard temperature and pressure, and so it is delivered and stored under pressure. It is also a hazardous material and typically requires special permits and procedures for transportation, handling, and storage. *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 15.
[42] *Id*.

are somewhat higher due to the energy required to vaporize the water.[43] Thus, for the purposes of this report, the cost spreadsheet was amended to include data to calculate quantity and cost for use of anhydrous ammonia given the lower costs of anhydrous ammonia and its prevalent use in SCR systems. In the SCR cost spreadsheet, the primary changes that had to be made to account for use of anhydrous ammonia were to input the density of anhydrous ammonia and include a cost for anhydrous ammonia. Specifically, the SCR spreadsheet was modified to include an option for anhydrous ammonia at a concentration of 99.7% ammonia and a density of 5.1 lb/gal[44] (which converts to 38.2 lb/cubic feet). A cost of anhydrous ammonia of $280/ton was assumed in the SCR cost analysis, which reflects the United States Geological Survey's estimated average cost for 2018.[45]

EPA has stated that urea is more commonly used for SNCR applications than ammonia for larger boilers.[46] Consequently, the SNCR cost analyses presented in this report assume that urea is used as a reagent, and thus no changes were made to EPA's SNCR cost spreadsheet to take into account use of a different reagent.

EPA's SCR and SNCR cost spreadsheets are set up for a hypothetical EGU. The cost analyses presented herein used site-specific information for unit generating capacity, emissions and operational characteristics, coal quality, and considering possible constraints on each EGU's remaining useful life pursuant to the New Mexico Energy Transition Act. Aside from unit-specific characteristics, the use of anhydrous ammonia for SCR installations, and updating to a 2018-dollar cost basis, none of the other assumptions or equations in EPA's SCR and SNCR cost spreadsheets were changed.

The discussions below provide the unit-specific characteristics and provide the cost effectiveness of SCR and SNCR at three EGU units in New Mexico.

B. Analysis and Results

1. San Juan Unit 1 – Cost-Effectiveness Analysis for SCR

Unit 1 of the San Juan Generating Station is a 370 megawatt (MW) bituminous coal-fired power plant located near Waterflow, New Mexico at an elevation of 5,300 feet above sea level.[47] The unit is one of two operating coal-fired units at the site (with a currently total plant-wide generating capacity of approximately 930 MW). Two of the units (San Juan Unit 2 and Unit 3) are no longer operating as of 2017. San Juan Unit 1 was put into service in 1976.[48] San Juan Unit 1 is a Foster Wheeler wall-fired, dry-bottom pulverized coal-fired boiler equipped with low

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[43] *See* https://wahlco.com/products/aqueous-ammonia-systems/.
[44] *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019 at pdf page 16, Table 2.2.
[45] *See* USGS Minerals Commodities Summaries, 2019, available at https://prd-wret.s3-us-west-2.amazonaws.com/assets/palladium/production/atoms/files/mcs-2019-nitro.pdf.
[46] *See* EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, revised 4/25/2019, at 1-13.
[47] *See* Title V Operating Permit, Permit No. P062R3, PNM-San Juan Generating Station, at A3 and Acid Rain Phase II Permit Application at 5-6, attached as Ex. 6
[48] *See* Title V Operating Permit, Permit No. P062R3, PNM-San Juan Generating Station, at A10 (Ex. 6).

NOx burners and overfire air, SNCR, a wet limestone flue gas desulfurization (FGD) system, brominated activated carbon injection, and a baghouse.[49]

San Juan Unit 1 was subject to a best available retrofit technology (BART) determination under the Regional Haze program. In the regional haze plan for the first implementation period, EPA initially disapproved NMED's proposed BART determination and imposed a federal implementation plan (FIP) that required San Juan Unit 1 install SCR to meet a NOx BART emission limit of 0.05 lb/MMBtu applicable on a 30-boiler operating day average basis.[50] Subsequently, EPA removed its BART FIP and instead approved as part of the New Mexico State Implementation Plan (SIP) a "State Alternative" NOx BART determination for San Juan Units 1-4. Specifically, NMED's "State Alternative" was comprised of the shutdown of two units at San Juan Generating Station by December 31, 2017 and the installation of SNCR at the other two units[51] to achieve a rolling 30-boiler operating day average NOx rate across both Units 1 and 4 of 0.23 lb/MMBtu.[52] Compliance with the State Alternative had to be achieved within 15 months after EPA's final; approval of the "State Alternative," which EPA approved on October 9, 2015[53]; thus, compliance was required by January 9, 2017. It appears the SNCR was installed at San Juan Unit 1 by the beginning of 2016.[54]

Despite being subject to a state BART-alternative, it is still appropriate under the Regional Haze regulations to consider additional NOx controls to meet reasonable progress in subsequent regional haze plans. EPA's Regional Haze regulations make clear that "[a]fter a State has met the requirements for BART or implemented an emissions trading program or other alternative measure that achieves more reasonable progress than the installation and operation of BART, BART-eligible sources <u>will be subject</u> to the requirements of paragraphs (d) and (f) [the requirements for periodic comprehensive revisions to regional haze plans] of this section, as applicable, <u>in the same manner as other sources</u>." 40 C.F.R. §51.308(e)(5) [emphasis added]. Given that EPA found SCR to achieve a 30-day average NOx emission limit of 0.05 lb/MMBtu constituted BART for the four San Juan units, it is clear that San Juan Unit 1 could and should be considered for additional NOx controls to achieve lower NOx emissions than the 0.23 lb/MMBtu 2-unit average NOx limit that the unit is currently subject to. Indeed, NMED has identified the San Juan Generating Station as one of the facilities to conduct a four-factor analysis of control measures under the 2016 regional haze regulations.

Further, despite SNCR being installed on San Juan Unit 1 in 2016, it is reasonable to consider a replacement of the SNCR with SCR at San Juan Unit 1 to further reduce NOx in the second round of regional haze plans. SCR is much more effective at reducing NOx than SNCR, achieving 80-90% NOx removal compared to the roughly 20% NOx removal currently being

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[49] *See* Acid Rain Phase II Permit Application at 5 (Ex. 6); see also EPA's Air Markets Program Database for San Juan Unit 1, available at https://ampd.epa.gov/ampd/ and attached as Ex. 8.
[50] 76 Fed. Reg. 52,388 at 52,439-440 (Aug. 22, 2011).
[51] As described in EPA's proposed approval of the New Mexico "State Alternative" (79 Fed. Reg. at 26,909 at 26,913 (May 12, 2014).
[52] *See* NMED New Source Review Permit No. 0063-M8R3 for San Juan Generating Station, Condition A112.C. (at pages 24-27), attached as Ex. 7.
[53] 79 Fed. Reg. 60.978-60,985 (Oct. 9, 2014).
[54] In the Air Markets Program Database, San Juan Unit 1 is listed as equipped with SNCR beginning in January of 2016.

achieved with SNCR at San Juan Unit 1. EPA has acknowledged that the installation of a new pollutant control required in the second round of regional haze plans may necessitate the removal or discontinuation of an existing pollution control.[55] Further, although EPA recommends against including the sunk capital costs of existing pollution controls in the cost analysis for a new pollution control being considered to achieve reasonable compliance,[56] it is important to note that SNCR itself has a low capital cost relative to other air pollution control technologies.[57] The primary capital costs of SNCR are boiler injection ports and the reagent storage and distribution system, with the bulk of the cost of control being the cost of the reagent (a recurring annual operational expense as opposed to a capital expense). Further, the amount of reagent used with an SCR system is generally less than the amount of reagent used with an SNCR system, so the operating costs can often be lower with SCR compared to SNCR while achieving much greater NOx emission reductions. Replacement of the SNCR with SCR at San Juan Unit 1 would greatly reduce NOx and therefore is an appropriate measure to evaluate to make reasonable progress towards the national visibility goal for the second implementation period and beyond.

For the purpose of the SCR cost effectiveness analyses, 2012-2014 average data from the EPA's Air Markets Program Database for annual NOx emissions (in tons per year (tpy)), NOx emission rate (in pounds per million British Thermal Unit heat input (lb/MMBtu)), and megawatt-hours (MW-hrs) at San Juan Unit 1 were used to estimate pre-SCR control emissions and operations. It is not entirely clear whether the SNCR was installed sometime in 2015 or at the beginning of 2016.[58] To ensure that the pre-project emissions data does not reflect the effect of the SNCR which would not be operated if SCR was installed at San Juan Unit 1, we did not use 2015 or more recent emissions or operational data for evaluating the cost effectiveness of SCR. It would not be an accurate reflection of the cost effectiveness of SCR at San Juan Unit 1 to only consider the reduction that would be achieved from current NOx emission rates, given that the current emissions reflect the operation of SNCR, which would no longer be operating if the SNCR were replaced with SCR.

A review of historical operations levels indicates that the 2012-2014 three-year average is a reasonable projection of current and future operations at San Juan Unit 1, based on a comparison to the last few years of operations at the unit. While San Juan Unit 1 did not operate nearly as many hours in 2018 as past years, in 2019 the unit is on track to have a similar number of operating hours and gross load as the 2012-2014 average, based on the 9 months of actual operating data currently available in EPA's Air Markets Program Database. In addition, 2018

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[55] Specifically, EPA states: "In some instances, the installation of a new control may involve the removal or discontinuation of existing emission controls. Such situations present special issues and states should consult with their Regional offices. For example, it may be appropriate to account for the salvage value of dismantled equipment. We recommend against including sunk capital costs [in] the cost of compliance for any scenario." EPA's August 20, 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 31.

[56] *Id.*

[57] *See* Institute of Clean Air Companies White Paper, Selective Non-Catalytic Reduction (SNCR) for Controlling NOx Emissions, February 2008, at 7, available at https://cdn.ymaws.com/icac.site-ym.com/resource/resmgr/Standards_WhitePapers/SNCR_Whitepaper_Final.pdf.

[58] *See* Patscheck, Mike and David Mitchell, Reducing NOx Emissions from the San Juan Generating Station, Power Engineering, 8/21/2014, which indicates that the SNCR would be installed in 2015, available at https://www.power-eng.com/2014/08/21/reducing-nox-emissions-from-the-san-juan-generating-station/#gref.

may not be indicative of typical operations at San Juan Unit 1, given that the unit had a structural failure in coal silo and subsequent fire around March 21, 2018[59] which, according to the EPA's Air Markets Program Database, resulted in the unit being shut down for about 4 days and, subsequently, the unit was down from March 18, 2018 to July 2, 2018 (about 15 weeks). For all of these reasons, 2012-2014 NOx emissions and operational data were used as reflective of future year operations in the SCR cost analysis for San Juan Unit 1.

The San Juan Generating Station burns western bituminous coal from the adjacent San Juan Mine. During the 2012-2014 timeframe, the average heating value of the coal was 9,291 Btu/lb and the average sulfur content was 0.79%.[60] However, in recent years, the average heat value of the coal used at San Juan has increased. The 2016-2018 average heat value of the coal used at San Juan was 9,757 Btu/lb and the average sulfur content was 0.74%. For the purpose of determining the costs to install and operate SCR, it makes sense to use this more recent higher heat value coal data as well as more recent coal sulfur content because this data is most reflective of future coal characteristics for the San Juan Generating Station when operating SCR. Consequently, the 2016-2018 average coal heat value and sulfur content was input into the spreadsheet for the SCR costs.

Using EPA's SCR cost spreadsheet with the site-specific coal, emissions, and operational data discussed above, the costs and cost effectiveness for SCR at San Juan Unit 1 are provided in Table 1 below. This cost estimate reflects compliance with a 0.04 lb/MMBtu NOx emission rate on an annual average basis, reflecting 86% NOx removal across the SCR from the 2012-2014 annual average NOx rate achieved at San Juan Unit 1. As discussed above, a NOx removal efficiency of 86% is readily feasible for SCR. This cost estimate also assumes the use of anhydrous ammonia as the reagent. Further, this cost effectiveness analysis assumes a 30-year life of the SCR.

Table 1. Costs and Annual Average Cost Effectiveness of SCR at San Juan Unit 1 to Reduce NOx by 86% to 0.04 lb/MMBtu Assuming a Useful Life of the SCR of 30 Years[61]

Total Capital Investment for SCR, 2018$	Direct Annual Operating Costs, 2018$	Total Annualized Costs, 2018$	Annual NOx Reductions, tons per year	Cost Effectiveness of SCR
$147,040,822	$1,886,195	$12,014,054	2,780 tpy	$4,321/ton NOx removed

For the purpose of the above analysis, it was assumed the SCR would have a life of 30 years, which as discussed further above is what EPA typically assumes for the useful life of an SCR.[62] However, as discussed above, the New Mexico Energy Transition Act requires public

[59] *See* Weekend fire causes temporary shutdown of power plant unit, Farmington Daily Times, March 21, 2018, available at https://www.daily-times.com/story/news/2018/03/21/weekend-fire-causes-temporary-shutdown-power-plant-unit/447480002/.
[60] *See* spreadsheet with coal data for the San Juan Power Plant from the Energy Information Administration's Coal Data Browser, available at https://www.eia.gov/coal/data/browser/ and attached as Ex. 8.
[61] *See* Ex. 9, SCR Cost Spreadsheet for San Juan Unit 1-30 Year Life.
[62] *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 80 (available at https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf).

utilities like the majority owner of San Juan Generating Station, Public Service of New Mexico, to supply 100% of all retail sales of electricity in New Mexico by "zero carbon resources" by January 1, 2045, and a "zero carbon resource" means an "electricity generation that emits no carbon dioxide into the atmosphere…."[63] Thus, the Energy Transition Act could be interpreted to preclude PNM from burning coal at San Juan Unit 1 even with carbon capture and sequestration (CCS),[64] although the Energy Transition Act could also be interpreted to allow another entity not subject to the renewable portfolio requirements (a municipal utility such as the City of Farmington) to burn coal at San Juan beyond 2045. Therefore, an analysis of the cost effectiveness of SCR with a 20-year life of controls was also done for San Juan Unit 1, assuming SCR would be installed by January 1, 2025 and run until 2045. Those results are presented in Table 2 below.

Table 2. Costs and Annual Average Cost Effectiveness of SCR at San Juan Unit 1 to Reduce NOx by 86% to 0.04 lb/MMBtu Assuming a Useful Life of the SCR of 20 Years[65]

Total Capital Investment for SCR, 2018$	Direct Annual Operating Costs, 2018$	Total Annualized Costs, 2018$	Annual NOx Reductions, tons per year	Cost Effectiveness of SCR
$147,040,822	$1,886,195	$14,204,963	2,780 tpy	$5,109/ton NOx removed

One way to compare the costs for the SNCR installation that has already occurred at San Juan Unit 1 to the costs of SCR is to evaluate the incremental cost effectiveness of SCR over SNCR taking into account the current level of NOx removal achieved with SNCR at San Juan Unit 1. Incremental cost effectiveness of SCR over SNCR at San Juan Unit 1 is calculated by subtracting the total annualized costs of SNCR from the total annualized cost of SCR and dividing that difference in cost by the increased annual NOx reductions that would occur with SCR compared to SNCR. In order to calculate incremental cost effectiveness of going from SNCR to SCR, one has to calculate the cost effectiveness for SNCR at San Juan Unit 1. The EPA's SNCR cost spreadsheet was used for this calculation, using 2012-2014 emissions and operational characteristics as baseline emissions (which is the same period of baseline emissions and operational characteristics used in the SCR cost analysis presented herein) and assuming a controlled emission rate of 0.22 lb/MMBtu on an annual average basis (i.e., the annual average NOx rate actually achieved at San Juan Unit 1 in 2016-2018, after installation of the SNCR). As noted above, San Juan Unit 1 is achieving a NOx control efficiency with SNCR of 20.3% on an annual average basis.[66] A reduced life of the SNCR controls of 9 years was used for this analysis, to reflect the assumption that SNCR would be replaced with SCR by the beginning of 2025, before the end of the useful life of the SNCR. Based on these assumptions, the total annualized costs of the currently operating SNCR to achieve 20.3% NOx reduction at San Juan Unit 1 is calculated to be $3,284,843 and the amount of NOx removed with SNCR is calculated to be 689 tpy.[67] A 20-year life of the SCR at San Juan Unit 1 was assumed, based on the

[63] New Mexico Energy Transition Act, SB0489, Section 62-15-37.F.
[64] Carbon control and sequestration technology can control most, but not 100%, of carbon emissions from a coal-fired power plant. *See*, e.g., https://sequestration.mit.edu/.
[65] *See* Ex. 10, SCR Cost Spreadsheet for San Juan Unit 1 – 20 Year Life.
[66] *See* Ex. 11, spreadsheet with annual emissions data for San Juan Unit 1, downloaded from EPA's Air Markets Program Database.
[67] See Ex. 12, Spreadsheet with SNCR Cost Estimate for San Juan Unit 1.

potential limitations of the New Mexico Energy Transition Act discussed above. With this data, the incremental cost effectiveness of SCR compared to the currently installed SNCR is calculated as follows:

$$\frac{(\$14{,}204{,}963 - \$3{,}284{,}843)}{(2{,}780 \text{ tpy} - 689 \text{ tpy})} = \$5{,}222/\text{ton incremental cost effectiveness}$$

The replacement of SNCR with SCR would significantly improve NOx reduction efficiency at San Juan Unit 1. The annual average NOx rate would decrease from the currently achieved 0.22 lb/MMBtu with SNCR to 0.04 lb/MMBtu with SCR, resulting, on average, in an additional 2,091 tons per year of NOx reductions. Thus, replacing the SNCR with an SCR system at San Juan Unit 1 could be a very effective way for New Mexico to make reasonable progress towards the national visibility goal.

2. San Juan Unit 4– Cost Effectiveness Analysis for SCR.

Unit 4 of the San Juan Generating Station is a 560 megawatt (MW) bituminous coal-fired power plant located near Waterflow, New Mexico at an elevation of 5,300 feet above sea level.[68] San Juan Unit 4 was put into service in 1982.[69] San Juan Unit 4 is a Foster Wheeler wall-fired, dry-bottom pulverized coal-fired boiler equipped with low NOx burners with overfire air, SNCR, a wet limestone flue gas desulfurization (FGD) system, brominated activated carbon injection, and a baghouse.[70]

San Juan Unit 4 was subject to a best available retrofit technology (BART) determination under the Regional Haze program. As with San Juan Unit 1, in the regional haze plan for the first implementation period, EPA initially disapproved NMED's proposed BART determination and imposed a federal implementation plan (FIP) that required San Juan Unit 4 to install SCR to meet a NOx BART emission limit of 0.05 lb/MMBtu applicable on a 30-boiler operating day average basis.[71] Subsequently, EPA removed its BART FIP and instead approved as part of the New Mexico SIP a "State Alternative" NOx BART determination for San Juan Units 1-4. Specifically, NMED's "State Alternative" was comprised of the shutdown of two units at San Juan Generating Station by December 31, 2017 and the installation of SNCR at the other two units[72] to achieve a rolling 30-boiler operating day average NOx rate across both Units 1 and 4 of 0.23 lb/MMBtu.[73] Compliance had to be achieved within 15 months after EPA's final approval of the "State Alternative," which EPA approved on October 9, 2015,[74] thus, compliance was required by January 9, 2017. It appears the SNCR was installed at San Juan Unit 4 in late

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[68] *See* Title V Operating Permit, Permit No. P062R3, PNM-San Juan Generating Station, at A3 and Acid Rain Phase II Permit Application at 5-6 attached as Ex. 6.
[69] *See* Title V Operating Permit, Permit No. P062R3, PNM-San Juan Generating Station, at A11 (Ex. 6).
[70] *See* Acid Rain Phase II Permit Application at 5 (Ex. 6); see also EPA's Air Markets Program Database for San Juan Unit 1, available at https://ampd.epa.gov/ampd/ (attached as Ex. 8).
[71] 76 Fed. Reg. 52,388 at 52,439-440 (Aug. 22, 2011).
[72] As described in EPA's proposed approval of the New Mexico "State Alternative" (79 Fed. Reg. at 26,909 at 26,913 (May 12, 2014).
[73] *See* NMED New Source Review Permit No. 0063-M8R3 for San Juan Generating Station, Condition A112.C. (at pages 24-27), attached as Ex. 7.
[74] 79 Fed. Reg. 60.978-60,985 (Oct. 9, 2014).

2015/early 2016.[75] Despite being subject to a state BART-alternative, it is still appropriate under the Regional Haze regulations to consider additional NOx controls to meet reasonable progress in subsequent regional haze plans. EPA's Regional Haze regulations make clear that "[a]fter a State has met the requirements for BART or implemented an emissions trading program or other alternative measure that achieves more reasonable progress than the installation and operation of BART, BART-eligible sources will be subject to the requirements of paragraphs (d) and (f) [the requirements for periodic comprehensive revisions to regional haze plans] of this section, as applicable, in the same manner as other sources." 40 C.F.R. §51.308(e)(5) [emphasis added]. Given that EPA found that SCR, to achieve a 30-day average NOx limit of 0.05 lb/MMBtu, constituted BART for the four San Juan units,[76] it is clear that San Juan Unit 4 could and should be considered for additional NOx controls than the 0.23 lb/MMBtu 2-unit average NOx limit that the unit is currently subject to. As previously stated, NMED has identified the San Juan Generating Station as one of the facilities to conduct a four-factor analysis of control measures under the 2016 regional haze regulations.

Further, despite SNCR being installed on San Juan Unit 4 at the beginning of 2016, it is reasonable to consider a replacement of the SNCR with SCR at San Juan Unit 4 to further reduce NOx in the second round of regional haze plans. SCR is much more effective at reducing NOx than SNCR, achieving 80-90% NOx removal compared to the roughly 19% NOx removal achieved with SNCR at San Juan Unit 4. EPA has acknowledged that the installation of a new pollutant control required in the second round of regional haze plans may necessitate the removal or discontinuation of an existing pollution control.[77] Further, although EPA recommends against including the sunk capital costs of existing pollution controls in the cost analysis for a new pollution control being considered to achieve reasonable compliance,[78] it is important to note that SNCR itself has a low capital cost (relative to other air pollution control technologies).[79] The primary capital costs of SNCR are boiler injection ports and the reagent storage and distribution system, with the bulk of the cost of control being the cost of the reagent (a recurring annual operational expense as opposed to a capital expense). Further, the amount of reagent used with an SCR system is generally less than the amount of reagent used with an SNCR system, so the operating costs can often be lower with SCR compared to SNCR while the NOx are greatly improved. Replacement of the SNCR with SCR at San Juan Unit 4 would greatly reduce NOx and therefore is an appropriate measure to evaluate to make reasonable progress towards the national visibility goal for the second implementation period and beyond.

For the purpose of the SCR cost effectiveness analyses, 2012-2014 average data from the EPA's Air Markets Program Database for the pre-SCR lb/MMBtu NOx emissions rate. It is not

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[75] In the Air Markets Program Database, NOx emissions were reduced by about 20% starting in 2016. However, the Air Markets Program Database does not list San Juan Unit 4 as equipped with SNCR. *See* Ex. 11, spreadsheet with annual emissions data for San Juan Unit 4, downloaded from EPA's Air Markets Program Database.
[76] *See* 76 Fed. Reg. 52,388, at 52,439 (Aug. 22, 2011).
[77] EPA's August 20, 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 31.
[78] *Id*.
[79] *See* Institute of Clean Air Companies White Paper, Selective Non-Catalytic Reduction (SNCR) for Controlling NOx Emissions, February 2008, at 7, available at https://cdn.ymaws.com/icac.site-ym.com/resource/resmgr/Standards_WhitePapers/SNCR_Whitepaper_Final.pdf.

clear whether the SNCR was installed in 2015 or 2016.[80] To ensure that the pre-project emissions data did not reflect the effect of the SNCR which would not be operated if SCR was installed at San Juan Unit 4, we did not use 2016 or more recent lb/MMBtu emissions data to reflect pre-SCR NOx emission rates. However, a review of historical operation levels indicates that the 2012-2014 three year average annual megawatt-hours and annual heat input are lower than the 2016-2018 operational data, particularly for annual heat input. At the time that the SNCR was installed at San Juan Unit 4, a balanced draft conversion was also done at San Juan Unit 4.[81] Based on the annual average gross heat rate calculated from heat input (MMBtu) and gross load (MW-hours) in EPA's Air Markets Program Database, the heat rate increased after the SNCR and balanced draft conversion installations in 2015, with the 2016-2018 annual average heat rate being 8% higher than the 2012-2014 annual average heat rate.[82] This change in heat rate did not occur (based on data submitted to EPA's Air Markets Program Database) at San Juan Unit 1: the three-year average annual gross heat rate was only 0.3% higher after the SNCR and balanced draft conversion compared to the annual average heat rate over 2012-2014 based on an analysis of data submitted to EPA's Air Markets Program Database.[83] For these reasons, use of annual heat input and megawatt-hours from 2012-2014 would not be reflective of future operations of San Juan Unit 4 if SCR was installed during the second implementation period of the regional haze program. Thus, instead of using 2012-2014 operational data for San Juan Unit 4, the annual average megawatt-hours and heat rate over 2016-2018 were used in the SCR cost calculations for San Juan Unit 4, along with the pre-SCR lb/MMBtu NOx emissions rate based on the 2012-2014 annual average NOx emissions rate before the application of SNCR.

For the reasons discussed above in the section on SCR control at San Juan Unit 1, the 2016-2018 average heat value and sulfur content of the western bituminous coal used at San Juan were used in the SCR cost calculations for San Juan Unit 4, i.e., 9,757 Btu/lb heat value and 0.74% sulfur content. For the purpose of determining the costs to install and operate SCR, it makes sense to use this more recent higher heat value coal data, which reflects an increase in heat value of the coal above the 2012-2014 average. Consequently, the 2016-2018 average coal heat value and sulfur content was input into the spreadsheet for the SCR costs.

Using EPA's SCR cost spreadsheet with the site-specific coal, emissions, and operational data discussed above, the costs and cost effectiveness for SCR at San Juan Unit 4 are provided in Table 3 below. This cost estimate reflects compliance with a 0.04 lb/MMBtu NOx emission rate on an annual average basis, reflecting 85% NOx removal across the SCR from the 2012-2014 annual average lb/MMBtu NOx rate achieved at San Juan Unit 4 of 0.27 lb/MMBtu. As discussed above, a NOx removal efficiency of 85% is readily feasible for SCR. This cost estimate also assumes a 30-year life of the SCR system.

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[80] *See* Patscheck, Mike and David Mitchell, Reducing NOx Emissions from the San Juan Generating Station, Power Engineering, 8/21/2014, which indicates that the SNCR would be installed in 2015, available at https://www.power-eng.com/2014/08/21/reducing-nox-emissions-from-the-san-juan-generating-station/#gref.
[81] *Id*.
[82] *See* Ex. 11, spreadsheet with annual emissions data for San Juan Unit 1 and Unit 4, downloaded from EPA's Air Markets Program Database.
[83] *Id*.

Table 3. Costs and Annual Average Cost Effectiveness of SCR at San Juan Unit 4 to Reduce NOx by 85% to 0.04 lb/MMBtu Assuming a Useful Life of the SCR of 30 Years[84]

Total Capital Investment for SCR, 2018$	Direct Annual Operating Costs, 2018$	Total Annualized Costs, 2018$	Annual NOx Reductions, tons per year	Cost Effectiveness of SCR
$220,700,803	$2,790,097	$17,990,182	4,683 tpy	$3,842/ton NOx removed

For the purpose of the above analysis, it was assumed the SCR would have a life of 30 years, which as discussed further above is what EPA typically assumes for the useful life of an SCR.[85] However, as discussed above, the New Mexico Energy Transition Act requires public utilities like the majority owner of San Juan Generating Station, Public Service of New Mexico, to supply 100% of all retail sales of electricity in New Mexico by "zero carbon resources" by January 1, 2045.[86] Thus, the Energy Transition Act could be interpreted to preclude PNM from burning coal at San Juan Unit 4 even with carbon capture and sequestration (CCS),[87] although the Energy Transition Act could also be interpreted to allow another entity not subject to the renewable portfolio requirements (a municipal utility such as the City of Farmington) to burn coal at San Juan beyond 2045. Therefore, an analysis of the cost effectiveness of SCR with a 20-year life of controls was also done for San Juan Unit 4, assuming SCR would be installed by January 1, 2025 and run until 2045. Those results are presented in Table 4 below.

Table 4. Costs and Annual Average Cost Effectiveness of SCR at San Juan Unit 4 to Reduce NOx by 85% to 0.04 lb/MMBtu Assuming a Useful Life of the SCR of 20 Years[88]

Total Capital Investment for SCR, 2018$	Direct Annual Operating Costs, 2018$	Total Annualized Costs, 2018$	Annual NOx Reductions, tons per year	Cost Effectiveness of SCR
$220,700,803	$2,790,097	$21,278,624	4,683 tpy	$4,544/ton NOx removed

The replacement of the SNCR system with an SCR system will result in lower annual operating costs at San Juan Unit 4. EPA's SNCR cost spreadsheet was used to calculate the annual operating costs of the SNCR currently operating at San Juan Unit 4, for comparison with the annual operating costs of SCR at San Juan Unit 4. The annual reagent cost for the current SNCR operating at San Juan Unit 4 to achieve 18.9% NOx removal across the SNCR (i.e., the NOx removal efficiency currently being achieved with SNCR at San Juan Unit 4 on an annual average basis) is estimated to be approximately $3.05 million per year and the total operational costs are estimated to be $3.3 million per year, based on EPA's SNCR cost estimation spreadsheet.[89] If SNCR was replaced with SCR, the operational costs with SCR would only

[84] *See* Ex.13, SCR Cost Spreadsheet for San Juan Unit 4-30 Year Life.
[85] *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 80 (available at https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf).
[86] New Mexico Energy Transition Act, SB0489, Section 62-15-37.F.
[87] Carbon control and sequestration technology can control most, but not 100%, of carbon emissions from a coal-fired power plant. *See*, e.g., https://sequestration.mit.edu/.
[88] *See* Ex. 14, SCR Cost Spreadsheet for San Juan Unit 4-20 Year Life.
[89] *See* Ex. 15, SNCR Cost Spreadsheet for San Juan Unit 4.

decrease by almost 10% and yet the NOx removal efficiency would increase from 18.9% to 85% control and an additional 3,649 tons of NOx would be removed per year on average from San Juan Unit 4.

Another way to compare the costs for the SNCR installation that has already occurred at San Juan Unit 4 to the costs of SCR is to evaluate the incremental cost effectiveness of SCR over SNCR taking into account the current level of NOx removal achieved with SNCR at San Juan Unit 4. Incremental cost effectiveness of SCR over SNCR at San Juan Unit 4 is calculated by subtracting the total annualized costs of SNCR from the total annualized cost of SCR and dividing that difference in cost by the increased annual NOx reductions that would occur with SCR compared to SNCR. In order to calculate incremental cost effectiveness of going from SNCR to SCR, one has to calculate the cost effectiveness for SNCR at San Juan Unit 4. The EPA's SNCR cost spreadsheet was used for that purpose, using 2016-2018 annual average operational data along with the pre-SNCR annual average lb/MMBtu NOx rate over 2012-2014 of 0.27 lb/MMBtu as baseline emissions (which is the same period of baseline emissions and operational characteristics used in the SCR cost analysis presented herein) and assuming a controlled emission rate of 0.22 lb/MMBtu on an annual average basis (i.e., the annual average NOx rate actually achieved at San Juan Unit 4 in 2016-2018). As noted above, San Juan Unit 4 is achieving a NOx control efficiency with SNCR of 18.9% on an annual average basis.[90] A reduced life of the SNCR controls of 9 years was used for this analysis, to reflect the assumption that SNCR would be replaced with SCR by the beginning of 2025, before the end of the useful life of the SNCR. Based on these assumptions, the total annualized costs of the currently operating SNCR to achieve 18.9% NOx reduction at San Juan Unit 4 is calculated to be $4,563,606 and the amount of NOx removed with SNCR is calculated to be 1,088 tpy on average.[91] A 20-year life of the SCR at San Juan Unit 4 was assumed, based on the limitations of the New Mexico Energy Transition Act discussed above. With this data, the incremental cost effectiveness of SCR compared to the currently installed SNCR is calculated as follows:

$$\frac{(\$21{,}278{,}624 - \$4{,}563{,}606)}{(4{,}683 \text{ tpy} - 1{,}088 \text{ tpy})} = \$4{,}650/\text{ton incremental cost effectiveness}$$

The replacement of SNCR with SCR would significantly improve NOx reduction efficiency at San Juan Unit 4. The annual average NOx rate would decrease from the currently achieved 0.22 lb/MMBtu with SNCR to 0.04 lb/MMBtu with SCR, resulting in an additional 3,595 tons per year of NOx reductions. Thus, replacing the SNCR with an SCR system at San Juan Unit 4 could be a very effective way for New Mexico to make reasonable progress towards the national visibility goal.

[90] *See* Ex. 11, spreadsheet with annual emissions data for San Juan Unit 4, downloaded from EPA's Air Markets Program Database.
[91] See Ex. 15, Spreadsheet with SNCR Cost Estimate for San Juan Unit 4.

3. Escalante Generating Station – Cost-Effectiveness Analysis for Post-Combustion NOx Controls

The Prewitt Escalante Generating Station is a coal-fired electrical generating unit located four mile north of Prewitt, New Mexico.[92] Escalante Generating Station is comprised of a single EGU with a generating capacity of 273 MW.[93] The boiler is a dry bottom, tangentially-fired boiler fired by subbituminous coal.[94] The plant is located at an elevation of 6,890 feet above sea level.[95] The power plant is owned by Tri-State Generation & Transmission, Inc., which is a wholesale generation and transmission power cooperative. Subbituminous coal is currently received from the El Segundo Mine, although the unit also utilizes some subbituminous coal from the Lee Ranch as well.[96] Escalante Generating Station is equipped with a baghouse for particulate control, a wet scrubber for SO2 control, and dry sorbent injection for mercury control.[97] EPA's Air Markets Program Database indicates NOx controls as "other" at Escalante, and the plant's Title V permit does not indicate any NOx controls. Escalante began operating in 1984.[98]

Escalante Generating Station was not subject to a BART review during the first round of regional haze implementation plan requirements, because due to the year it constructed, it was not subject to BART. NMED also did not evaluate any controls at Escalante to achieve reasonable progress towards the national visibility goal in the first-round regional haze plan. The 3-year annual average NOx rate at Escalante over 2016-2018 was 0.35 lb/MMBtu, based on data submitted to the EPA's Air Markets Program Database, and its 2016-2018 average annual emissions were 2,334 tons per year.[99] This 3-year average emission rate is lower than typical NOx emissions were in the early 2000's when average NOx emissions were 3,600 tons per year. The Escalante unit also operated more hours and produced significantly more electricity in the 2001-2005 timeframe than it has in 2016-2018. However, beginning in approximately 2015, the unit changed from burning coal from the Lee Ranch Mine to burning coal primarily from the El Segundo Mine.[100] The El Segundo Mine coal has higher sulfur content and somewhat higher heat content than the Lee Ranch Mine coal.[101] Both of the coals are subbituminous coals, and it is not clear that either coal would have changed NOx emission rates. However, the change in coal could have changed operational characteristics of the unit, and therefore recent annual emissions averaged over 2016-2018 will be used in determining cost effectiveness of NOx

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[92] Title V Operating Permit No. P012-R3, February 24, 2017, at Prewitt Escalante Generating Station, at A3 (Attached as Ex.16).
[93] Title V Permit #O012-R2 Renewal Application Prepared for Tri-State Generation and Transmission Association, Inc., Prewitt Escalante Generating Station, August 4, 2015, at Section 1, page 2, attached as Ex. 17.
[94] *Id*. at Section 6, pages 32, 34, 35
[95] *Id*. at Section 1, page 3.
[96] *See* Ex. 18, spreadsheet with coal data for the Escalante Power Plant from the Energy Information Administration's Coal Data Browser.
[97] *See* Ex. 16, Title V Operating Permit No. P012-R3, February 24, 2017, at Prewitt Escalante Generating Station, at A10.
[98] Based on reporting to Energy Information Administration (EIA) Form 767.
[99] *See* Ex. 18, spreadsheet with coal data for the Escalante Power Plant from the Energy Information Administration's Coal Data Browser.
[100] *See* Ex. 19, NMED Statement of Basis, Title V & Acid Rain Permits, 2/24/2017, at 2-3.
[101] *See* Ex. 18, spreadsheet with coal data for the Escalante Power Plant from the Energy Information Administration's Coal Data Browser.

controls. The average heat value of the El Segundo Mine coal over 2016-2018 was 9,125 Btu/lb, the average ash content was 16.18%, and the average sulfur content was 0.99%.[102]

Using EPA's SCR cost spreadsheet with the site-specific coal, emissions, and operational data discussed above, the costs and cost effectiveness for SCR at Escalante Generating Station is provided in Table 5 below. This cost estimate reflects compliance with a 0.04 lb/MMBtu NOx emission rate on an annual average basis, which reflects 89% NOx removal across the SCR which, as discussed above, is readily achievable with SCR.

Table 5. Costs and Annual Average Cost Effectiveness of SCR at Escalante Generating Station to Reduce NOx by 89% to 0.04 lb/MMBtu, Assuming a 30-Year Life of Controls[103]

Total Capital Investment for SCR, 2018$	Direct Annual Operating Costs, 2018$	Total Annualized Costs, 2018$	Annual NOx Reductions, tons per year	Cost Effectiveness of SCR
$122,479,869	$1,402,894	$9,839,486	2,055 tpy	$4,788/ton NOx removed

The above cost estimate assumes a 30-year life of the SCR system. However, as discussed above, the New Mexico Energy Transition Act includes a goal for certain power cooperatives to supply 100% of all retail sales of electricity in New Mexico by "zero carbon resources" by January 1, 2050, and a "zero carbon resource" means an "electricity generation that emits no carbon dioxide into the atmosphere…."[104] It is unclear how this mandate could affect operation of the Escalante Generating Station, given that Tri-State is not a retail cooperative but Tri-State serves retail cooperatives. Nonetheless, an analysis of the cost effectiveness of SCR with a 25-year life of controls was also done for Escalante Generating Station, assuming SCR would be installed by January 1, 2025 and run until 2050. Those results are presented in Table 6 below.

Table 6. Costs and Annual Average Cost Effectiveness of SCR at Escalante Generating Station to Reduce NOx by 89% to 0.04 lb/MMBtu – Assuming a 25-Year Life of Controls[105]

Total Capital Investment for SCR, 2018$	Direct Annual Operating Costs, 2018$	Total Annualized Costs, 2018$	Annual NOx Reductions, tons per year	Cost Effectiveness of SCR
$122,479,869	$1,402,894	$10,537,621	2,055 tpy	$5,128/ton NOx removed

An evaluation of the costs to add on SNCR in lieu of SCR at Escalante Generating Station was also completed using EPA's SNCR cost spreadsheet. Using EPA's equation for

[102] *Id.*
[103] *See* Ex. 20, SCR Cost Spreadsheet for Escalante-30 Year Life.
[104] New Mexico Energy Transition Act, SB0489, Section 62-15-34.A.(3)(c) and Section 62-15-37.F.
[105] *See* Ex. 21, SCR Cost Spreadsheet for Escalante-25 Year Life.

expected NOx Reduction Efficiency of 22.554*Inlet NOx Rate, lb/MMBtu + 16.725,[106] it was assumed SNCR at Escalante could achieve a 24.6% reduction in NOx emissions and a corresponding NOx emission rate of 0.26 lb/MMBtu. This cost estimate assumes a 50% urea solution is used as the reagent. Consistent with EPA's Control Cost Manual chapter for SNCR, a 25-year life of the SNCR was assumed.[107] This 25-year life also reflects the likelihood that Escalante Generating Station will no longer be operating in 2050, pursuant to the New Mexico Energy Transition Act. The results of this cost effectiveness analysis are provided in Table 7 below.

Table 7. Costs and Annual Average Cost Effectiveness of SNCR at Escalante Generating Station to Reduce NOx by 24.6%, Assuming a 25-Year Life of Controls[108]

Total Capital Investment for SNCR, 2018$	Direct Annual Operating Costs, 2018$	Total Annualized Costs, 2018$	Annual NOx Reductions, tons per year	Cost Effectiveness of SNCR
$10,254,766	$1,261,850	$2,030,445	599 tpy	$3,389/ton NOx removed

To further compare SCR to SNCR, it is helpful to calculate the incremental cost effectiveness of SCR compared to SNCR. As previously discussed, incremental cost effectiveness of SCR over SNCR is calculated by subtracting the total annualized costs of SNCR from the total annualized cost of SCR and dividing that difference in cost by the increased annual NOx reductions that would occur with SCR compared to SNCR at Escalante Generating Station. For the purpose of this calculation, the SCR calculation based on a 25-year life of controls was compared to the SNCR costs. The incremental cost effectiveness of SCR compared to SNCR at Escalante Generating Station is calculated as follows:

$$\frac{(\$10{,}537{,}621 - \$2{,}030{,}445)}{(2{,}055 \text{ tpy} - 599 \text{ tpy})} = \$5{,}843/\text{ton incremental cost effectiveness}$$

As the data in Tables 6 and 7 demonstrate, SCR will result in approximately 2.5 times more NOx reductions at Escalante Generating Station than SNCR. While the costs of SCR are higher than with SNCR, SCR will also reduce 1,456 more tons of NOx per year on average compared to SNCR. Both of these controls warrant consideration by NMED in its analysis of reasonable progress controls for Escalante Generating Station.

C. Summary

The cost effectiveness of installing SCR at San Juan Units 1 and 4 and at Escalante Generating Station is within the $4,000 to $5,000/ton range, using either the standard 30-year

[106] *See* EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, revised 4/25/2019 at Figure 1.1c (on page 1-4).
[107] *Id.* at 1-54.
[108] *See* Ex. 22, SNCR Cost Spreadsheet for Escalante-25 Year Life.

remaining useful life or even with a shorter remaining useful life of 20 or 25 years, respectively. These costs should be considered to be cost effective by NMED. Data compiled by the National Park Service of SO2 BART determinations from the first-round regional haze plans shows that the costs of SO2 controls to meet BART at EGUs ranges from $1,571/ton to $7,309/ton.[109] Indeed, NMED found in its initial BART evaluation for the San Juan Generating Station from 2010 that the costs for SCR at each of the San Juan units were acceptable with costs ranging from $5,946/ton to $7,398/ton (based on PNM's cost analyses for SCR at the San Juan units submitted in 2008-2009).[110]

There are many other examples of states and EPA finding a control measure with a cost effectiveness in the $4,000 to $5,000 per ton range to be reasonable and cost effective. For example, in a regional haze plan for the first implementation period, EPA imposed a federal plan requiring reasonable progress controls based on switching to a lower sulfur fuel oil at the fuel oil-fired boilers at the Kanoelehua Hill Power Plant, the Puna Power Plant, and the Shipman Power Plant at a cost effectiveness of approximately $5,600/ton.[111] To address regional haze requirements for SO2 in the first round of regional haze plans, the state of Wyoming found that a new dry scrubber and baghouse at Dave Johnston Unit 4 was cost effective at $5,028 per ton of SO2 removed.[112] In its final action on the Wyoming regional haze plan, EPA found that costs for SCR plus low NOx burners and overfire air ranging from $2,635/ton to $4,461/ton (2008 dollars) were reasonable to require SCR as BART at Naughton Unit 3, Dave Johnston Unit 3, and at Laramie River Units 1, 2, and 3.[113] In 2008 comments to EPA Region 9 regarding BART analyses for the Four Corners Power Plant and the Navajo Generating Station, the state of Arizona stated that it has found SCR at a combined cycle power plant to be cost effective at a cost of more than $4,489/ton of NOx removed and that it saw few, if any, differences in the operation of SCR for a coal-fired EGU.[114] The State of Colorado used a $5,000/ton cost threshold for defining whether a control was cost effective in its regional haze plan for the first implementation period, and the state has indicated that the cost effectiveness threshold will be higher than $5,000/ton cost threshold in determining cost effective controls for its regional haze plan for the second implementation period.[115]

EPA advises that "[w]hen the cost/ton of a possible measure is within the range of the cost/ton values that have been incurred multiple times by sources of similar type to meet regional haze requirements *or any other [Clean Air Act] requirement*, this weighs in favor of concluding

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[109] *See* March 2011 National Park Service spreadsheet "EGUs with Proposed BART Controls." (Ex. 22).

[110] *See* June 21, 2010, NMED BART Determination, Public Service Company of New Mexico, San Juan Generating Station, Units 1-4, at 33. It is important to note that NMED found these cost numbers to be conservatively estimated by PNM and that NMED did not necessarily agree with PNM's cost estimates for SCR. Regardless, NMED found the costs to be reasonable and "in line with acceptable cost-effectiveness values for BACT determinations, which involve a similar control technology evaluation process."

[111] 77 Fed. Reg. 61,477, 61,490 (Oct. 9, 2012); *see also* 77 Fed. Reg. 31,691, 31,711-12 (May 29, 2012).

[112] *See* May 28, 2009 Wyoming Department of Environmental Quality BART Application Analysis, Dave Johnston Plant, at 23 (Ex. 3).

[113] 79 Fed. Reg. 5032-5222, at 5039-5043 (January 30, 2014).

[114] Letter from Arizona Department of Environmental Quality to Steve Fry, EPA Region IX, Re: Consultation Regarding Best Available Retrofit Technology Analyses for the Four Corners Power Plant and Navajo Generating Station, May 12, 2008. Ex. 25.

[115] *See*, e.g., Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado, January 7, 2011, at 52, 96, and 120 (attached as Ex. 26).

that the cost of compliance is not an obstacle to the measure being considered necessary to make reasonable progress."[116] Both SCR and SNCR systems have been installed at numerous EGUs throughout the United States, not only to meet regional haze requirements, but also to meet requirements to protect national ambient air quality standards (NAAQS) including the Cross State Air Pollution Rule (CSAPR), to meet major source permitting requirements or, in many cases, to avoid major source permitting requirements. For such sources that installed SNCR or SCR under other Clean Air Act programs, there may not always be available cost effectiveness analyses to compare to the cost of such controls at New Mexico EGUs but such costs could be readily estimated using EPA's SCR and SNCR cost spreadsheets for direct comparison to the cost effectiveness analyses of such controls at New Mexico EGUs.

While it is not known what cost threshold NMED will use in adopting control measures for its second round regional haze plan, NMED should keep in mind that, in determining a cost effectiveness threshold that is considered reasonable for NOx controls at coal-fired EGUs, the overarching goal of this regional haze plan revision is to make the necessary reasonable progress toward attaining the national visibility goal of preventing any future, and remedying any existing, impairment of visibility in the nation's Class I areas.

[116] *Id.* at 40.

OIL AND GAS SECTOR
REASONABLE PROGRESS
FOUR-FACTOR ANALYSIS OF CONTROLS
FOR FIVE SOURCE CATEGORIES:

NATURAL GAS-FIRED ENGINES
NATURAL GAS-FIRED TURBINES
DIESEL-FIRED ENGINES
NATURAL GAS-FIRED HEATERS AND BOILERS
FLARING AND INCINERATION

Prepared for National Parks Conservation Association

by Vicki Stamper & Megan Williams

March 6, 2020

EXECUTIVE SUMMARY

States are required to revise and submit revisions to their regional haze state implementation plans to make reasonable progress toward the national visibility goal, with the next revision due to the U.S. Environmental Protection Agency by July 31, 2021. In this second round of regional haze plans, each state needs to look broadly at the sources of visibility-impairing emissions within its state and determine the sources or source categories for which to conduct a four-factor analysis of emission reducing measures. Oil and gas development is a significant source of visibility-impairing emissions in many states, including emissions of nitrogen oxides (NOx), volatile organic compounds (VOCs), sulfur dioxide (SO_2), and particulate matter (PM).

This report conducts a four-factor analysis of reasonable progress controls for five air emission source categories within the oil and gas development industry: natural gas-fired reciprocating internal combustion engines (RICE), natural gas-fired combustion turbines, diesel-fired RICE, natural gas-fired heaters and boilers, and flaring. This report includes a compilation of information on available pollution control options for visibility-impairing pollutants, provides cost of controls (where available) and documents the cost effectiveness of controls for various size units and a range of operating levels. The report also provides information for specific pollution controls regarding the three other reasonable progress factors: the time necessary for compliance to install the controls, the energy and non-air quality environmental impacts of the controls, and the remaining useful life of both the source category and the pollution control in question, if it differs from that of the source category.

With respect to the cost of controls, the authors used control cost data that were relied upon by federal, state, and local air agencies. Also, capital costs of control were amortized based on the expected useful life of the unit unless a shorter useful life of the specific pollution control was expected, all of which is documented in the report. The authors did not escalate costs to current dollars, because in many cases, the cost information was more than five years old, and EPA's Control Cost Manual cautions against attempting to escalate costs more than five years from the original cost analysis. Last, the authors compiled information on federal, state, and local air emission limitations that were required to be met by existing sources and thus required a retrofit of pollution controls to the source category. This assessment includes an evaluation of the lowest emission limits required of existing sources by state and local agencies and correlates those emission limits to specific pollution controls. Looking to state regional haze plans, the authors note that determinations of cost effectiveness for a particular source category should be based on the costs that similar sources have had to incur to meet Clean Air Act requirements.

Although the authors attempted to identify the pollution control methods that were both cost effective and the most effective at reducing visibility-impairing emissions and evaluated varying levels of operation, it is recognized that air pollution control determinations to retrofit existing sources cannot always be implemented via a "one-size-fits-all" approach. Thus, in some cases, a few different options for retrofit pollution controls are recommended for a source category, with the primary reasons for differentiating recommended pollution controls being based on size of the unit and/or operating capacity factor. Below the authors summarize the pollution controls that are presumed to be the best control options for each source category, with a focus on NOx pollution controls.

Summary of Cost Effective Control Options for Air Emissions Sources of the Oil and Gas Sector

SOURCE CATEGORY	NOx POLLUTION CONTROL	NOx COST EFFECTIVENESS ($/TON)	PERCENT NOx REMOVAL, AND EMISSION RATES	OTHER POLLUTION CONTROLS
Natural Gas (NG)-Fired RICE Compressors	Replace with Electric Compressors	$1,228–$2,766/ton (2011 $)	100% Removal of NOx and All Other Pollutants	Power Compressors with Renewable Energy
NG-Fired RICE Rich Burn >50 hp	Nonselective Catalytic Reduction (NSCR) and Air Fuel Ratio Controller (AFRC)	$44–$3,383/ton (2009$)	94–98% 11–67 ppmv 0.16–1.0 g/hp-hr	VOC Controls integrated into NSCR.
NG-Fired RICE Lean Burn >50 hp	Low Emission Combustion (LEC)	$47–$941/ton (2001$)	87–93% 75–150 ppmv 1.0–2.0 g/hp-hr	Oxidation Catalyst for VOC Emissions
	Selective Catalytic Combustion (SCR)	$628–$13,567/ton (1999$–2001$)	90–99% 11–73 ppmv 0.15–1.0 g/hp-hr	
NG-Fired Combustion Turbines	SCR (alone or with Dry Low NOx Combustion)	$566–$13,238/ton (1999–2000$)	80–95+% 3-15 ppmv	Oxidation Catalyst for VOC Emissions
	Dry Low NOx Combustion	$208–$2,140/ton (1999$–2000$)	80–95% 9-25 ppmv	
Diesel-Fired RICE	Use Electric Engines and Tier 4 Gen Sets ---------- OR Replace Older Engines w/ Tier 4	$564–$9,921/ton (2010$)	94% 0.5 g/hp-hr ---------- 49%–96% 0.3-3.5 g/hp-hr	Catalytic Diesel Particulate Filter For PM (81%-97.5% control) Use of Ultra-Low Sulfur Diesel Fuel
	Replace w/ NG RICE	Implemented by several companies	85–94%	
	Retrofit with SCR	$3,759–$6,781/ton	90%	
Heaters/Boilers >20 MMBtu/hr	Ultra-Low NOx Burners (ULNB)	$545–$3,270/ton (2018$)	93% 6 ppmv	Other Options: Lower heater-treater temperatures Install insulation on separators
	SCR	$1,025–$6,149/ton (2018$)	97% 2.5 ppmv	
Heaters/Boilers >5 and ≤20 MMBtu/hr	ULNB	$727–$5,232/ton (2018$)	93% 6 ppmv	
Heaters/Boilers ≤5 MMBtu/hr	Replacement of Heater with New Unit with ULNB	$4,055-$10,809/ton (2005$)	82–89% 9-20 ppmv	

Note: The range of cost effectiveness for each control reflects a range of capacities of emission units and also reflects a wide range of operating hours per year. Refer to the report for more details.

As shown in the table above, there are technically feasible and cost effective options to control NOx, VOCs, PM, and SO2 from these four source categories of combustion-related emissions from the oil and gas sector and, in most cases, there are many examples of state and local air agency rules that require these or similar levels of control for existing sources. While many of these state and local rules were adopted to address the National Ambient Air Quality Standards (NAAQS), cost effectiveness of controls is generally part of the rulemaking process under reasonably available control technology (RACT) and best available retrofit control technology (BARCT – which applies in California) determinations. Given that state and local air agencies have found the costs of these controls to be reasonable for imposition of various pollution control requirements, these costs should be considered reasonable to impose to meet other Clean Air Act requirements including under the Regional Haze Program.

For flaring of waste gases, the following control options are recommended:

- Prevent flaring of excess gases through capture and use requirements instead of flaring
- Prevent flaring at gas sweetening and other processing plants by proper maintenance, training, installing duplicative equipment to minimize upsets
- Require documentation of flaring episodes with all relevant info to estimate emissions and to assess causes and actions to mitigate
- Thermal incineration should be considered in lieu of flaring due to ability for improved VOC destruction and available NOx and SO2 controls (if sour/acid gas is being combusted)

The ultimate goal to reduce VOC, NOx, PM, and SO2 emissions from excessive flaring should be to eliminate or minimize flaring to the maximum extent possible and to use, and not waste, excess gas produced.

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LIST OF TERMS

2SLB	Two-stroke lean-burn
4SLB	Four-stroke lean-burn
4SRB	Four-stroke rich-burn
A/F	Air-to-fuel ratio
ACT	Alternative control techniques
AFRC	Air/fuel ratio controller
APCD	Air pollution control district
AQMD	Air Quality Management District
BACT	Best Available Control Technology
BARCT	Best Available Retrofit Control Technology
BART	Best Available Retrofit Technology
BAT	Best Available Technology
BSFC	Brake-specific fuel consumption
BLM	U.S. Bureau of Land Management
CARB	California Air Resources Board
CEPCI	Chemical Engineering Plant Cost Index
CAA	Clean Air Act
CDPF	Catalyzed diesel particulate filter
CDPHE	Colorado Department of Public Health and Environment
CI	Compression ignition
CEMS	Continuous emissions monitoring system
CO	Carbon monoxide
CO_2	Carbon dioxide
CSAPR	Cross-State Air Pollution Rule
DRE	Destruction and removal efficiency
DPF	Diesel particulate filter
DOE	U.S. Department of Energy
DLNC	Dry low NOx combustors
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
FGR	Flue gas recirculation
4CAQTF	Four Corners Air Quality Task Force
GPU	Gas production unit
Gen Set	Generator-Set Engine
g/bhp-hr	Grams per brake horsepower-hour
g/hp-hr	Grams per horsepower-hour
HAP	Hazardous air pollutant

LIST OF TERMS

HC	hydrocarbon
H_2S	Hydrogen sulfide
hp	horsepower
kW	Kilowatt
INGAA	Interstate Natural Gas Association of America
IR	Ignition timing retard
LB	Lean-burn
LEC	Low emission combustion
LNB	Low NOx burners
MCF	Thousand cubic feet
MW	Megawatt
MMBtu	Million British Thermal Unit (heat input)
MMscf	Million standard cubic feet
NAAQS	National Ambient Air Quality Standards
NESCAUM	Northeast States for Coordinated Air Use Management
NESHAP	National Emission Standards for Hazardous Air Pollutants
NPS	National Park Service
NSPS	New Source Performance Standards
NOx	Nitrogen oxides
NMHC	Non-methane hydrocarbons
NSCR	Nonselective catalytic reduction
NSPS	New Source Performance Standards
OTC	Ozone Transport Commission
PEMS	Parametric emissions monitoring system
PM	Particulate matter
$PM_{2.5}$	Particulate matter with an aerodynamic diameter equal to or less than 2.5 microns
ppm	Parts per million
ppmv	Parts per million by volume
ppmvd	Parts per million dry volume
PSC	Prestratified charge
PSD	Prevention of Significant Deterioration
psig	Pounds per square inch gauge
RACT	Reasonably Available Control Technology
RECLAIM	Regional Clean Air Incentives Market
RHR	Regional Haze Rule
RB	Rich-burn
RICE	Reciprocating internal combustion engine(s)

LIST OF TERMS

SMAQMD	Sacramento Metropolitan Air Quality Management District
SCAQMD	South Coast Air Quality Management District
SCR	Selective catalytic reduction
SI	Spark ignition
SJVAPCD	San Joaquin Valley Air Pollution Control District
SNCR	Selective noncatalytic reduction
SO_2	Sulfur dioxide
SOx	Sulfur oxides
TCEQ	Texas Commission on Environmental Quality
TSD	Technical support document
THC	Total hydrocarbons
ULSD	Ultra-low sulfur diesel
ULNB	Ultra-low NOx burners
VCAPCD	Ventura County Air Pollution Control District
VOC	Volatile organic compound

I. BASIS FOR REASONABLE PROGRESS CONTROLS

Under the Regional Haze Rule (RHR), states are required to revise and submit periodic comprehensive revisions to their regional haze plans, with the next revision due to be submitted to the U.S. Environmental Protection Agency (EPA) by July 31, 2021.[1] This next round of regional haze plans is referred to as the regional haze plan for the second implementation period. States' regional haze plans address regional haze in all Class I areas within the state and in all Class I areas located outside the state that may be affected by emissions from within the state.[2] Each state's plan and plan revision must include, among other things, a long term strategy which is to be determined as follows:

> Each State must submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for each mandatory Class I Federal area located outside the State that may be affected by emissions from the State. The long-term strategy must include enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress, as determined pursuant to [40 C.F.R. § 51.308] (f)(2)(i) through (iv). In establishing its long-term strategy for regional haze, the State must meet the following requirements:
>
> (i) The State must evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering 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 anthropogenic source of visibility impairment. The State should consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources. The State must include in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy. In considering the time necessary for compliance, if the State concludes that a control measure cannot reasonably be installed and become operational until after the end of the implementation period, the State may not consider this fact in determining whether the measure is necessary to make reasonable progress.
>
> . . .

40 C.F.R. § 51.308(f)(2)(i).

The requirement for evaluation of emission reduction measures quoted above is generally referred to as a "four-factor analysis" or a "reasonable progress analyses" of controls. To reiterate, the four factors that must be considered when evaluating reasonable progress controls for a source are (1) cost of compliance, (2) time necessary for compliance, (3) the energy and non-air quality environmental impacts of compliance, and (4) the remaining useful life of the source. In the first round of regional haze plans, States were required to evaluate and impose emission limitations that reflect "best available

[1] 40 C.F.R. § 51.308(f).
[2] *Id.*

retrofit technology" (BART) at all BART-subject sources (which were clearly defined by regulation). States also were required to identify sources to control in order to make reasonable progress towards the national visibility goal; for these sources states tended to focus on the larger single sources of emissions, as was also the focus of BART controls. In the second round of regional haze plans, each state needs to look more broadly at the sources of visibility-impairing emissions within its state and determine the sources or source categories for which to conduct a four-factor analysis of controls. Each state must adopt emission-reduction measures in its regional haze plan developed for the second implementation period to make reasonable progress towards the national visibility goal. The Clean Air Act (CAA) mandated that regional haze plans must address sources of "emissions from which may reasonably be anticipated to cause or contribute to ***any*** impairment of visibility" (emphasis added)).[3]

Air emissions from oil and gas development, production, treatment, and transmission represent a significant quantity of regional haze-impairing emissions in many states. Air emissions from oil and gas development that can impact visibility include nitrogen oxides (NOx), sulfur dioxide (SO_2), directly emitted particulate matter (PM), volatile organic compounds (VOCs), and ammonia. NOx, SO_2, VOCs, and ammonia, initially emitted as gases, often convert into fine (i.e., less than 2.5 micrometers in diameter) particulate matter ($PM_{2.5}$) in the atmosphere, which can travel far and which are very efficient in scattering light and impacting visibility. Oil and gas development often occurs on federal, state, and/or private lands near or even adjacent to Class I areas. Oil and/or gas development tends to be clustered in certain areas where such fossil fuels are found. Many of the air emissions sources associated with gas and/or oil production are minor sources, not large enough in emissions to trigger new source review permitting. However, such sources collectively are often significant contributors to visibility impairment in Class I areas due to sheer numbers of emission sources or proximity to Class I areas, or both.

In the United States, oil and gas production has been increasing and is projected to continue to increase in the future. States with significant increases in oil production since 2013 include Colorado with almost a tripling of production since 2013, New Mexico with more than a doubling of production since 2013, Texas with a 73% increase in production since 2013, and North Dakota with a 48% increase since 2013.[4] States with significant increases in gas production include, among others, Ohio with annual gas production in 2018 that is more than 14 times higher than it was in 2013, West Virginia with a 143% increase in gas production since 2013, North Dakota with a doubling of production in 2018 compared to 2013, Pennsylvania with a 91% increase in gas production since 2013, and New Mexico with a 27% increase in gas production since 2013.[5] The U.S. Energy Information Administration (EIA) currently projects crude oil production in the United States to be 25% higher in 2021 than it was in 2018[6] and marketed gas production in the United States to be 13% higher in 2021 than it was in 2018.[7] In many areas of the country, these increases in production are projected to continue well into the future. For

[3] 42 U.S.C. § 7491(b)(2).
[4] EIA, Crude Oil Production, Annual-Thousand Barrels, 2013 to 2018, *available at:* https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm.
[5] EIA, Natural Gas Gross Withdrawals and Production, Marketed Production, Annual Million Cubic Feet, 2013 to 2018, *available at:* https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_a.htm.
[6] EIA Short-Term Energy Outlook, U.S. Liquid Fuels, January 14, 2020, *available at:* https://www.eia.gov/outlooks/steo/report/us_oil.php.
[7] EIA, Short-Term Energy Outlook, Natural Gas, January 14, 2020, *available at:* https://www.eia.gov/outlooks/steo/report/natgas.php.

example, the New Mexico Oil and Gas Association recently presented a report to state lawmakers indicating that there will be "solid growth for the next decade or so" in the Permian Basin.[8]

There are several combustion-related sources of visibility-impairing emissions associated with oil and gas development. Various engines, typically fired by natural gas or diesel, are used in the drilling and completion phase, in the processing of natural gas, and at compressor stations. On-site power sources are often used, in the form of natural gas-fired engines, diesel generators, and/or combustion turbines. Natural gas-fired boilers and heaters are also used throughout the oil and gas production and process segments of the industry, to generate power, and to create steam and process heat. Those engines and combustion turbines emit significant quantities of NOx and VOCs and also of SO_2 and PM for diesel-fired engines. Flaring of excess and waste gas can be a significant source of SO_2 and NOx emissions.

This report presents a four-factor analysis of reasonable progress controls for NOx and VOCs, and SO_2 and PM as appropriate, for five significant air emissions source categories associated with oil and gas development: natural gas-fired reciprocating internal combustion engines (RICE), natural gas-fired combustion turbines, diesel-fired RICE, natural gas-fired boilers and heaters, and flaring/incineration of waste or excess gas. This report (1) proposes pollution controls and/or measures for such sources considering the control technology available and the most effective controls; (2) compiles cost data with a focus on data relied upon by federal, state, and local air agencies in regulatory decisions; (3) evaluates non-air quality environmental and energy impacts of controls; and (4) considers the remaining useful life of the equipment.

It is important to note that, while New Source Performance Standards (NSPS) exist for these source categories, the existence of an NSPS does not negate the need for a four-factor analysis of controls to achieve reasonable progress towards the national visibility goal for several reasons. First, it has been many years since the NSPS standards for RICE units, gas turbines, and small boilers have been re-evaluated. Although EPA correctly states in its 2019 Regional Haze guidance that "[t]he [CAA] requires EPA to review, and if necessary, revise NSPS every 8 years,"[9] EPA has not always updated the NSPS emission standards for a source category in accordance with this timetable. Second, the NSPS emission standards only apply to a facility if it is constructed, modified, or reconstructed after the applicability date.[10] The applicability date of an NSPS (or of a revised NSPS emission standard) is set as either the date of publication of any proposed or of any final rulemaking establishing the standard. Third, when EPA adopts or revises NSPS for a source category, EPA is establishing an emission standard applicable to all of the source types and variable fuels, operating conditions, etc. that exist for that source category. Thus, the NSPS are generally applicable emission standards and not a source-specific evaluation of controls.

Further, while EPA's Regional Haze guidance states that, if a new or modified unit is subject to and complying with an NSPS promulgated or reviewed since July 31, 2013, it is unlikely that new or existing controls are available or more effective, no such assumption should be made without considering the

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[8] As discussed in Report: New Mexico oil, gas boom to continue, by Susan Montoya Bryan/Associated Press, September 3, 2019, Albuquerque Journal, *available at:* https://www.abqjournal.com/1361629/report-new-mexico-oil-gas-boom-to-continue.html.

[9] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019, at 23, note 44.

[10] *See* 40 C.F.R. § 60.1(a); *see also* definitions in § 60.2 and regulations on "modification" and "reconstruction" in §§ 60.14 and 60.15.

specific emission and operational characteristics of the source in question. EPA's statements are problematic and need clarification. One cannot simply determine the last time the NSPS for a source category was amended and assume that if the amendments occurred within the last eight years, the NSPS is up to date. Section 111(b)(1)(B) of the CAA requires EPA to review and revise each NSPS at least every eight years, to essentially determine if the NSPS currently reflect the "degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[11] EPA amends its NSPS for various reasons (e.g., changes in test methods or protocols, clarifications), but thorough reviews and revisions generally occur much less frequently — in many cases less frequently than every eight years as required by the CAA. Table 1 below shows the NSPS applicable to RICE units, turbines, and small boilers and provides the most recent date of EPA's comprehensive review and revision. The NSPS rules applicable to RICE units and gas turbines were last subject to a comprehensive revision to reflect the best-demonstrated technology well before July 31, 2013.

Table 1. NSPS Categories that Address RICE, Natural Gas Turbines, and Small Boilers

NSPS Subpart in 40 C.F.R. Part 60	Emission Source(s)	Date of Promulgation of Most Recent Revisions
Dc	Small Industrial-Commercial-Institutional Steam Generating Units	2/27/06 (reflects most recent review of the emission standards)
GG	Stationary Gas Turbines	9/20/79 (first promulgation of NSPS for gas turbines and revised standards promulgated at Subpart KKKK)
IIII	Stationary Compression Ignition Internal Combustion Engines	6/28/11 (reflects most recent adoption of emission standards for this source category)
JJJJ	Stationary Spark Ignition Internal Combustion Engines	1/18/08 (NSPS for source category first promulgated, and reflects most recent review of emission standards)
KKKK	Stationary Combustion Turbines constructed, reconstructed or modified after 2/18/05	7/6/2006 (first promulgation of NSPS Subpart KKKK, and reflects most recent review of emission standards)
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution for which Construction. Modification, or Reconstruction Commenced after 8/23/11 and on or before 9/15/15	6/3/2016 (reflects most recent review the emission standards)
OOOOa	Crude Oil and Natural Gas Production, Transmission, and Distribution from which Construction. Modification, or Reconstruction Commenced after 9/18/15	6/3/2016 (NSPS Subpart first promulgated)

[11] *See* Section 111(a)(1) of the Clean Air Act, 42 U.S.C. § 7411(a)(1).

Thus, while the NSPS may be a place to start in evaluating pollution controls for air emissions sources associated with the oil and gas industry, it is also necessary to evaluate if more stringent requirements and pollution controls have been required in state rules or local air rules, air permits, or other requirements. Review of state regulations and state implementation plans, particularly to address national ambient air quality standards (NAAQS) which requires reductions in emissions from existing sources, is necessary to fully evaluate controls for emission sources associated with oil and gas development to achieve reasonable progress towards the national visibility goal.

The information provided below reflects a comprehensive review of the pollution controls and techniques and associated emissions levels applicable to each of the source categories, along with data on cost of controls where available, non-air quality environmental and energy impacts, and the reasonable useful life of the emission source being evaluated.

II. CONTROL OF NOx EMISSIONS FROM NATURAL GAS-FIRED RECIPROCATING INTERNAL COMBUSTION ENGINES

Reciprocating internal combustion engines (RICE) are used in a variety of applications, including gas compression, pumping, and power generation. RICE can either be: (1) spark-ignited and fueled by natural gas, propane, or gasoline; or (2) compression-ignited and fueled by diesel. Spark-ignition engines fueled by natural gas, propane, and gasoline can operate lean (i.e., with a higher air-to-fuel ratio) or rich (i.e., with a lower air-to-fuel ratio). Compression-ignition diesel-fueled engines operate lean. A rich-burn engine operates with excess fuel during combustion, whereas a lean-burn engine operates with excess air.

Natural gas-fired RICE are the focus of this section and are used throughout the oil and gas industry, as described by EPA:

> Most natural gas-fired reciprocating engines are used in the natural gas industry at pipeline compressor and storage stations and at gas processing plants. These engines are used to provide mechanical shaft power for compressors and pumps. At pipeline compressor stations, engines are used to help move natural gas from station to station. At storage facilities, they are used to help inject the natural gas into high pressure natural gas storage fields. At processing plants, these engines are used to transmit fuel within a facility and for process compression needs (e.g., refrigeration cycles). The size of these engines ranges from 50 brake horsepower (bhp) to 11,000 bhp. In addition, some engines in service are 50–60 years old and consequently have significant differences in design compared to newer engines, resulting in differences in emissions and the ability to be retrofitted with new parts or controls.
>
> At pipeline compressor stations, reciprocating engines are used to power reciprocating compressors that move compressed natural gas (500–2000 [pounds per square inch gauge (psig)]) in a pipeline. These stations are spaced approximately 50 to 100 miles apart along a pipeline that stretches from a gas supply area to the market area. The reciprocating compressors raise the discharge pressure of the gas in the pipeline to overcome the effect of frictional losses in the pipeline upstream of the station, in order to maintain the required

> suction pressure at the next station downstream or at various downstream delivery points. The volume of gas flowing and the amount of subsequent frictional losses in a pipeline are heavily dependent on the market conditions that vary with weather and industrial activity, causing wide pressure variations. The number of engines operating at a station, the speed of an individual engine, and the amount of individual engine horsepower (load) needed to compress the natural gas is dependent on the pressure of the compressed gas received by the station, the desired discharge pressure of the gas, and the amount of gas flowing in the pipeline. Reciprocating compressors have a wider operating bandwidth than centrifugal compressors, providing increased flexibility in varying flow conditions. Centrifugal compressors powered by natural gas turbines are also used in some stations and are discussed in another section of this document.[12]

Natural gas-fired reciprocating engines are also used at well sites across the oil and gas industry in various applications including, e.g., reciprocating compressors and pump engines used to lift oil out of a well.

Natural gas-fired RICE can be classified as two-stroke or four-stroke engines. In a two-stroke engine, the power cycle occurs in a single crankshaft revolution and two strokes: an intake/compression stroke; and a power/exhaust stroke. In a four-stroke engine, the power cycle is completed with two crankshaft revolutions and four strokes: an intake stroke; compression stroke; power stroke; and exhaust stroke. Natural gas-fired RICE units encompass three engine types or classes:

1. Two-stroke lean-burn (2SLB)
2. Four-stroke lean-burn (4SLB)
3. Four-stroke rich-burn (4SRB)

NOx emissions from RICE are highly dependent on combustion temperature, with higher temperatures resulting in more NOx emissions. Rich-burn engines operate with an air-to-fuel ratio (A/F) that is rich with fuel resulting in higher fuel use, increased combustion temperatures, increased engine power, and decreased engine efficiency relative to a lean-burn engine. Lean-burn engines operate with an A/F that is lean with fuel resulting in less fuel use, decreased combustion temperatures, decreased engine power, and increased engine efficiency relative to a rich burn engine.

UNITS

NOx emissions from RICE are generally expressed as emission rates in grams per brake horsepower hour (g/bhp-hr) or as a concentration in parts per million by volume (ppmv or ppmvd). All concentrations expressed in ppmv are on a dry basis and corrected to 15% oxygen. Emission rates expressed in g/bhp-hr and grams per horsepower-hour (g/hp-hr) are assumed to be roughly equivalent for the RICE applications in this section. The following conversion factors from EPA's Updated Information on NOx Emissions and Control Techniques document* are used in this section:

[12] EPA, AP-42, Fifth Edition, Volume 1, Chapter 3: Stationary Internal Combustion Sources.

Uncontrolled rich-burn Spark-Ignition (SI) engines and rich-burn engines controlled with nonselective catalytic reduction (NSCR)……..67 ppmv = 1 g/bhp-hr
Uncontrolled lean-burn engines, lean-burn engines controlled with selective catalytic reduction (SCR), and rich-burn engines controlled with prestratified charge™ (PSC) technology……73 ppmv = 1 g/bhp-hr
Lean-burn engines controlled with Low Emission Combustion (LEC) Technology……..75 ppmv = 1 g/bhp-hr
* EPA, Stationary Reciprocating Internal Combustion Engines Updated Information on NOx Emissions and Control Techniques, September 2000 (EPA-457/R-00-001)

A. RICH-BURN RICE: COMBUSTION CONTROLS

Emission control technologies for RICE depend on the A/F and therefore different controls apply to different engine types. NOx emissions reductions from these engines can be achieved through combustion controls or through post-combustion (add-on) controls. The following retrofit combustion control technologies for rich-burn RICE are described by EPA in its *Alternative Control Techniques Document – NOx Emissions from Stationary Reciprocating Internal Combustion Engines*, and EPA's descriptions are reprinted below:[13]

Rich-Burn A/F Adjustments

> Adjusting the A/F toward fuel-rich operation reduces the oxygen available to combine with nitrogen, thereby inhibiting NOx formation. The low-oxygen environment also contributes to incomplete combustion, which results in lower combustion temperatures and, therefore, lower NOx formation rates. The incomplete combustion also increases [carbon monoxide (CO)] emissions and, to a lesser extent, [hydrocarbons (HC)] emissions. Combustion efficiency is also reduced, which increases brake-specific fuel consumption (BSFC). Excessively rich A/F's may result in combustion instability and unacceptable increases in CO emissions.
>
> The A/F can be adjusted on all new or existing rich-burn engines. Sustained NOx reduction with changes in ambient conditions and engine load, however, is best accomplished with an automatic A/F control system.
>
> The achievable NOx emission reduction ranges from approximately 10 to 40 percent from uncontrolled levels. Based on an average uncontrolled NOx emission level of 15.8 g/hp-hr (1,060 ppmv), the expected range of controlled NOx emissions is from 9.5 to 14.0 g/hp-hr (640

[13] EPA-453/R-93-032 *Alternative Control Techniques Document – NOx Emissions from Stationary Reciprocating Internal Combustion Engines* (July 1993), *available at*: https://www3.epa.gov/airquality/ctg_act/199307_nox_epa453_r-93-032_internal_combustion_engines.pdf [hereinafter referred to as "EPA 1993 Alternative Control Techniques Document for RICE"].

> to 940 ppmv). Available data show that the achievable NOx reduction using A/F varies for each engine model and even among engines of the same model, which suggests that engine design and manufacturing tolerances influence the effect of A/F on NOx emission reductions.[14]

NOx Removal Efficiency:	*10-40%*
Controlled NOx Emission Rates:	*9.5 to 14.0 g/hp-hr*
	640 to 940 ppmv

Rich-Burn Ignition Timing Retard (IR)

> Ignition timing retard delays initiation of combustion to later in the power cycle, which increases the volume of the combustion chamber and reduces the residence time of the combustion products. This increased volume and reduced residence time offer the potential for reduced NOx formation. . . .
>
> Ignition timing can be adjusted on all new or existing rich-burn engines. Sustained NOx reduction with changes in ambient conditions and engine load, however, is best accomplished using an electronic ignition control system.
>
> The achievable NOx emission reduction ranges from virtually no reduction to as high as 40 percent. Based on an average uncontrolled NOx emission level of 15.8 g/hp-hr (1,060 ppmv), the expected range of controlled NOx emissions is from 9.5 to 15.8 g/hp-hr (640 to 1,060 ppmv). Available data and information provided by engine manufacturers show that, like AF, the achievable NOx reductions using IR are engine-specific.[15]

NOx Removal Efficiency:	*0-40%*
Controlled NOx Emission Rates:	*9.5 to 15.8 g/hp-hr*
	640 to 1,060 ppmv

A/F adjustment and IR can be employed together to reduce NOx emissions from rich-burn RICE. According to EPA, the achievable emissions reductions are similar to that for A/F adjustments (i.e., 10-40%) but may offer the potential to minimize some of the adverse impacts of other operating parameters (e.g., CO emissions, engine response, fuel consumption).[16]

Limited cost data indicate that combustion controls for rich-burn RICE costs between $400 to $1,000 per ton of NOx reduced for engines greater than 500 horsepower (hp).[17]

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[14] *Id.* at 2-5.
[15] *Id.* at 2-5 and 2-9.
[16] *Id.* at 2-9.
[17] *Id.* at 2-30. *See also* California Air Resources Board (CARB) Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines, November 2001, Table V-2 at V-3, *available at*: https://ww3.arb.ca.gov/ractbarc/rb-iceall.pdf [hereinafter referred to as "CARB 2001 Guidance"]. The CARB cost effectiveness analysis assumes the engines are run at 100% load for 2,000 hours per year, annualized costs are figured based on an interest rate of 10% over a 10-year life.

B. RICH-BURN RICE: PRESTRATIFIED CHARGE (PSC)

Prestratified charge (PSC) is a combustion modification that converts rich-burn engines to lean-burn engines by retrofitting the air injectors to make a leaner A/F ratio. PSC is described by EPA in its Alternative Control Techniques Document for RICE, as follows:

> This add-on control technique facilitates combustion of a leaner A/F. The increased air content acts as a heat sink, reducing combustion temperatures, thereby reducing NOx formation rates. Because this control technique is installed upstream of the combustion process, PSC® is often used with engines fueled by sulfur-bearing gases or other gases (e.g. sewage or landfill gases) that may adversely affect some catalyst materials.
>
> Prestratified charge applies only to four-cycle, carbureted engines. Pre-engineered, "off-the-shelf" kits are available for most new or existing candidate engines, regardless of age or size. According to the vendor, PSC® to date has been installed on engines ranging in size up to approximately 2,000 hp.
>
> The vendor offers guaranteed controlled NOx emission levels of 2 g/hp-hr (140 ppmv), and available test data show numerous controlled levels of 1 to 2 g/hp-hr (70 to 140 ppmv). The extent to which NOx emissions can be reduced is determined by the extent to which the air content of the stratified charge can be increased without excessively compromising other operating parameters such as power output and CO and HC emissions. The leaner A/F effectively displaces a portion of the fuel with air, which may reduce power output from the engine. For naturally aspirated engines, the power reduction can be as high as 20 percent, according to the vendor. This power reduction can be at least partially offset by modifying an existing turbocharger or installing a turbocharger on naturally aspirated engines. In general, CO and HC emission levels increase with PSC®, but the degree of the increase is engine-specific. The effect on BSFC is a decrease for moderate controlled NOx emission levels (4 to 7 g/hp-hr, or 290 to 500 ppmv), but an increase for controlled NOx emission levels of 2 g/hp-hr (140 ppmv) or less.[18]

PSC NOx Removal Efficiency:	*87% (85-90%, EPA 2000)*[19]
Controlled NOx Emission Rates:	*2 g/hp-hr*
	140 ppmv

PSC NOx reduction efficiency depends on how much the air content can be increased without adversely affecting the performance of the engine; achieving lower NOx rates with PSC will result in sacrifices in engine power output. PSC, generally, can only achieve a NOx emission rate as low as 2 g/bhp-hr. EPA re-affirmed the limitations of PSC in its 2000 Updated Information on NOx Emissions and Control Techniques for RICE, stating:

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[18] EPA 1993 Alternative Control Techniques Document for RICE at 2-9 to 2-10.

[19] EPA-457/R-00-001 *Stationary Reciprocating Internal Combustion Engines Updated Information on NOx Emissions and Control Techniques,* September 2000, *available at*: https://nepis.epa.gov/Exe/ZyPDF.cgi/P100V343.PDF?Dockey=P100V343.PDF [hereinafter referred to as "EPA 2000 Updated Information on NOx Emissions and Control Techniques"].

> The 1993 ACT document found that the achievable NOX emission level for PSC is 2.0 g/bhp-hr, based on the vendor's guarantees. This value is generally consistent with the information gathered for this project and is a representative value for the NOX emission level that can be achieved using PSC control technology.[20]

Limited cost data indicate that PSC achieving 80% NOx reduction efficiency costs between $200 to $800 per ton of NOx reduced for engines ranging in size from 50–1,500 hp.[21]

Even the best-case NOx emissions reductions for PSC are generally lower than the emissions reductions that can be accomplished with the nonselective catalytic reduction (NSCR) technologies discussed below. And NSCR also generally costs less, with capital and annual costs less than PSC for almost all engine sizes, according to data from EPA.[22] However, for fuels with higher sulfur content (e.g., waste gases), PSC technology can be effective at achieving NOx emissions reductions where higher sulfur fuels would adversely impact catalyst material used in post-combustion control technologies such as NSCR.

C. RICH-BURN RICE: NONSELECTIVE CATALYTIC REDUCTION (NSCR)

The use of NSCR technology began in the 1970s with the application of 3-way catalysts to gasoline-fueled motor vehicles in order to simultaneously control carbon monoxide, VOCs, and NOx emissions. In automobiles, the technology is known as a "catalytic convertor." Since then, NSCR has been widely applied to stationary engines. NSCR is usually also accompanied by an air/fuel ratio controller (AFRC), which is used to adjust the combustion parameters across the operating range of the engine in order to maintain the conditions needed for the efficient operation of the NSCR system (e.g., sufficient excess oxygen in the exhaust gas).

NSCR is described by EPA in its Alternative Control Techniques Document for RICE, as follows:

> Nonselective catalytic reduction is essentially the same catalytic reduction technique used in automobile applications and is also referred to as a three-way catalyst system because the catalyst reactor simultaneously reduces NO_X, CO, and HC to water (H_2O), carbon dioxide (CO_2), and diatomic nitrogen (N_2). The chemical stoichiometry requires that O_2 concentration levels be kept at or below approximately 0.5 percent, and most NSCR system require that the engine be operated at fuel-rich A/F's. . . .
>
> Nonselective catalytic reduction applies only to carbureted rich-burn engines and can be retrofit to existing installations. Sustained NOx reductions are achieved with changes in ambient conditions and operating loads only with an automatic A/F control system. . . .

[20] *Id.* at 4-21.
[21] *See* CARB 2001 Guidance at Table V-2 at V-3. The CARB cost effectiveness analysis assumes the engines are run at 100% load for 2,000 hours per year, annualized costs are figured based on an interest rate of 10% over a 10-year life.
[22] *See* EPA's 1993 Alternative Control Techniques Document for RICE Table 2-12 at 2-30.

> Catalyst vendors quote NOx emission reduction efficiencies of 90 to 98 percent. Based on an average uncontrolled NOx emission level of 15.8 g/hp-hr (1,060 ppmv), the expected range of controlled NOx emissions is from 0.3 to 1.6 g/hp-hr (20 to 110 ppmv). . . .
>
> The predominant catalyst material used in NSCR applications is a platinum-based metal catalyst. The spent catalyst material is not considered hazardous, and most catalyst vendors accept return of the material, often with a salvage value that can be credited toward purchase of replacement catalyst.[23]

NSCR NOx Removal Efficiency:	*90-98%*
Controlled NOx Emission Rates:	*0.3 to 1.6 g/hp-hr*
	20 to 110 ppmv

According to EPA, when California air district standards were tightened to 96% NOx reduction and emission limits of 25 ppmv (0.37 g/bhp-hr), facilities shifted from PSC to NSCR to meet the standard.[24] This level of NOx control can be met with an NSCR retrofit to an existing unit. For example, retrofit installations of NSCR on five Caterpillar rich burn engines in Texas achieved a NOx reduction of 96% or greater on all of the engines.[25] On two of those engines, testing conducted after more than 4,000 hours of operation with NSCR indicated the NSCR controls were still achieving a 95% NOx reduction.[26] Employing NSCR to reduce NOx emissions from EPA's uncontrolled emission rate of 15.8 g/bhp-hr to 1.0 g/bhp-hr corresponds to a NOx emission reduction efficiency of 94%. Unless otherwise noted, the analyses provided further below in this section assume a 94% NOx reduction efficiency to meet a 1 g/bhp-hr emission rate. Lower NOx emission limits have been required by some states and local agencies that reflect a higher NOx removal efficiency (see Section II.G., below).

NSCR can effectively reduce CO, HC, VOCs (include formaldehyde), as well as NOx emissions, if properly optimized for control of all these pollutants. Such systems must control the A/F carefully to provide enough oxygen to ensure that CO and VOCs are oxidized but also limit oxygen enough to ensure the NOx is effectively reduced. The oxygen content of the exhaust gas needs to be within a narrow window to ensure effective control of all three pollutants, and thus an AFRC is necessary along with an oxygen sensor to provide feedback to the AFRC to ensure the proper fuel-rich operation.

HOURS OF OPERATION FOR RICE

Stationary RICE are used in a variety of applications throughout the oil and gas sector, from providing on-site power, driving pumps or compressors, and drilling operations at well sites to driving pipeline compressor stations to powering pumps, compressors, and refrigeration at gas processing plants. Because of the varying uses for RICE units, RICE units used in the oil and gas sector cover the full

[23] EPA 1993 Alternative Control Techniques Document for RICE at 2-10 to 2-11.
[24] EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-19.
[25] OTC Technical *Information Oil and Gas Sector Significant Stationary Sources of NOx Emissions* October 17, 2012, *available at*: https://otcair.org/upload/Documents/Meeting%20Materials/Final%20Oil%20%20Gas%20Sector%20TSD%2010-17-12.pdf at 45.
[26] *Id.*

range of operating schedules. In providing cost estimates herein, this report presents cost effectiveness analyses to reflect operating as few as 2,000 hours per year and as high as 8,000 hours per year. For example, compressor stations typically operate continuously, although not all compressor engines at a compressor station operate continuously. On the other hand, RICE units used for backup onsite electrical generation may not operate much at all in a year. Thus, a low-end operating capacity factor and a high-end capacity factor were assumed to reflect a range of costs across varying levels of operation.

A cost effectiveness analysis of NSCR was performed in 2010 for EPA, to help determine national impacts associated with EPA's final rule for Reciprocating Internal Combustion Engine National Emission Standards for Hazardous Air Pollutants (RICE NESHAP).[27] The analysis, performed by E^C/R Incorporated, was based on 2009 cost data for retrofitting NSCR on existing 4SLB engines from industry groups, vendors, and manufacturers of RICE control technology. E^C/R Incorporated performed a linear regression analysis[28] on the data set to determine the following linear equation for annual cost, which includes annual operating and maintenance costs plus annualized capital costs based on a 7% interest rate and 10-year life of controls:

NSCR Annual Cost = $4.77 x (hp) + $5,697 (2009$)

The capital cost equation for retrofitting an AFRC and NSCR on a 4SRB engine was determined by E^C/R Incorporated to be, as follows:

NSCR Capital Cost = $24.9 x (hp) + $13,118 (2009$)

These relationships are derived from a data set that includes engines ranging in size from 50–3,000 hp.

The E^C/R document does not explain why it assumed a 10-year life of controls for estimating the annualized capital costs. The life of a RICE unit is generally much longer than ten years, and is often at least thirty years.[29] The assumed 10-year life was not based on the catalyst replacement timeframe, because the E^C/R operating costs took into account the cost for replacing the catalyst every three years, as well as replacing the thermocouple every 7.5 years, the crankcase filters every three months, the oxygen sensor on a quarterly basis, and rotating the catalyst for cleaning annually.[30] Thus, the assumed 10-year life of an NSCR system seems arbitrary. In cost analyses done in 2000 for EPA, an equipment life of NSCR of fifteen years was assumed.[31] The state of Colorado also recently assumed a 15-year life of

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[27] Memo from E^C/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010), *available at*: https://www.epa.gov/sites/production/files/2014-02/documents/5_2011_ctrlcostmemo_exist_si.pdf.

[28] *Id.* The report notes that the linear equation has a correlation coefficient (R) of 0.7987, concluding that it "shows an acceptable representation of cost data."

[29] *See, e.g.*, EPRI, 20 Power Companies Examine the Role of Reciprocating Internal Combustion Engines for the Grid, *available at*: https://eprijournal.com/start-your-engines/. The authors also note that, in reviewing permits for gas processing facilities and compressor stations in New Mexico, it is not uncommon to have engines that were constructed from the 1950's to 1970's still operating at such facilities.

[30] Memo from E^C/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010), at 4 and at 11, 13, and 15.

[31] *See* August 11, 2000, E.H. Pechan & Associates, Inc., NOx Emissions Control Costs for Stationary Reciprocating Internal Combustion Engines in the NOx SIP Call States, at 5 and at A-2, *available at*: https://www3.epa.gov/ttn/ecas/regdata/cost/pechan8-11.pdf. *See also* EPA, Regulatory Impact Analysis for the NOx SIP Call, IP, and Section 126 Petitions, September 1998, at 5-5 (Table 5-3).

NSCR for RICE units.[32] Given that EPA assumed a selective catalytic reduction (SCR) system at an industrial fossil fuel-fired boiler has a life of 20-25 years,[33] it seems very likely that NSCR would have a useful life of at least fifteen years if not longer. For the purpose of the NSCR cost analyses presented herein, a 15-year life of the NSCR system was assumed.

In addition, a lower interest rate than 7% is assumed in determining annualized costs of controls for this report, to be consistent with EPA's Control Cost Manual which recommends the use of the bank prime interest rate.[34] The bank prime rate fluctuates over time, and the highest it has been in the past five years is 5.5%.[35] In its cost calculation spreadsheet for SCR provided with its Control Cost Manual, EPA also used an interest rate of 5.5%.[36] Thus, a 5.5% interest rate has been used for the revised cost calculations presented herein.

Table 2 shows the cost effectiveness of NSCR and an AFRC achieving 94% NOx reduction efficiency and operating at 2,000 hours per year and 8,000 hours per year, based on these cost equations from EPA's 2010 RICE NESHAP, adjusted to reflect a 5.5% interest rate and 15-year life of controls.

Note that lower NOx emission limits have been required by some states and local agencies that reflect a higher NOx removal efficiency than the 94% assumed in the table below (see Section II.G.) and the costs of employing NSCR to meet these lower limits will be even more cost effective than what is shown here.

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[32] *See* Colorado Department of Public Health and Environment, Air Pollution Control Division, Reasonable Progress Evaluation for RICE Source Category, circa 2008 [hereinafter referred to as "CDPHE RP for RICE"], at 8, *available at*: https://www.colorado.gov/pacific/sites/default/files/AP_PO_Reciprocating-Internal-Combustion-Engine-RICE-engines_0.pdf.

[33] *See* EPA, Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, at pdf page 80, *available at*: https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf.

[34] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, *available at*: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.

[35] *See, e.g.*, https://fred.stlouisfed.org/series/DPRIME.

[36] *Available at:* https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

Table 2. Cost Effectiveness to Reduce NOx Emissions from Rich-Burn RICE with NSCR and an AFRC, Based on EPA RICE NESHAP Cost Equations for Existing Stationary Spark-Ignition (SI) Engines[37]

ENGINE TYPE	SIZE, hp	ANNUALIZED COSTS OF NSCR AND AFRC, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 2,000 HR/YR, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 8,000 HR/YR, 2009$
RICH-BURN	50	$5,303	$3,251/ton	$813/ton
	200	$5,859	$898/ton	$224/ton
	500	$6,971	$427/ton	$107/ton
	1,000	$8,824	$270/ton	$68/ton
	2,500	$14,382	$176/ton	$44/ton

TABLE NOTES:

- Cost data are assumed to be in 2009$, based on E^C/R Incorporated analysis of vendor and industry group data for engines ranging from 50–3,000 hp (EPA RICE NESHAP, 2010).
- Recalculated for 15-year life of controls and 5.5% interest rate.
- Assumes 94% NOx removal efficiency.

Colorado requires emissions from rich-burn RICE greater than 500 hp be controlled using NSCR with an AFCR. This requirement applies statewide to engines for which control costs are below $5,000 per ton of NOx reduced.[38] In its initial regional haze plan, Colorado completed a Reasonable Progress Evaluation for the RICE Stationary Source Category, including a NOx emission 4-Factor analysis for reasonable progress toward the national visibility goal.[39] In its evaluation, Colorado reported that, "[f]ew of the statewide rich burn RICE demonstrated control costs exceeding the $5,000 cost off-ramp. Consequently, the state concluded that such NSCR controls are installed on the majority of rich burn RICE over 500 HP statewide."[40] Colorado further reports that "[n]one of the operators of rich burn RICE outside the [Denver] metro-area ozone non-attainment area submitted information demonstrating control costs in excess of $5,000 per ton cost threshold, consequently, the majority of natural-gas fired RB RICE over 500 HP must operate an NSCR with an AFR controller."[41]

Colorado's Reasonable Progress Evaluation for RICE listed the capital and annual operating costs for retrofitting existing engines with NSCR and an AFCR, which are reiterated in Table 3.

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[37] *See* Memo from E^C/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010). Annualized costs of control were calculated using a capital recovery factor of 0.099626 (assuming a 15-year life of controls and a 5.5% interest rate). Uncontrolled NOx emissions are based on EPA's 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032) and a 94% NOx removal efficiency.
[38] Colorado Regulation Number 7, *see* Section XVII.E.3.a.
[39] CDPHE RP for RICE.
[40] *Id.* at 4.
[41] *Id.* at 8.

Table 3. Capital and Operating Costs of NSCR with AFCR[42]

SOURCE CATEGORY	CAPITAL COSTS, 2003$*	ANNUAL OPERATING AND MAINTENANCE COSTS, 2003$*
RICH-BURN RICE > 500 hp	$35,000	$6,000
TABLE NOTES: *Colorado's cost estimates are from its "Denver Early Action Compact Analysis of Stationary Sources," dated 2003. Colorado does not specify, but it is assumed the cost data are from the 2003 timeframe.		

Colorado determined the annualized costs of control assuming a 15-year life of controls and indicating that, "[g]enerally the operational life of a catalyst is approximately 5 to 15 years, depending on factors such as how it is maintained and the particular duty cycle of the engine."[43] Colorado's use of a 15-year life of controls is also consistent with previous EPA analysis.[44] The annualized capital cost in Colorado's analysis of $4,851 appears to assume roughly a 10% interest rate, with total annualized costs – i.e., annualized capital costs plus annual operating and maintenance costs – of $10,851.[45] To be consistent with EPA's Control Cost Manual, which recommends the use of the bank prime interest rate, a lower interest rate than 10% is assumed in determining annualized costs of controls for this report.[46] As previously discussed, it is more appropriate to use a lower interest rate of 5.5%.[47] Thus, the cost data were revised to be consistent with the EPA's Control Cost Manual in assuming a 5.5% interest rate in amortizing the capital costs. [48]

Colorado presented the cost effectiveness of retrofitting RICE greater than or equal to 500 hp with NSCR and an AFCR based on 2008 NOx emissions reductions for 305 RICE units located outside the nonattainment area of the state. However, the more generalized approach used in this report of assuming 94% control effectiveness is consistent with Colorado's requirement that these engines – controlled with NSCR and an AFCR – meet an emission limit of 1 g/hp-hr.[49] Again, using EPA's uncontrolled emission rate of 15.8 g/bhp-hr, the NOx emissions reduction efficiency of meeting a 1 g/hp-hr NOx limit for these engines is approximately 94%.[50]

The following table shows the cost effectiveness of a 500 hp RICE unit operating at 2,000 hours per year and at 8,000 hours per year and employing NSCR and an AFRC to meet a 1 g/hp-hr NO_x limit, based on a 15-year life and 5.5% interest rate.

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[42] *Id.*
[43] *Id.* at 10.
[44] EPA, Regulatory Impact Analysis for the NOx SIP Call, IP, and Section 126 Petitions, September 1998, at 5-5 (Table 5-3).
[45] CDPHE RP for RICE at 8.
[46] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.
[47] *See, e.g.*, https://fred.stlouisfed.org/series/DPRIME.
[48] *See, e.g.*, https://fred.stlouisfed.org/series/DPRIME.
[49] *See* Colorado Regulation Number 7, *see* Section XVII.E.2.b.
[50] EPA 1993 Alternative Control Techniques Document for RICE.

Table 4. Cost Effectiveness to Reduce NOx Emissions from Rich-Burn RICE with NSCR and an AFRC To Meet a 1 g/hp-hr NO_x Limit [51]

ENGINE TYPE	SIZE, hp	ANNUALIZED COSTS OF NSCR AND AFRC, 2003$	COST EFFECTIVENESS OF NSCR AND AFRC AT 2,000 HR/YR, 2003$	COST EFFECTIVENESS OF NSCR AND AFRC AT 8,000 HR/YR, 2003$
RICH-BURN	500	$9,487	$582/ton	$145/ton

TABLE NOTES:

- Cost data are assumed to be in 2003$, based on Colorado's Reasonable Progress Evaluation for the RICE Source Category.
- Analysis assumes 15-year life of controls and 5.5% interest rate.
- Analysis assumes 94% NOx removal efficiency.

NSCR for Smaller Rich-Burn RICE and Cyclically-Loaded RICE (< 500 hp)

California Air Districts have long been regulating NOx emissions from RICE, including engines smaller than 500 hp, and the California Air Resources Board (CARB) issued guidance to Air Districts in 2001 on the best available retrofit technologies for controlling NOx emissions from a broad range of stationary RICE.[52]

In the 1990s, when EPA first issued its Alternative Control Techniques document for stationary RICE, over 90% of all natural gas-fueled RICE were well pumps with an average size of 15 hp operating, on average, 3,500 hours per year.[53] Today, these smaller well pump engines likely make up a smaller share of nationwide RICE applications across the oil and gas industry, with continued growth in gas production and associated compression and processing applications. However, NOx emissions from these smaller pumping engines, on a regional scale, can be significant. For example, NOx emissions from artificial lifts (e.g., beam pumping used to push oil to the surface) in the New Mexico counties of the Permian Basin make up 13% of all NOx emissions.[54] The average rated horsepower of these engines is 21 hp and the magnitude of these NOx emissions – inventoried in 2014 – was close to 4,000 tons.

[51] *See* CDPHE RP for RICE. Annualized costs of control were calculated using a capital recovery factor of 0.099626 (assuming a 15-year life of controls and a 5.5% interest rate). Uncontrolled NOx emissions are based on EPA's 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032) and a 94% NOx removal efficiency.
[52] CARB 2001 Guidance.
[53] EPA 1993 Alternative Control Techniques Document for RICE Table 3-1 at 3-14.
[54] IWDW 2014 Oil and Gas Emissions Inventories, *available at:* http://views.cira.colostate.edu/wiki/wiki/9170/2014-oil-and-gas-emissions-inventories.

CARB's 2001 guidance discusses RICE units derated[55] to less than 50 hp, indicating that, "[o]ne of the largest categories of the derated engines are cyclically-loaded units used to drive reciprocating oil pumps."[56]

Two specific concerns with respect to the applicability of NSCR to certain types of smaller pump engines used in the oil and gas sector include: (1) the impact that moisture and sulfur in the fuel have on the catalyst; and (2) the impact that variable engine loading has on maintaining sufficient temperatures. Some fuel gases contain high amounts of moisture and sulfur which can result in damage to (deactivation of) the catalyst. The sulfur content of pipeline-quality natural gas is low but some oil field gases can contain high sulfur concentrations. And in applications where engines are periodically idle or where the load is cyclical, it can be more difficult to maintain an adequate exhaust gas temperature. For example, for an oil well pump, the engine may operate at load for a time-period lasting from several seconds to around 20 seconds, followed by an equal amount of time idle. These limitations can generally be minimized through design and maintenance activities, e.g., by treating the field gas to reduce the moisture and sulfur content, heating the catalyst to avoid deactivation, thermally insulating the exhaust pipe and catalyst to maintain a proper temperature, etc.[57]

CARB recognized that these characteristics (e.g., cyclic loads and variable fuel composition) would, "tend to discourage the use of catalysts with air-to-fuel controllers." But CARB specifically noted that, "a review of source test data in [CARB's 2001 Guidance] indicates that there have been instances where these engines have been successfully controlled in the past by cleaning up the field gas, and 'leaning-out' the engine or installing a catalyst in some cases."[58]

Specifically, cyclic engines that drive certain oil pumps (e.g., beam- or crank-balanced pumping engines) fueled by oil field gas operate in a way that may adversely impact the effectiveness of NSCR control. Following are specific pump engine types, as defined in Santa Barbara County Air Pollution Control District (APCD) Rule 333 Control of Emissions from Reciprocating Internal Combustion Engines:[59]

> "Air-balanced pumping engine" means a noncyclically-loaded engine powering a well pump, with the pump using compressed air in a cylinder under the front of the walking beam to offset the weight of the column of rods and fluid in the well, eliminating the need for counterweights.

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[55] CARB describes a derated engine as, "one in which the manufacturer's brake horsepower rating has been reduced through some device which restricts the engine's output." CARB 2001 Guidance at IV-1.
[56] *See* CARB 2001 Guidance at IV-1.
[57] *Id.*; *also see* South Coast Air Quality Management District Preliminary Draft Staff Report for Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines (July 2019), D-4, *available at:* http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1110.2/rule-1110-2-pdsr_07172019.pdf?sfvrsn=6.
[58] *See* CARB 2011 Guidance at IV-1.
[59] Santa Barbara County APCD Rule 333 CONTROL OF EMISSIONS FROM RECIPROCATING INTERNAL COMBUSTION ENGINES, 333.C at 333-2, *available at:* https://ww3.arb.ca.gov/drdb/sb/curhtml/r333.pdf.

"Beam-balanced pumping engine" means a cyclically-loaded engine powering a well pump, with the pump counterweight on the back end of the walking beam. The counterweight is moved mechanically without a cylinder supplying air pressure.

"Crank-balanced pumping engine" means a cyclically-loaded engine powering a well pump, with the pump counterweight attached to a gearbox which is attached to the walking beam with a pitman arm. The counterweight is moved mechanically, in a circular motion, without a cylinder supplying air pressure.

"Cyclically-loaded engine" means an engine that under normal operating conditions has an external load that varies by 40 percent or more of rated brake horsepower during any load cycle or is used to power a well reciprocating pump including beam-balanced or crank-balanced pumps. Engines powering air-balanced pumps are noncyclically-loaded engines.

In Santa Barbara County APCD, cyclic rich-burn engines (beam- and crank-balanced pump engines) greater than 50 hp are expected to meet a NOx limit of 300 ppmv, corrected to 15% oxygen, by adjusting the A/F mixture (to operate lean) and properly tuning and maintaining the engines; these engines are not required to install add-on NSCR control. However, according to CARB's guidance, cyclic rich-burn engines have met emission limits as low as 50 ppmv (< 1 g/bhp-hr) by "using NSCR or by leaning the air/fuel mixture in conjunction with treating the field gas to reduce moisture and sulfur content."[60] Specifically, the following engine test data demonstrate emission rates under 50 ppmv (corrected to 15% oxygen) for pump engines:

Table 5. Pump Engine Test Data[61]

CA AIR DISTRICT	ENGINE TYPE	ENGINE SIZE[62]	CONTROL TECHNOLOGY	# OF TESTS	NOx EMISSIONS [ppmv corrected to 15% oxygen]
Santa Barbara	Air-balanced oil pumps	195 hp	NSCR	18	2-14
Santa Barbara	Beam- and crank-balanced oil pumps	131 hp	Leaning of A/F mixture	4	12-35
Santa Barbara	Beam- and crank-balanced oil pumps	39-46 hp	Leaning of A/F mixture	16	8-28
Santa Barbara	Beam- and crank-balanced oil pumps	39-49 hp	Leaning of A/F mixture	18	7-33
Ventura	Beam- and air-balanced oil pumps	Not specified	NSCR	5	50

[60] *See* CARB 2001 Guidance at IV-5.

[61] *Id.*at IV-5 to IV-6.

[62] Oil pump engines, sometimes derated, are typically less than 50 hp, however there do appear to be some engines used for oil pumping applications that are larger, as shown in this table. And in addition, the underlying source test data in CARB's 2001 Guidance from Santa Barbara County and Ventura County also include a few data points for rich-burn engines less than 50 hp with NSCR, e.g., four 48 hp engines in Santa Barbara County with NSCR, and a 48 hp engine and 25 hp engine in Ventura County with catalyst control. *See* CARB 2001 Guidance Tables D-2 and D-3.

CA AIR DISTRICT	ENGINE TYPE	ENGINE SIZE[62]	CONTROL TECHNOLOGY	# OF TESTS	NOx EMISSIONS [ppmv corrected to 15% oxygen]
Ventura	Beam- and air-balanced oil pumps	Not specified	NSCR	3	25
TABLE NOTE: the field gas used in these engines was either naturally low in sulfur or treated to pipeline-quality natural gas					

CARB concluded that, "[b]ecause of the demonstrated success of meeting the 50 ppmv NOx limit for cyclic rich-burn engines fueled by low-sulfur or treated field gas, we recommend that the districts consider the cost effectiveness of field gas treatment and emission controls in setting limits for these engines on a site-specific basis."[63] Essentially, CARB guidance proposed considering in its cost effectiveness analysis, the additional cost of field gas treatment including the material and labor costs of piping the treated fuel from the gas processing unit to the engine.

As of January 1, 2017, the San Joaquin Valley Air Pollution Control District (SJVAPCD) requires emissions from rich-burn RICE meet the following NOx limits:

Table 6. NOx Emission Limits for All Rich-Burn Non-Agricultural Operations Engines Rated at > 50 bhp[64]

ENGINE TYPE		NOx LIMIT [ppmvd corrected to 15% O2]	EQUIVALENT NOx LIMIT Converted to g/bhp-hr
4SRB	Cyclic Loaded, Field Gas Fueled	50	0.7
	Limited Use	25	0.4
	All other	11	0.2
TABLE NOTES: Conversions to g/bhp-hr limits are based on: 67 ppmv = 1 g/bhp-hr (per EPA's 1993 Alternative Control Techniques Document, page 4-11)[65]			

SJVAPCD completed a cost effectiveness analysis for the second phase of its internal combustion engine rule (Rule 4702) in 2003.[66] The District analyzed a broad array of control scenarios to meet these NOx limits including installing NSCR on both cyclic and non-cyclic rich-burn RICE of wide-ranging power output and capacity utilization.

[63] *See* CARB 2001 Guidance at IV-6.
[64] SJVAPCD Rule 4702 Internal Combustion Engines, Tables 1 and 2, *available at*: https://www.valleyair.org/rules/currntrules/r4702.pdf.
[65] SJVAPCD Rule 4702 Cost Effectiveness Analysis (July 17, 2003), at B-3, *available at*: https://ww3.arb.ca.gov/pm/pmmeasures/ceffect/reports/sjvapcd_4702_report.pdf.
[66] *Id.*

SJVAPCD found that the costs to install and operate NSCR at cyclically-loaded RICE units to meet the limit in Table 6 above were cost effective, with costs ranging from $394/ton to $20,272/ton (1999$), which reflected costs of NSCR assuming a 10-year life and a 10% interest rate.[67]

To use more current data on NSCR costs applied to cyclically-loaded units, the E^c/R cost equations provided in Section II.C. above were used to estimate cost effectiveness for cyclically-loaded RICE units. As previously stated, the E^c/R cost equations take into account the addition of an AFRC as well as the costs of the NSCR. It was assumed that the NSCR system would achieve 90% control of NOx at cyclically-loaded engines as is required by the Santa Barbara emission limit.[68] To reflect varying levels of operation, emission reductions were based on operating 2,000 hours per year, 4,500 hours per year, and 8,000 hours per year. Texas Commission on Environmental Quality (TCEQ) data for artificial lifts operating in the Permian Basin indicates that such units operate 4,380 hours per year, although a much higher annual hours of operation of 7,106 has been assumed for artificial lift engines in the Greater San Juan Basin.[69] Thus, to give a range of cost effectiveness of NSCR at cyclically-loaded units, cost effectiveness of NSCR was determined for a low, medium, and high number of operating hours per year. As with other NSCR cost effectiveness analyses, a 15-year life and a 5.5% interest rate were assumed. The results of this cost effectiveness analyses are presented in Table 7.

[67] *Id.* at B-2 and at Table 3.

[68] Santa Barbara County APCD Rule 333 CONTROL OF EMISSIONS FROM RECIPROCATING INTERNAL COMBUSTION ENGINES, 333.C at 333-2.

[69] November 2016, RAMBOLL ENVIRON, San Juan and Permian Basin 2014 Oil and Gas Emission Inventory Inputs Final Report, at 25 and Appendix A at A-1, *available at*: https://www.wrapair2.org/pdf/2016-11y_Final%20GSJB-Permian%20EI%20Inputs%20Report%20(11-09).pdf.

Table 7. Cost Effectiveness to Reduce NOx Emissions from Rich-Burn Cyclically-Loaded RICE Units with NSCR and AFRC, Based on EPA RICE NESHAP Cost Equations for NSCR[70]

ENGINE TYPE	SIZE (hp)	ANNUALIZED COSTS OF NSCR, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 2,000 HR/YR, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 4,500 HR/YR, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 8,000 HR/YR, 2009$
RICH-BURN	50	$5,303	$3,383/ton	$1,504/ton	$846/ton
	75	$5,396	$2,295/ton	$1,020/ton	$574/ton
	100	$5,489	$1,751/ton	$778/ton	$438/ton
	250	$6,045	$771/ton	$343/ton	$193/ton
	500	$6,971	$445/ton	$198/ton	$111/ton

TABLE NOTES:

- Cost data are assumed to be in 2009$, based on E^C/R Incorporated analysis of vendor and industry group data (EPA RICE NESHAP, 2010).
- Recalculated for 15-year life of controls and 5.5% interest rate.
- Assumes 90% NOx removal efficiency.

CARB's 2001 Guidance and the cost effectiveness analysis in this section for RICE units smaller than 500 hp show that application of NSCR to engines less than 500 hp can be cost effective. For RICE units used in oil pumping applications CARB describes situations where NSCR has been applied to cyclic rich-burn RICE to meet limits as low as 50 ppmv, citing certain types of "grasshopper" oil well pumps in Santa Barbara County.[71] And for oil pumping RICE units less than 50 hp CARB identified electrification (discussed in Section II.F, below), in addition to A/F adjustments and catalytic control, as technically feasible approaches to reducing NOx emissions from engines of this size.[72]

Further, SJVAPCD Rule 4702 for Internal Combustion Engines has a provision for RICE units at least 25 bhp, up to, and including 50 bhp that requires units that are sold after July 2012 to meet the applicable requirements and emission limits of EPA's NSPS for spark-ignition internal combustion engines in 40 CFR Subpart Part 60, JJJJ, for the year in which the ownership of the engine changes.[73] In the response to comments on its NSPS Subpart JJJJ rulemaking,[74] EPA provides many examples of the successful application of NSCR on small rich-burn engines and variable-load engines (noted as pumpjack engines or

[70] *Id*. Annualized costs of control were calculated using a capital recovery factor of 0.099626 (assuming a 15-year life of controls and a 5.5% interest rate). Uncontrolled NOx emissions are based on EPA's 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032) and control efficiency of 90%.

[71] CARB 2001 Guidance at IV-5. "Source tests of NSCR-equipped cyclic engines in Santa Barbara County have shown that these engines can be effectively controlled with or without air/fuel controllers provided the oil well pumps are air-balanced units."

[72] CARB 2001 Guidance at II-1.

[73] SJVAPCD Rule 4702 Internal Combustion Engines Section 5.1

[74] 73 Fed. Reg. 3,568-3,614 (Jan. 18, 2008).

compressor engines) that justify its standards as achievable and demonstrated for very small rich-burn RICE.[75]

Application of NSCR to rich-burn RICE is cost effective for a wide range of engine sizes and types.

While the cost estimates and cost algorithms in this section are of a cost basis that is from the 1999–2009 timeframe, it is important to note that, from at least 2001, several state and local air agencies have found that the costs of control to achieve NOx emission limits of 1 g/bhp-hr (67 ppmvd) and even lower NOx emission limits were cost effective to require such a level of control on existing rich-burn RICE. This will be discussed further in Section II.G. below. It is not possible to accurately escalate these costs to 2019 dollars. The Chemical Engineering Plant Cost Index (CEPCI) has been used extensively by EPA for escalating costs, but EPA states that using the CEPCI indices to escalate costs over a period longer than five years can lead to inaccuracies in price estimation.[76] Further, the prices of an air pollution control do not always rise at the same level as price inflation rates. As an air pollution control is required to be implemented more frequently over time, the costs of the air pollution control often decrease due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc.

The environmental and energy impacts of NSCR for rich-burn RICE include the following:

- 0 to 5% increase in fuel consumption resulting in increased CO_2 emissions[77]
- 1 to 2% reduction in power output[78]
- Increased solid waste disposal from spent catalysts.[79]

The impacts on increased fuel consumption and increased solid waste disposal are taken into account in the cost effectiveness analysis. Further, NSCR has been installed extensively on RICE units in the United States, and these non-air quality environmental and energy impacts are not generally considered to be impediments to implementing the control.

NSCR can be installed fairly quickly. The Institute of Clean Air Companies indicates that "off-the-shelf" NSCR converters can be installed in six to eight weeks. For NSCR installations that are more site-specific, NSCR can be installed in approximately fourteen weeks.[80]

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[75] *See* EPA's Response to Public Comments on Spark-Ignition (SI) New Source Performance Standards (NSPS)/National Emission Standards for Hazardous Air Pollutants (NESHAP), posted to EPA's docket on January 2, 2008, Docket ID EPA-HQ-OAR-2005-0030-0249, at 95-100, *available at*: https://www.regulations.gov/document?D=EPA-HQ-OAR-2005-0030-0249.

[76] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.

[77] *See* EPA 1993 Alternative Control Techniques Document for RICE Table 3-1 at 3-14.

[78] *Id.* Table 2-4 at 2-8.

[79] CDPHE RP for RICE at 10 (citing EPA (2002), EPA Air Pollution Control Cost Manual, 6th ed., EPA/452/B-02-001, EPA, Office of Air Quality Planning and Standards, RTP).

[80] Institute of Clean Air Companies, Typical Installation Timelines for NOx Emissions Control Technologies on Industrial Sources, December 4, 2006 at 9, *available at:* https://cdn.ymaws.com/www.icac.com/resource/resmgr/ICAC_NOx_Control_Installatio.pdf.

D. LEAN-BURN RICE: LOW EMISSION COMBUSTION (LEC)

Low emission combustion (LEC) retrofit kits are designed to achieve extremely lean A/F in order to minimize NOx emissions. The various retrofit technologies can include:

- Redesign of cylinder head and pistons to improve mixing (on smaller engines)
- Precombustion chamber (on larger engines)
- Turbocharger
- High energy ignition system
- Aftercooler
- AFRC[81]

According to EPA, "[n]ew spark-ignition engines equipped with LEC technology are, by definition, lean-burn engines."[82] A wide range of emission rates are achievable with LEC technology, with emissions generally no higher than 2 g/hp-hr and often significantly lower. EPA's updated information on stationary RICE NOx emissions and control technologies concludes, for lean-burn engines, an emission rate of 2.0 g/bhp-hr is achievable for "new engines and most engines retrofitted with LEC technology."[83] LEC is described by EPA in its Alternative Control Techniques Document, as follows:

> Low-emission combustion designs are available from engine manufacturers for most new SI engines, and retrofit kits are available for some existing engine models. For existing engines, the modifications required for retrofit are similar to a major engine overhaul, and include a turbocharger addition or upgrade and new intake manifolds, cylinder heads, pistons, and ignition system. The intake air and exhaust systems must also be modified or replaced due to the increased air flow requirements.
>
> Controlled NOx emission levels reported by manufacturers for [LEC] are generally in the 2 g/hp-hr (140 ppm) range, although lower levels may be quoted on a case-by-case basis. Emission test reports show controlled emission levels ranging from 1.0 to 2.0 g/hp-hr (70 to 140 ppmv). Information provided by manufacturers shows that, in general, BSFC decreases slightly for [LEC] compared to rich-burn designs, although in some engines the BSFC increases. An engine's response to increases in load is adversely affected by [LEC], which may make this control technique unsuitable for some installations, such as stand-alone power generation applications. The effect on CO and HC emissions is a slight increase in most engine designs.[84]

LEC NOx Removal Efficiency:	*87%*
Controlled NOx Emission Rates:	*1-2 g/hp-hr*
	70 to 140 ppmv

[81] EPA, Final Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Docket ID EPA-HQ-OAR-2015-0500-0508, Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance, August 2016, Appendix A at 5-3, *available at:* https://www.regulations.gov/document?D=EPA-HQ-OAR-2015-0500-0508 [hereinafter referred to as "2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls"].
[82] EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-3.
[83] *Id.* at 4-12.
[84] EPA 1993 Alternative Control Techniques Document for RICE.

In its Updated Information on NOx Emissions and Control Techniques Document for RICE, EPA states the following test data for LEC:

> In all, the sources of NOx emission test data [] include the results of 476 individual tests conducted on 58 engines. (This count does not include the aggregated data in some of the sources discussed [], such as the May 2000 EPA memo and the AP-42 sections.) In these tests, NOx emissions ranged from 0.1 g/bhp-hr to 4.8 g/bhp-hr. Ninety-seven percent of these tests (460) found emissions less than or equal to 2 g/bhp-hr. Almost 75 percent (356) of the tests found emissions less than or equal to 1 g/bhp-hr, and 25 percent (120) found emissions of less than or equal to 0.5 g/bhp-hr. Only two tests measured NOx emissions greater than or equal to 4 g/bhp-hr.[85]

EPA also indicates that, "LEC is expected to be the most common control method for meeting the [1991 CARB Best Available Retrofit Control Technology (BARCT) for Stationary IC Engines], although SCR may be used as an alternative if LEC is unsuitable for a particular model engine."[86]

And according to the Interstate Natural Gas Association of America (INGAA), "LEC is the preferred approach to reduce lean-burn engine NOx emissions, but EPA or states may consider additional controls such as selective catalytic reduction (SCR)."[87]

EPA further states in its Updated Information on NOx Emissions and Control Techniques for RICE:

> Low-emission combustion retrofit equipment and services are generally available, particularly for the most plentiful engine models. Cooper Energy Services, maker of Cooper-Bessemer, Ajax, Superior, and Delaval engines provides CleanBurn™ retrofits for all of its larger models and offers these services for engines manufactured by other companies, as well. Dresser-Rand, manufacturer of Ingersoll-Rand, Clark, and Worthington engines also offers retrofit services for its lean-burn engines. The Waukesha Engine Division of Dresser Industries manufactures two engine families that are available either in rich-burn or LEC configurations. The company offers LEC retrofit services for those engines originally sold in the rich-burn configuration. At least three third-party vendors (Diesel Supply Company; Enginuity, Inc.; and Emissions Plus, Inc.) offer retrofit services for a wide variety of engine makes and models. These vendors will work with any model engine, although economies of scale can reduce capital costs for plentiful engines. For other engines, customized precombustion chambers can result in somewhat higher costs.[88]

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[85] EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-9.
[86] *Id.* at 4-11.
[87] INGAA, Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry (July 2014), *available at*: https://www.ingaa.org/File.aspx?id=22780.
[88] EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-4.

California Air Districts have long been regulating NOx emissions from RICE, including lean-burn RICE. CARB issued guidance to Air Districts in 2001 on the reasonably available control technologies (RACT) and the best available retrofit control technologies (BARCT) for controlling NOx emissions from a broad range of stationary RICE.[89] In its analysis, CARB determined that LEC was a RACT level of control, and CARB set a NOx RACT limit of 125 ppmv.[90] CARB established a BARCT NOx limit for two- and four-stroke lean-burn engines rated at or higher than 100 hp of 65 ppmv or 90% reduction in NOx emissions.[91] CARB indicated that this lower NOx BARCT limit could also be met with LEC for many engines, although some engines might require some supplemental measures such as ignition system modifications and engine derating and others might require SCR to meet the BARCT NOx limit.[92] LEC can achieve 80 to 90% NOx reductions or even higher.[93]

The only exemptions CARB proposed from the NOx BARCT limit were for lean-burn engines rated less than 100 hp. With respect to these smaller engines, CARB determined that there are a relatively small number of such two-stroke lean-burn engines that cannot cost effectively install LEC or other NOx controls necessary to meet the NOx limits set for lean-burn RICE (both RACT and BARCT limits).[94] CARB described these engines as "located in gas fields statewide and [] used to drive compressors at gas wells."[95] CARB determined that, "the only cost effective way to control emissions from the[se] small two-stroke engines is by properly maintaining and tuning these engines which includes replacing oil-bath air filters with dry units and periodically cleaning the air/fuel mixer and muffler."[96] CARB ultimately recommend that the air districts, "require the replacement of these engines at the end of the two-stroke engine's useful life with prime movers having lower NOx emissions."[97]

CARB conducted cost effectiveness analyses for LEC on lean-burn RICE at a wide variety of engine power output ratings. CARB's analyses of capital and annual operating costs for retrofitting existing engines with LEC (and other NOx controls) were based on, "a mixture of quotes and extrapolations of cost from information provided by industry sources, associations, local governments, and the U. S. EPA."[98] CARB's cost data for LEC are presented in the table below.

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[89] CARB 2001 Guidance.
[90] *Id.* at IV-6.
[91] *Id.* at IV.9.
[92] *Id.* at II-2, IV-10.
[93] EPA has said NOx reductions with LEC could be as high as 93%. *See* EPA's 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032) at 5-67.
[94] *Id.* at II-2.
[95] *Id.* at IV-7.
[96] *Id.*
[97] *Id.*
[98] *Id*. at V-2.

Table 8. Capital Costs of LEC, 2001$[99]

POWER OUTPUT (hp)	LEC CAPITAL COSTS
50-150	$14,000
151-300	$24,000
301-500	$42,000
501-1,000	$63,000
1,001-1,500	$148,000

CARB calculated cost effectiveness for LEC assuming 80% NOx control, a 10-year life of the controls, and a 10% interest rate.[100] As previously discussed, to be consistent with EPA's Control Cost Manual which recommends the use of the bank prime interest rate, it is more appropriate to use a lower interest rate of 5.5%.[101] Thus, the CARB LEC cost data were revised to be consistent with the EPA's Control Cost Manual in assuming a 5.5% interest rate in amortizing the capital costs. It must be noted that CARB's assumed 10-year life of LEC controls seems unreasonably short, as EPA has assumed a 15-year life of all controls for stationary internal combustion engines in other cost analyses.[102] Thus, the CARB LEC cost data were revised to assume a 15-year life of LEC controls.

CARB's cost analysis also assumed that the engines are run at rated power (100% load) for only 2,000 hours annually, which is equivalent to a capacity factor of roughly 25%. To reflect the cost effectiveness values for a range of operating hours, CARB's cost analysis was revised to reflect costs at 91% capacity factor, or 8,000 operating hours per year.

Last, CARB's cost effectiveness analysis only assumed an 80% NOx removal efficiency with LEC. As discussed above, an 80% NOx control efficiency is the low-end of NOx removal rates that can be achieved with LEC at lean-burn engines. CARB's BARCT limit is based on 90% NOx reduction. Thus, CARB's cost analyses were also revised to include cost effectiveness for 90% NOx control as well as 80% NOx control. These revised cost effectiveness calculations—assuming a 5.5% interest rate, 15-year life of LEC, capacity factors of 2,000 operating hours and of 8,000 operating hours, and both 80% NOx control and 90% NOx control—are presented in Table 9 below.

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[99] *Id.* Note that the cost basis is not identified, and it is assumed to be 2001 dollars based on the date of the analysis. Also note that for engines with power output of 1,001-1,500 hp, a mid-range cost of $148,000 was assumed, similar to the assumption made by EPA when using CARB's cost data in its 2016 CSAPR TSD.
[100] CARB 2001 Guidance at V-4.
[101] *See, e.g.*, https://fred.stlouisfed.org/series/DPRIME.
[102] EPA, Regulatory Impact Analysis for the NOx SIP Call, IP, and Section 126 Petitions, September 1998, at 5-5 (Table 5-3).

Table 9. Cost Effectiveness to Reduce NOx Emissions by 80%–90% from Lean-Burn RICE with LEC Operating at 2,000 and 8,000 Hours per Year[103]

ENGINE TYPE	SIZE, hp	ANNUALIZED COSTS OF LEC, 2001$	COST EFFECTIVENESS OF LEC TO REDUCE NOx BY 80%–90%, 2,000 HOURS/YEAR, 2001$	COST EFFECTIVENESS OF LEC TO REDUCE NOx BY 80%–90%, 8,000 HOURS/YEAR, 2001$
LEAN-BURN	50	$1,857	$941/ton-$837/ton	$235/ton-$209/ton
	200	$3,184	$403/ton-$359/ton	$101/ton-$90/ton
	500	$5,572	$282/ton-$251/ton	$71/ton-$63/ton
	1,000	$8,358	$212/ton-$188/ton	$53/ton-$47/ton
	1,500	$19,635	$332/ton-$295/ton	$83/ton-$74/ton

The above analyses demonstrate that, with the exception of lean-burn engines rated at 50 hp that only operated 2,000 hours per year, the cost effectiveness of LEC at lean-burn engines is essentially between $80–$400/ton for a wide range of engine sizes and a wide range of operating hours.

In its Technical Support Document for Non-EGU NOx emissions for the CSAPR rule, EPA presented an equation for estimating the capital cost of LEC on natural gas lean-burn engines, based on cost calculations for engines of varying size and annual capacity factor from CARB's 2001 Guidance:[104]

$$\text{Capital cost} = \$16{,}019\ e^{0.0016 \times (hp)}$$

Thus, the above equation can be used to estimate capital costs for LEC based on the hp rating of the unit. CARB did not identify any operating expenses with LEC, and thus the appropriate capital recovery factor can be multiplied by the results of the equation above for any size lean-burn engine to estimate annual costs of control with LEC.

CARB's cost estimates for LEC are relatively consistent with EPA's prior cost analyses of LEC lean-burn engines. For example, EPA's 1993 Control Techniques Document for RICE found the cost effectiveness for medium-speed engines operating at a 91% capacity factor was in the range of $310–$590/ton (1993$, assuming a 7% interest rate and a 15-year life).[105] EPA subsequently updated the cost information on LEC technology for lean-burn SI engines because "developments in LEC technology have brought retrofit costs down in recent years."[106] Specifically, in EPA's Updated Information on NOx

[103] Cost information for LEC from CARB 2001 Guidance at Tables V-1 and V-2. Annualized cost of control assumed a capital recovery factor of 0.099626 (assuming a 15-year life of controls and a 5.5% interest rate). Uncontrolled NOx emissions are based on EPA's 1993 Alternative Control Techniques for RICE (EPA-453/R-93-032).
[104] 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 5-5. Note that the CSAPR TSD also presented an equation for annual costs, but it reflected annualized capital costs assuming a 7% interest rate and a 10-year life. Thus, the annualized cost equation is not provided here because it is not reflective of the current recommended interest rate for cost calculations of 5.5% or a 15-year life of controls.
[105] *See* EPA 1993 Alternative Control Techniques Document for RICE, Table 2-13 at 2-36.
[106] EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-33.

Emissions and Control Techniques for RICE, its analysis of LEC retrofit for lean-burn SI engines showed, "cost effectiveness below $500 per ton of NOx reduced [in 1997$] for all engines larger than 2,000 bhp," which reflected an 80% capacity factor, 88% control, and a 7% interest rate. [107]

The 2001 CARB cost analyses for LEC is the most current comprehensive analyses for the costs of LEC available. It is recommended that the CARB cost data, as reflected in the equation given above (from EPA's CSAPR TSD), be used to calculate capital costs based on horsepower rating of an engine, assuming a 15-year life, 5.5% interest rate, and 90% NOx control. CARB's BARCT NOx limit of 125 ppmv should be considered as an achievable NOx emission limit with LEC at a lean-burn engine.

<u>Application of LEC to lean-burn RICE is cost effective for a wide range of engine sizes and types.</u>

While the cost estimates and cost algorithms in this section are of a cost basis that is close to twenty years old, it is important to note that, from at least 2001, several state and local air agencies have found that the costs of control to achieve NOx emission rates reflective of LEC at lean-burn engines (<2 g/bhp-hr (150 ppmv)) have been considered as cost effective to require such a level of control on existing lean-burn RICE over 100 hp. This will be discussed further in Section II.G. below. For the reasons previously discussed in this report, it is not possible to accurately escalate these costs from 2001 to a current dollar basis. Nonetheless, the fact that numerous state and local agencies have imposed NOx limits that reflect the application of LEC demonstrates that it is a control that has been extensively retrofitted to existing lean-burn engines.

The environmental and energy impacts of LEC for lean-burn RICE are minimal and include the following:

- A decrease in fuel consumption of 0 to 5% resulting in decreased CO_2 emissions, as well as a corresponding decrease in emissions of other air pollutants[108]
- No effect on power output.[109]

E. LEAN-BURN RICE: SELECTIVE CATALYTIC REDUCTION (SCR)

Selective catalytic reduction (SCR) is an add-on (post combustion) NOx reduction technology that has been in use as early as the 1970s and has been applied to numerous source categories including stationary RICE units. In its 1993 Alternative Control Techniques Document for Stationary RICE, EPA described SCR systems as follows:

> Selective catalytic reduction is an add-on control technique that injects ammonia (NH3) into the exhaust, which reacts with NOx to form N2 and H20 in the catalyst reactor. The two primary catalyst formulations are base-metal (usually vanadium pentoxide) and zeolite. Spent catalysts containing vanadium pentoxide may be considered a hazardous material in some areas, requiring special disposal considerations. Zeolite catalyst formulations do not contain hazardous materials.

[107] *Id.* at 5-9.
[108] *See* EPA 1993 Alternative Control Techniques Document for RICE, Table 2-7 at 2-15.
[109] *Id.*

> Selective catalytic reduction applies to all lean-burn SI engines and can be retrofit to existing installations except where physical space constraints may exist. There is limited operating experience to date, however, with these engines. A total of 23 SCR installations with lean-burn SI engines were identified in the United States from information provided by catalyst vendors, in addition to over 40 overseas installations. To date [1993] there is also little experience with SCR in variable load applications due to ammonia injection control limitations. Several vendors cite the availability of injection systems, however, designed to operate in variable load applications. Injection systems are available for either anhydrous or aqueous ammonia. As is the case for NSCR catalysts, fuels other than pipeline-quality natural gas may contain contaminants that mask or poison the catalyst, which can render the catalyst ineffective in reducing NOx emissions. Catalyst vendors typically guarantee a 90 percent NOx reduction efficiency for natural gas-fired applications, with an ammonia slip level of 10 ppm or less. One vendor offers a NOx reduction guarantee of 95 percent for gas- fired installations. Based on an average uncontrolled NOx emission level of 16.8 g/hp-hr (1,230 ppmv), the expected controlled NOx emission level is 1.7 g/hp-hr (125 ppmv). Emission test data show NOx reduction efficiencies of approximately 65 to 95 percent for existing installations. Ammonia slip levels were available only for a limited number of installations for manually adjusted ammonia injection control systems and ranged from 20 to 30 ppmv. Carbon monoxide and HC emission levels are not affected by implementing SCR. The engine BSFC increases slightly due to the backpressure on the engine caused by the catalyst reactor.[110]

There have been many advances in SCR systems and catalysts since EPA's 1993 Alternative Control Techniques Document. In 2012, the Ozone Transport Commission (OTC) issued a Technical Information Document on significant stationary sources of NOx emissions in the Oil and Gas Sector (hereinafter referred to as the "2012 OTC Report").[111] The OTC is a multi-state organization created under the CAA to address ozone problems in the Northeast and Mid-Atlantic U.S.[112] According to the 2012 OTC Report, many of the issues with variable load operation have been addressed by catalysts that have been designed to operate over a wide range of exhaust temperatures and for combustion devices with variable loads.[113] For example, in the 2012 OTC Report,[114] several vendors were listed that could provide such SCR systems and catalysts effective for the NOx control issues of lean-burn engines, such as Johnson Matthey,[115] Miratech Corporation which offers an SCR system for lean-burn engines used in natural gas compression,[116] CleanAir Systems which offers a lean-burn SCR called "E-Pod SCR" that is advertised to achieve up to 95% NOx reduction and reduce particulates, HC, and CO[117], and Caterpillar

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[110] EPA 1993 Alternative Control Techniques Document for RICE.
[111] *See* Ozone Transport Commission, Technical Information, Oil and Gas Sector, Significant Stationary Sources of NOx Emissions, Final, October 17, 2012, *available at*: https://otcair.org/upload/Documents/Meeting%20Materials/Final%20Oil%20%20Gas%20Sector%20TSD%2010-17-12.pdf.
[112] *See* https://otcair.org/about.asp.
[113] *See* 2012 OTC Report at 25-26.
[114] *Id.* at 26-27.
[115] *See* https://matthey.com/en/products-and-services/emission-control-technologies/mobile-emissions-control/selective-catalytic-reaction.
[116] *See* https://www.miratechcorp.com/products/cbl/.
[117] *See* http://intermountainelectronics.com/uploads/media/Media_633929646982817973.pdf.

which offers SCR systems for several of its engines.[118] Although EPA's 1993 Alternative Control Techniques Document indicates achievable NOx emission rates of 1.7 g/hp-hr, the OTC identified NOx rates achievable with SCR at lean-burn engines of 0.2 to 1.0 g/bhp-hr, with the lower NOx rates achievable at four-stroke lean-burn engines and/or engines that also have some combustion control upgrades.[119] Moreover, two air districts in California—South Coast Air Quality Management District (SCAQMD) and SJVAPCD—have adopted NOx emission limits of 11 ppmv, which equates to 0.15 g/hp-hr, for lean-burn engines.[120] Based on this more recent information, the NOx reduction efficiency and achievable NOx emission rates are:

- *NOx Removal Efficiency:* *90-95+%*
- *Controlled NOx Emission Rates:* *0.15 to 1.0 g/hp-hr (11 to 73 ppmv)*

SCR can be applied to lean-burn spark-ignition engines, diesel compression-ignition engines, and dual-fuel compression-ignition engines. And while diesel engines are the most prevalent applications of SCR at RICE units, SCR has also been applied at lean-burn spark-ignition engines fired with natural gas, including at natural gas pipeline compressor stations.[121] Outside of the U.S., EPA stated in its 2000 update that "there are over 700 IC engines controlled with SCR systems in Europe and Japan, including approximately 80 to 100 2-stroke engines."[122] Thus, for those engines for which effective LEC retrofits are not available, SCR is available to achieve high levels of NOx control.

As previously stated, CARB issued guidance to California Air Districts in 2001 on the best available retrofit technologies for controlling NOx emissions from a broad range of stationary RICE.[123] For two- and four-stroke lean-burn engines greater than 100 hp, CARB set a BARCT limit 65 ppmv or 90% reduction in NO_x emissions.[124] CARB indicated that "[i]t is expected that the most common control method used to meet the BARCT emission limit [] will be the retrofit of low-emission combustion controls. Other techniques may also be used to supplement these retrofits, such as ignition system modifications and engine derating. For engines that do not have low-emission combustion modification

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[118] *See* https://www.cat.com/en_GB/search/search-results.html?search=selective+catalytic+reduction&pagePath=%252Fcontent%252Fcatdotcom%252Fen_GB%252Fproducts%252Fnew%252Fpower-systems%252Foil-and-gas.

[119] *See* 2012 OTC Report at 27-28 and 40-41.

[120] *See* SQAQMD Rule 1110.2, Table I and SJVAPCD Rule 4702, Table 2. The SCAQMD 11 ppmv limit applies to engines at facilities that are not in the Regional Clean Air Incentives Market (RECLAIM) as of January 5, 2018, and SCAQMD has indicated there are 18 engines currently meeting the 11 ppmv limit. *See* http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1110.2/par1110-2-wg2-final.pdf?sfvrsn=6 at Slide 32. The SJVAPCD 11 ppmv limit does not apply to lean-burn engines used for gas compression, or those engines of limited use operation (less than 4,000 hours per year), or those engines that are waste gas-fuel—a higher limit of 65 ppmv applies to these engines.

[121] *See, e.g.,* EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-13.

[122] *Id.* at 4-13 (EPA notes, "[f]rom the context, we believe that the source of this last data meant 2-stroke lean-burn SI engines fired with natural gas, although it is not explicit in the reference.").

[123] *See* CARB 2001 Guidance.

[124] *Id.*

kits available, SCR may be used as an alternative to achieve the BARCT emission limits."[125] Thus, CARB envisioned that some RICE units would need to install SCR.

The SJVAPCD requires that emissions from lean-burn RICE meet the following NOx limits:

Table 10. SJVAPCD NOx Emission Limits for All Lean-Burn Non-Agricultural Operations Engines[126]

ENGINE TYPE		NOx LIMIT [ppmvd corrected to 15% O2]	EQUIVALENT NOx LIMIT [g/bhp-hr]
2SLB	Gaseous Fueled; >50 hp and <100 hp	75	1.0
4SLB	Limited Use	65	0.9
	Used for gas compression	65 or 93% reduction	0.9
	All other	11	0.15

TABLE NOTES:

- Conversions to g/bhp-hr limits are based on EPA's Stationary Reciprocating Internal Combustion Engines Updated Information on NOx Emissions and Control Techniques (September 2000), where the conversion for uncontrolled lean-burn engines and lean-burn engines controlled with SCR is: 73 ppmv = 1 g/bhp-hr

The 11 ppmv limit is clearly more stringent than CARB's recommended BARCT limit and thus presumably requires SCR to achieve at lean-burn RICE, possibly along with combustion modifications. SCAQMD adopted an 11 ppmv NOx limit for all RICE units unless located at a Regional Clean Air Incentives Market (RECLAIM) Facility, and thus SCAQMD has applied this lower NOx limit more broadly than the SJVAPCD.

The SJVAPCD completed a cost effectiveness analysis for the emission limits in the above table in 2003.[127] The District analyzed a broad array of control scenarios including installing SCR on lean-burn RICE of wide-ranging power output and capacity utilization and multiple applications (e.g., limited use, gas compression, etc.). SJVAPCD's report indicated that "[d]istrict staff feels that the annual compliance costs are reasonable for [all] five cases analyzed [including installation of a SCR system for a lean-burn engine]."[128] The report further concluded that "[a]lthough a few of the results indicated a high cost effectiveness, such results are due to the low emission reductions and not from high annual costs."[129]

SJVAPCD used the capital and annual operating costs for retrofitting existing engines with SCR based on CARB's 2001 guidance—which are based on installation of the more advanced parametric emissions

[125] *Id.*
[126] SJVAPCD Rule 4702 Internal Combustion Engines, *available at*: https://www.valleyair.org/rules/currntrules/r4702.pdf.
[127] SJVAPCD Rule 4702 Cost Effectiveness Analysis (July 17, 2003), *available at*: https://ww3.arb.ca.gov/pm/pmmeasures/ceffect/reports/sjvapcd_4702_report.pdf.
[128] *Id.* at B-2.
[129] *Id.*

monitoring systems (PEMS) feedforward system controls, the use of urea as the reducing agent, and a catalyst sized to achieve 96% reduction in NOx emissions—as presented in the table below.

Table 11. Capital and Operating Costs of SCR[130]

POWER OUTPUT (hp)	INSTALLED SCR CAPITAL COSTS, 1999$	ANNUAL OPERATING AND MAINTENANCE COSTS, 1999$
50	$45,000	$20,102
200	$45,000	$26,102
500	$60,000	$35,102
1,000	$149,000	$78,102
1,500	$185,000	$117,102

TABLE NOTES:

- The cost for the SCR is based on urea injection, with PEMS, and catalyst sized for 96% NOx conversion.

SJVAPCD determined the annualized costs of control assuming a 10-year life of controls and a 10% interest rate.[131] As previously discussed, to be consistent with EPA's Control Cost Manual, a lower interest rate of 5.5% should be used for current cost effectiveness calculations.[132] With respect to the SCR equipment life, SCR systems can likely last much longer than 15 years. EPA states that SCRs at boilers, refineries, industrial boilers, etc. have a useful life of 20-30 years.[133] To be consistent with EPA's statements on SCR, this report will assume a 20-year life for SCRs at lean-burn engines. Thus, a 5.5% interest rate and 20-year life of controls has been used for the revised SCR cost calculations presented herein.

SJVAPCD presented the cost effectiveness of retrofitting RICE with SCR based on reducing NOx emissions from a NOx rate of 740 ppmv to the proposed (and ultimately adopted) emission limit of 65 ppmv, which reflects a 91% control efficiency across the SCR. For RICE not already meeting NOx limits of 740 ppmv, employing SCR to reduce NOx emissions from what EPA considers to be the uncontrolled NOx emission rate of 1,230 ppmv (16.8 g/bhp-hr) to 65 ppmv corresponds to a NOx emissions reduction efficiency of 95%.[134] Such removal rates are achievable with SCR at lean-burn RICE, as discussed above.[135] However, the lower NOx rate of 11 ppmv that SJVAPCD has adopted for lean-burn engines not

[130] *Id.* Table 5.
[131] *Id.* Table 2 and 3.
[132] EPA's Control Cost Manual recommends the prime lending rate be used to amortize capital costs, and the highest the bank prime rate has been in the past five years is 5.5%. *See, e.g.*, https://fred.stlouisfed.org/series/DPRIME.
[133] *See* EPA's Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 80.
[134] EPA 1993 Alternative Control Techniques Document for RICE, Table 2-1 at 2-3.
[135] *See*, *e.g.*, 2012 OTC Rep at 19.

used for compression and not operated at limited use (less than 4,000 hours per year) would also be achievable with SCR alone or with combustion controls plus SCR. A NOx limit of 11 ppmv reflects 99% control from uncontrolled levels.

SJVAPCD claimed to present cost effectiveness data for two different operating capacity factors: 25% and 75%. However, SJVAPCD also cited to CARB's cost analyses as the basis for SJVAPCD's assumed costs.[136] In the underlying cost effectiveness analysis, CARB assumed that the engines are run at rated power (100% load) for 2,000 hours annually, which is equivalent to a capacity factor of roughly 23%. It does not appear that SJVAPCD accounted for increased operating costs in its evaluation of costs at the higher capacity factor. Operating expenses at higher operating capacity factors would increase approximately by the ratio of the higher capacity factor (or operating hours) to the originally assumed capacity factor (or operating hours) in the original cost analysis.[137] The following table shows the cost effectiveness of retrofitting SCR to an uncontrolled lean-burn RICE operating at 2,000 hours per year and at 8,000 hours per year and meeting a 65 ppmv NO_x limit, based on a 20-year life and 5.5% interest rate. For the cost analyses shown in Table 12, SJVAPCD's operational costs were increased by a factor of four to more accurately reflect operational expenses at an operating capacity of 8,000 hours per year.

Table 12. Cost Effectiveness to Reduce NOx Emissions by 95% from 4SLB RICE with SCR Operating at 2,000 and 8,000 Hours per Year[138]

ENGINE TYPE	SIZE, hp	ANNUALIZED COSTS OF SCR, 1999$	COST EFFECTIVENESS OF SCR, 2,000 HOURS PER YEAR, 1999$	COST EFFECTIVENESS OF SCR, 8,000 HOURS PER YEAR, 1999$
4SLB	50	$24,585	$13,567/ton	$3,392/ton
	200	$30,585	$4,244/ton	$1,061/ton
	500	$41,080	$2,281/ton	$570/ton
	1,000	$92,946	$2,574/ton	$644/ton
	1,500	$135,533	$2,512/ton	$628/ton

As previously stated, the cost effectiveness presented in Table 12 above reflects compliance with the 65 ppmv NOx emission limit with SCR, which corresponds to a NOx emissions reduction efficiency of

[136] *See* SJVAPCD Rule 4702 Cost Effectiveness Analysis (July 17, 2003), Table 5, notes F and H.

[137] This is based on an analysis of varying hours of operation in EPA's SCR Cost Calculation Spreadsheet (06/2019) available on its Control Cost Manual website at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution. While this spreadsheet is designed to estimate costs of SCR for fossil fuel-fired boilers, it can be used to estimate the increased in operational costs with increases in operating hours for any SCR system given that the SCR components are the same whether for a gas-fired boiler or a gas-fired RICE unit.

[138] *See* SJVAPCD Rule 4702 Cost Effectiveness Analysis (July 17, 2003), Table 5. Annualized costs of control were calculated using a capital recovery factor of 0.083679 (assuming a 20-year life of controls and a 5.5% interest rate). NOx emission reductions are based on SJAPCD's assumed 91% removal efficiency. Uncontrolled NOx emissions are based on EPA's 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032).

95%.[139] However, the lower NOx rate of 11 ppmv that SJVAPCD has adopted for lean-burn engines not used for compression and not operated at limited use (less than 4,000 hours per year) would also be achievable with SCR alone or with combustion controls plus SCR. A NOx limit of 11 ppmv reflects 99% control from uncontrolled levels.

More recently, EPA's 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls developed the following cost equations for SCR on natural gas four-stroke lean-burn engines, based on cost calculations for engines of varying size and annual capacity factor from SJVAPCD's 2003 cost effectiveness analysis:

Capital cost = $107.1 x (hp) + $27,186

Annual cost = $83.64 x (hp) + $14,718

The annual cost equation given above includes capital costs amortized assuming a 7% interest, which as discussed above is too high, and a 10-year equipment life, which should be 20 years as discussed above.[140] In the table below, the cost effectiveness of SCR based on these cost equations from EPA's 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls but revising the annual costs to reflect a 5.5% interest rate and a 20-year life of SCR and reflecting operations at 2,000 hours per year and at 8,000 hours per year. EPA's cost equations given above are based on an assumed 90% NOx reduction across the SCR, [141] so the same level of NOx control was assumed in the revised cost calculations presented in Table 13. Higher levels of NOx reduction and lower emission limits can be met with SCR alone or in combination with combustion controls. However, because higher levels of NOx reduction could also increase the operational expenses of SCR (unless some of the NOx reductions were achieved with combustion controls), the same 90% level of NOx control was assumed in the revised cost effectiveness analyses presented below to be consistent with the basis of EPA's cost equations.

[139] EPA 1993 Alternative Control Techniques Document for RICE, Table 2-1 at 2-3.
[140] *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 5-11 to 5-12.
[141] *Id.*

Table 13. Cost Effectiveness to Reduce NOx by 90% from 4SLB RICE with SCR Operating at 23% and 91% Capacity Factors, Based on EPA's 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls[142]

ENGINE TYPE	SIZE, hp	ANNUALIZED COSTS OF SCR, 2001$	COST EFFECTIVENESS OF SCR, 2,000 HOURS PER YEAR, 2001$	COST EFFECTIVENESS OF SCR, 8,000 HOURS PER YEAR, 2001$
4SLB	50	$17,509	$10,194/ton	$2,548/ton
	200	$29,368	$4,289/ton	$1,072/ton
	500	$53,086	$3,108/ton	$777/ton
	1,000	$92,617	$2,714/ton	$679/ton
	1,500	$132,148	$2,583/ton	$646/ton

Application of SCR to lean-burn RICE is cost effective for a wide range of engine sizes and types.

While the cost estimates and cost algorithms are of a cost basis that is twenty years old, the cost data have been relied on extensively.[143] And, from at least 2001, it is important to note that several state and local air agencies have found that the costs of control to achieve NOx emission limits of 1 g/bhp-hr (65 ppmvd) and even lower (as low as 11 ppmvd as required by SJVAPCD and SCAQMD) were cost effective to require such a level of control on existing lean-burn RICE rated greater than 100 hp. This will be discussed further in Section II.G. below. It is not possible to accurately escalate these costs to 2019 dollars. The CEPCI has been used extensively by EPA for escalating costs, but EPA states that using the CEPCI indices to escalate costs over a period longer than five years can lead to inaccuracies in price estimation.[144] Further, the prices of air pollution control do not always rise at the same level as price inflation rates. As air pollution control is required to be implemented more frequently over time, the costs of air pollution control often decrease due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc.

The environmental and energy impacts of SCR for lean-burn RICE include the following:

- 0.5% increase in fuel consumption resulting in increased CO_2 emissions
- 1 to 2% reduction in power output[145]

[142] *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 5-12. Note that EPA assumes the cost basis is 2001$. Annualized costs of control were calculated using a capital recovery factor of 0.083679 (assuming a 20-year life of controls and a 5.5% interest rate). Uncontrolled NOx emissions are based on EPA's 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032).

[143] EPA relied on the 2003 SJVAPCD Cost Effectiveness Analysis for Rule 4702 (which, in turn, relied on the 2001 CARB Guidance for Stationary SI Engines) in its 2016 EPA CSAPR TSD for Non-EGU NOx Emission Controls (Appendix A at 5-10 through 5-12).

[144] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, at 19.

[145] *See* EPA 1993 Alternative Control Techniques Document for RICE, Table 2-7 at 2-15.

- Increased solid waste disposal from spent catalysts[146]
- If ammonia is used instead of urea (which is assumed to be the reagent used in the SCR cost analyses presented above), there would be an increased need for risk management and implementation and associated costs.[147] If urea or aqueous ammonia is used as the reagent, the hazards from the use of pressurized anhydrous ammonia do not apply.

Regardless of these impacts, SCR technology is widely used at many industrial sources. There are typically not overarching non-air quality or energy concerns with this technology, and many of the concerns are addressed in the cost analysis.

In terms of length of time to install SCR at a lean-burn RICE unit, EPA has estimated that it takes 28–52 weeks to install SCR at a diesel-fired RICE unit.[148] It is reasonable to assume a similar time for the installation of SCR at a lean-burn natural gas-fired RICE unit.

F. RICE ELECTRIFICATION

Replacement of RICE with an electric motor is another pollution control option. In its 2001 guidance to California Air Districts, CARB indicated that electrification would be a NOx control option for RICE, with the potential to significantly reduce NOx emissions.[149] *Replacement of on-site engines with electric motors will reduce on-site NOx and other pollutant emissions by 100%.* Depending on the power source used for providing electricity to the site, air emissions may increase from the power generating site (i.e., if the power generating source is fueled by fossil fuels, rather than renewable energy such as wind or solar). However, even if the power is produced by a fossil fuel-fired power plant, it is likely more cost effective to a fossil fuel-fired power plant than it is to apply air pollution controls to individual engines.

CARB indicated in its 2001 guidance that "the majority of beam-balanced and crank-balanced oil pumps in California are driven by electric motors."[150] Thus, it stands to reason that electrification of such oil pumps is cost effective, given the widespread implementation.

CARB also found that electrification of RICE that fall within a size range from 50 to 500 hp would be a cost effective NOx control, but CARB stated that beyond the range of 50 to 500 hp, "modification and installation costs may become so extensive that this approach may not be cost effective."[151] However, on a cost per ton of NOx removed basis, CARB found that the electrification of engines in the 500 to 1,000 hp size range was as cost effective as the electrification of engines in the 50–150 hp size range –

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[146] *See* CDPHE RP for RICE at 10 (citing EPA (2002), EPA Air Pollution Control Cost Manual, 6th ed., EPA/452/B-02-001, EPA, Office of Air Quality Planning and Standards, RTP).
[147] Anhydrous ammonia is a gas at standard temperature and pressure, and so it is delivered and stored under pressure. It is also a hazardous material and typically requires special permits and procedures for transportation, handling, and storage. *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 15.
[148] 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls at 15.
[149] CARB 2001 Guidance at I-7.
[150] *Id.* at IV-2.
[151] *Id.* at V-2.

that is, $1,100/ton in 1999 dollars.[152] For engines in the size range of 150 to 500 hp, electrification of engines was somewhat more cost effective at $900/ton in 1999 dollars.[153] CARB indicated that Air Districts in California should consider the replacement of engines with electric motors as a control option "whenever it is feasible in order to maximize emission reductions."[154]

It is important to note that CARB's cost effectiveness calculations were based the assumption of only 2,000 hours per year operation, and CARB assumed capital costs would be amortized over a 10-year period and at a 10% interest rate.[155] There is no basis for assuming such a short lifespan for an electric internal combustion engine. As discussed further above, gas-fired RICE units have a useful life of at least 30 years, and many have been in operation much longer than 30 years.[156] Had CARB assumed a 30-year life of controls, the annualized cost of a new electric compressor over 30 years would be significantly lower than CARB's assessment of those costs over 10 years. Further, for an engine that operates more than 2,000 hours per year, replacement with an electric engine will reduce more NOx emissions, which would also make the replacement of an engine with an electric engine more cost effective.

More recently, EPA's Natural Gas STAR Program issued a Fact Sheet which evaluated the methane-reduction benefits of replacing gas-fired reciprocating compressors with electric compressors.[157] According to EPA, "[t]he EPA's Natural Gas STAR Program provides a framework for Partner companies within U.S. oil and gas operations to implement methane reducing technologies and practices and document their voluntary emission reduction activities."[158]

The Fact Sheet documents the costs of replacing five existing gas-fired reciprocating compressors with four electric compressors.[159] This Fact Sheet was made available in 2011, and thus the cost basis is assumed to be either from 2010 or 2011. Specifically, the Fact Sheet indicates that a partner replaced two 2,650 hp reciprocating compressors, two 4,684 reciprocating compressors, and one 893 hp reciprocating compressor with four 1,750 hp electric compressors.[160] The Fact Sheet states that the total cost of the replacement was $6,050,000, including the cost of the motor and compressor.[161] The Fact Sheet calculated the cost of electricity as the primary operating expense, and the electricity costs assuming continual operation of the compressors throughout the year were estimated to be $6,800,000

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[152] *Id.* at V-3.
[153] *Id.*
[154] *Id.* at VII-2.
[155] *Id.* at V-4 to V-4.
[156] *See*, *e.g.*, EPRI, 20 Power Companies Examine the Role of Reciprocating Internal Combustion Engines for the Grid, *available at*: https://eprijournal.com/start-your-engines/. The authors also note that, in reviewing permits for gas processing facilities and compressor stations in New Mexico, it is not uncommon to have engines that were constructed from the 1950s to 1970s still operating at such facilities.
[157] *See* EPA, Partner Reported Opportunities (PROs) for Reducing Methane Emissions, PRO Fact Sheet No. 103 Install Electric Compressors, 2011, *available at*: https://www.epa.gov/sites/production/files/2016-06/documents/installelectriccompressors.pdf.
[158] *See* https://www.epa.gov/natural-gas-star-program/natural-gas-star-program.
[159] *See* EPA, Partner Reported Opportunities (PROs) for Reducing Methane Emissions, PRO Fact Sheet No. 103 Install Electric Compressors, 2011.
[160] *Id.* at 2.
[161] *Id.*

per year.[162] For electric compressors that operated less than every hour of the year, these operating costs can be scaled back by multiplying the projected electricity cost for continual operation by the ratio of the number of hours operated per year to 8,760 hours per year. Maintenance costs were assumed to be approximately 10% of the capital costs, and the maintenance costs would be lower than apply to gas-fired engines.[163] The Fact Sheet also presents the fuel gas savings for not having to pay for the natural gas to fire the reciprocating compressors based on three prices for natural gas ($3.00 per thousand cubic feet (MCF) of gas, $5.00 per MCF, and $7.00 per MCF).[164] The amount of natural gas saved by changing to electric compressors was estimated to be 1,700,000 MCF, assuming continual (8,760 hours) operation throughout the year and 20% efficiency of the gas-fired reciprocating compressors.[165] Because this analysis was focused on reducing methane emissions, no calculations of cost effectiveness of this control was done for NOx or any other pollutant.

With these data, the cost effectiveness of replacing similar-sized existing reciprocating compressor engines with similar-sized electric compressor engines as a NOx control measure can be calculated. For these calculations, it is assumed that the existing gas-fired reciprocating compressor engines are uncontrolled for NOx and thus emitting NOx at 16.8 g/bhp-hr.[166] To reflect compressor engines operating at varying hours per year, cost effectiveness calculations were done for replacing compressor engines operating at 2,000 hours, 4,000 hours, and 8,000 hours per year. The capital costs of the new electric compressors were amortized over a 30-year expected life of the new electric compressor engines, assuming a 5.5% interest rate consistent with EPA's Control Cost Manual methodology. The results of this analysis are provided in Table 14 below.

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[162] *Id.* This assumed that the four 1,750 hp compressor engines had 50% efficiency, operated 8,760 hours per year, and electricity cost $0.075/kW-hr.

[163] *Id.*

[164] *Id.*

[165] *Id.* A heating value of natural gas of 1,020 British Thermal Units (BTU) per standard cubic feet (SCF) of gas was also assumed.

[166] *See* EPA 1993 Alternative Control Techniques Document for RICE, Table 2-1 at 2-3.

Table 14. NOx Cost Effectiveness to Replace Natural Gas-Fired RICE Units with Electric Compressor Engines[167]

	Costs at Operating Hours per Year (2011 $)		
	2,000 hours/yr	**4,000 hrs/yr**	**8,000 hrs/yr**
Annualized Capital Costs of New Electric Engines	$506,385	$506,385	$506,385
Annual Operating Costs of New Engines and Excluding Costs of Gas for Replaced Engines	$992,940	$1,380,880	$2,156,761
Total Annual Costs	$1,887,265	$1,887,265	$2,663,146
NOx Removed, tpy	542 tpy	1,084 tpy	2,168 tpy
NOx Cost Effectiveness at Stated Hours/Year	$2,766/ton	$1,741/ton	$1,228/ton

Assumptions

- Existing Gas-Fired Reciprocating Compressor Engines: 2–2,650 hp, 2–4,684 hp, 1–893 hp
- Replacement Electric Compressor Engines: 4–1,750 hp
- Efficiency of Existing Gas-Fired Engines: 20%
- Efficiency of Electric Engines: 50%
- 30 Year Life of Electric Engines, 5.5% Interest Rate
- Cost of Electricity: $0.075 per kilowatt-hour; Cost of Natural Gas: $3.00/MCF[168]
- Annual Maintenance Costs: 10% of Capital Costs of New Electric Engines

The above cost effectiveness analysis does not take into account the increased emissions that may occur from the electric power generation that will power the new electric compressor engines, which will depend on the source of that power for the new electric engines. If the energy is provided by renewable sources, there will be no NOx, greenhouse gas, or other air pollution increase associated with the energy production. To take into account the increase in NOx from a fossil fuel-fired power plant providing the electricity to the electric compressor engines, a high-end estimate of the increase in NOx from fossil-fuel fired power plant would mean that the switch to electric engines would result in an overall NOx emission reduction of about 97% of the NOx emitted by the gas-fired reciprocating compressor engines (i.e., a power plant providing the electricity for the new electric compressor engines might increase NOx by 15 to 59 tons per year depending on the hours of operation of the new electric compressor

[167] The basis for the capital and operating costs are from EPA's PRO Fact Sheet No. 103 Install Electric Compressors.
[168] The $3.00/MSCF estimated cost of natural gas may overestimate natural gas prices. The EIA reported the Henry Hub Spot Price for 2019 to be $2.66/MCF and has projected the cost to stay similar or decrease slightly in 2020-2021. However, the Henry Hub spot price was higher ($3.27/MCF) in 2018. Further, the EIA lists the 2019 Industrial Sector price of natural gas to be $3.90. It is not clear which of these two prices would apply, and thus the assumed $3.00/MCF price of natural gas is a middle ground between these two prices. *See* https://www.eia.gov/outlooks/steo/report/natgas.php.

engines).[169] From the perspective of cost effectiveness, the potential increase in NOx emissions from the power generating source would not significantly impact cost effectiveness of replacing gas-fired engines with electric engines.

The costs in Table 14 assume that the engines are located relatively close to the power grid and thus do not take into account any costs to bring electricity to the site. For a site that is not relatively close to the power grid, CARB estimated it could cost $5,000 to $10,000 (in 1999 dollars) to set up the site for electric motor operation and states that some utilities may waive or refund those costs if monthly energy usage matches the cost to connect to the grid.[170]

There are many benefits associated with replacing gas-fired reciprocating compressor engines with electric compressor engines. Those benefits include: [171]

- Reduced maintenance requirements and costs.
- Electric engines are more efficient than gas-fired engines.
- Lower noise levels with electric motors compared to gas-fired engines.
- No on-site emissions of other air pollutants.

An additional benefit of replacing gas-fired engines with electric engines is the greenhouse gas reductions that would be achieved. With renewable energy accounting for a larger share of electricity production over time, there could be significant reductions in greenhouse gases by using electrified engines powered by renewable energy. In the EPA's Natural Gas STAR Program Fact Sheet for electric compressors, the gas savings by electrifying the compressors is stated to be 32,800 MCF per year.[172] With that amount of gas not being combusted in the compressor engines and the power for the compressor engines being supplied by renewable energy, there would be a decrease in greenhouse gas emissions of almost 2,000 tons per year.[173] With electric compression engines used, there also will be less methane released from compressor blowdowns. Compressors must be taken offline at times due to emergency upsets and due to maintenance. As previously stated, the maintenance requirements with an electric compressor engine are significantly less with electric compressor engines.[174] It also seems likely that an electric engine would be less prone to upsets that cause the engine to go offline, compared to a gas-fired reciprocating engine. Moreover, with no gas used in the compressor engine, fugitive emission leaks due to fuel gas are also eliminated. EPA's Natural Gas STAR Program Fact Sheet provided an estimate that methane emissions savings from replacing the five gas-fired compressor engines with electric engines could be as high as 16,000 MCF per year, based on a methane emission factor of 2.11

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[169] A NOx rate of 1.4 pounds per megawatt-hour was assumed for these calculations to represent a high-end estimate of the increase in NOx emissions if a fossil fuel-fired power plant provided the electricity for the electric engines. This reflects a NOx limit of 0.15 lb/MMBtu for a coal-fired power plant, which reflects a plant burning subbituminous coal with combustion controls. A natural gas-fired power plant would likely have a lower NOx rate, particularly if equipped with SCR.
[170] CARB 2001 Guidance at V-2.
[171] *See* EPA, PRO Fact Sheet No. 103 Install Electric Compressors at 2.
[172] *Id.* at 1.
[173] Calculated based on EPA's greenhouse gas emission factors for natural gas combustion in Table C-1 of Subpart C of 40 C.F.R. Part 98.
[174] *See* EPA, PRO Fact Sheet No. 103 Install Electric Compressors at 2.

MCF per horsepower.[175] Using the 100-year global warming potential identified by EPA,[176] that equates to roughly 10,000 tons per year of CO_2 equivalent emissions that would be avoided with no natural gas releases due to blowdowns with electric compressor engines. Thus, the total CO_2 equivalent emissions that could be reduced by replacing the five gas-fired engines with electric compressors powered with renewable energy would be about 12,000 tons per year.

There are several examples of electric engines being used in the oil and gas industry for compression, both at the wellhead and in compressor stations,[177] for drill rigs,[178] and in oil pumps.[179] Ambient air quality concerns have typically been the driver for electrification of engines in the past. Electrification of RICE units can be a very cost effective way to eliminate NOx and other air emissions, including greenhouse gas emissions, for the oil and gas industry and thus should be given serious consideration as an effective pollution control to address regional haze.

G. NOx EMISSION LIMITS THAT HAVE BEEN REQUIRED FOR EXISTING NATURAL GAS-FIRED STATIONARY RICE UNITS

The NSPS standards applicable to stationary spark ignition gas-fired RICE units were last reviewed and revised in 2008.[180] The most stringent NOx limit of those standards currently in effect for new and modified spark ignition RICE units is 1.0 g/hp-hr for rich burn engines greater than 100 hp and for lean-burn engines between 100 hp and 1,350 hp.[181] In considering reasonable progress controls for gas-fired spark-ignition RICE units, the applicable NSPS standards should be considered the "floor" of potential NOx controls to consider for an existing RICE unit.

Numerous states and local air agencies have adopted similar or more stringent NOx limits for existing spark-ignition gas-fired RICE units to meet, many of which have been in place for 10–20 years. In Table 15 below, we summarize those state and local air pollution requirements. Some of this information was initially obtained from EPA's 2016 CSAPR TSD,[182] which provided a summary of state NOx regulations for gas engines.[183] The current state/local requirements for those CSAPR states were confirmed by a review of the state and local rules. The CSAPR TSD focused on the rules applicable in the CSAPR states. A review of California Air District rules was also done for this report, because several of those air districts have adopted the most stringent NOx emission limitations for existing gas-fired engines. We reviewed many of the remaining states' regulations to determine whether there were NOx limitations for existing natural gas-fired stationary RICE units.

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[175] *Id.* at 1.
[176] *See* https://www.epa.gov/ghgemissions/understanding-global-warming-potentials#Learn%20why.
[177] Armendariz, Al, Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements, prepared for Environmental Defense Fund, January 26, 2009, at 29-30, *available at*: https://www.edf.org/sites/default/files/9235_Barnett_Shale_Report.pdf.
[178] *Id.* at 18.
[179] CARB 2001 Guidance at IV-2.
[180] *See* 40 C.F.R. Part 60, §60.4230(a)(5) and Subpart JJJJ. 73 Fed. Reg. 3568 (1/18/08).
[181] 40 C.F.R. Part 60, Subpart JJJJ, Table 1.
[182] *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix B at 14-15.
[183] *Id.*

Table 15 is a summary of the NOx emission limits required of existing gas-fired stationary RICE units in states and local air districts across the United States. It is important to note that these are limits that, unless otherwise noted, currently apply to existing RICE. Unlike the NSPS standards of 40 C.F.R. Part 60, Subpart JJJJ, the RICE did not have to be modified to trigger applicability to these emission limits. Instead, these emission limits apply to existing natural gas-fired stationary RICE units and generally required an air pollution control retrofit. These state and local NOx limits were most likely adopted to address nonattainment issues with the ozone NAAQS and possibly also the $PM_{2.5}$ NAAQS. However, Colorado adopted a NOx limit for lean-burn RICE of 1 g/hp-hr as part of its initial regional haze plan to achieve reasonable progress towards the national visibility goal.[184] Regardless of the reason for adopting the NOx emission limits, what becomes clear in this analysis is that numerous states and local governments have adopted NOx limitations that require NSCR at rich burn RICE units and either LEC or SCR at lean-burn RICE units. The lowest, most broadly applicable NOx limits are those recently adopted by SCAQMD which require gas-fired RICE units greater than 50 hp in size to meet a 11 ppmvd (equivalent to 0.15 g/hp-hr) NOx limit.

These limits were adopted generally to meet reasonably available control technology (RACT) and best available retrofit control technology (BARCT — applies in California), and costs are taken into account in making these RACT and BARCT determinations. However, RACT is not necessarily as stringent as BARCT. RACT is generally defined as: "devices, systems, process modifications, or other apparatus or techniques that are reasonably available taking into account: (1) The necessity of imposing such controls in order to attain and maintain a national ambient air quality standard; (2) The social, environmental, and economic impact of such controls."[185] BARCT, on the other hand, is defined as "an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source."[186] BARCT is like a best available control technology (BACT) determination under the federal prevention of significant deterioration (PSD) program, but it evaluates controls to be retrofit to existing sources, rather than applying to new or modified sources.

Table 15. State/Local Air Agency RICE Rules for Natural Gas-fired Stationary RICE Units[187]

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
CA-Antelope Valley AQMD[188]	Rule 1110.2	Both	50–500 hp	45 ppmvd (0.67 g/hp-hr (RB) or 0.62 g/hp-hr (LB))
			>500	36 ppmvd (0.54 g/hp-hr (RB) or 0.49 g/hp-hr (LB))

[184] *See* CDPHE RP for RICE at 10.
[185] 40 C.F.R. § 51.100(o).
[186] HSC Code § 40406 (California Code), *available at*: https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=40406.&lawCode=HSC.
[187] This table attempts to summarize the requirements and emission limits of State and Local Air Agency rules, but the authors recommend that readers check each specific rule for the details of how the rule applies to RICE units, and in case of any errors in this table.
[188] https://ww3.arb.ca.gov/drdb/av/curhtml/r1110-2.pdf.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
			Portable	80 ppmvd (1.19 g/hp-hr (RB) or 1.10 g/hp-hr (LB))
CA-Bay Area AQMD[189]	Reg. 9, Rule 8	RB	>50 bhp &/or not Low Usage (<100 hrs/yr) &/or not registered as portable	25 ppmv (0.37 g/hp-hr)
		LB	>50 bhp &/or not Low Usage (<100 hrs/yr) &/or not registered as portable	65 ppmv (0.89 g/hp-hr)
CA-Mojave Desert APCD[190]	Rule 1160[191]	RB	>500 bhp &/or >100 hours/4 quarters, and only if located in the Federal Ozone Nonattainment area	50 ppmv (0.75 g/hp-hr)
		LB		140 ppmv (1.92 g/hp-hr)
		RB		50 ppmv (0.75 g/hp-hr)
		LB		125 ppmv (1.71 g/hp-hr)
CA-Sacramento AQMD[192]	Rule 412	RB	>50 bhp & exemptions for 50-525 hp if low op hours (200-40 hrs)	25 ppmv (0.37 g/hp-hr) Alt Limit: 90% NOx Reduction
		LB	>50 bhp	65 ppmv (0.89 g/hp-hr) Alt Limit: 90% NOx reduction
CA-Santa Barbara AQMD[193]	Rule 333	RB	>50 bhp Noncyclically-loaded[194]	50 ppmvd (0.75 g/hp-hr) or 90% NOx reduction
		RB	>50 bhp	300 ppmvd (4.48 g/hp-hr)

[189] http://www.baaqmd.gov/~/media/dotgov/files/rules/reg-9-rule-8-nitrogen-oxides-and-carbon-monoxide-from-stationary-internal-combustion-engines/documents/rg0908.pdf?la=en.
[190] http://mdaqmd.ca.gov/home/showdocument?id=438.
[191] http://mdaqmd.ca.gov/home/showdocument?id=6631.
[192] http://www.airquality.org/ProgramCoordination/Documents/rule412.pdf.
[193] https://ww3.arb.ca.gov/drdb/sb/curhtml/r333.pdf.
[194] Noncyclically loaded means an engine that is not cyclically loaded. *See* Santa Barbara AQMD Rule 333.C.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
			Cyclically-loaded[195]	
		LB	>50 bhp & < 100 bhp	200 ppmvd (2.74 g/hp-hr)
		LB	≥100 bhp	125 ppmvd (1.71 g/hp-hr) or 80% NOx reduction
CA – San Diego AQMD[196]	Rule 69.4.1	RB	>50 bhp &>200 hrs/yr	25 ppmvd (0.37 g/hp-hr)
		LB	>50 bhp &>200 hrs/yr	65 ppmvd (0.89 g/hp-hr)
CA-San Joaquin Valley APCD[197]	Rule 4702	RB	>50 bhp, Cyclic loaded, Field Gas Fueled	50 ppmvd (0.75 g/hp-hr)
		RB	>50 bhp & <4,000 hrs/yr	25 ppmvd (0.37 g/hp-hr)
		RB	>50 bhp and all others (engines not waste gas-fueled or cyclic loaded or limited hours)	11 ppmvd (0.16 g/hp-hr)
		2SLB	>50 bhp & <100 bhp	75 ppmvd (1.03 g/hp-hr)
		LB	>50 bhp & <4,000 hrs/yr	65 ppmvd (0.89 g/hp-hr)
		LB	>50 bhp and used for gas compression	65 ppmvd (0.89 g/hp-hr) or 93% NOx reduction
		LB	>100 hp and not limited use (<4,000 hrs), not used for gas compression, or not waste-gas fueled	11 ppmvd (0.15 g/hp-hr)
	Rule 431	RB	>50bhp &>200 hrs/yr	50 ppmvd (0.75 g/hp-hr)

[195] "Cyclically-loaded" means "an engine that under normal operating conditions has an external load that varies by 40% or more of rated brake horsepower during any load cycle or is used to power a well reciprocating pump including beam-balanced or crank-balanced pumps. Engines powering air-balanced pumps are noncyclically-loaded engines." *See* Santa Barbara AQMD Rule 333.C.

[196] https://www.sandiegocounty.gov/content/dam/sdc/apcd/PDF/Rules_and_Regulations/Prohibitions/APCD_R69-4-1.pdf.

[197] https://ww3.arb.ca.gov/drdb/sju/curhtml/r4702.pdf.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
CA- San Luis Obispo APCD[198]				or 90% NOx Reduction
		LB	>50bhp &>200 hrs/yr	125 ppmvd (1.71 g/hp-hr) or 80% NOx Reduction
CA - SCAQMD[199]	Rules 1110.2 and 1100	RB & LB	>50 bhp	11 ppmvd (0.16 g/hp-hr (RB) 0.15 g/hp-hr (LB))
CA- Ventura County AQMD[200]	Rule 74.9	RB	>50 bhp & >200 hrs/yr	25 ppmvd (0.37 g/hp-hr) or 94% NOx reduction
		LB	>50 bhp & > 200 hrs/yr	45 ppmvd (0.62 g/hp-hr) or 90% NOx reduction
TX- Houston-Galveston-Brazoria Area[201]	30 TAC 117.2010(c)(2) Emission Specs for 8hr ozone demo	RB & LB	>50 hp	0.50 g/hp-hr (33 ppmvd (RB) 36 ppmv (LB))
TX- Dallas -Ft. Worth Area[202]	30 TAC 117.2110(1) Emission Specs for 8hr ozone demo	RB	>50 hp	0.50 g/hp-hr
		LB	In service before 6/1/07	0.70 g/hp-hr
		LB	Placed into service, modified, reconstructed, or relocated after 6/1/07	0.50 g/hp-hr
NJ[203]	Rule 7:27-19.8	RB	>500 bhp	1.5 g/bhp-hr
		LB	>500 bhp	2.5 g/bhp-hr

[198] https://ww3.arb.ca.gov/drdb/slo/curhtml/r431.pdf.
[199] http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1110-2.pdf.
[200] http://www.vcapcd.org/Rulebook/Reg4/RULE%2074.9.pdf.
[201] https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=117&rl=2010.
[202] http://txrules.elaws.us/rule/title30_chapter117_sec.117.2110.
[203] https://www.nj.gov/dep/aqm/currentrules/Sub19.pdf.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
		LB & used for generating electricity	≥148 kW	1.5 g/bhp-hr or 80% NOx reduction
		2SLB	≥200 bhp & <500 bhp	3.0 g/bhp-hr
		4SLB	≥200 bhp & <500 bhp	2.0 g/bhp-hr
		RB&LB	Constructed or modified after 3/7/07, engines used to generate electricity with output ≥37 kW	0.90 g/bhp-hr or 90% NOx reductions (for modified units)
NY[204]	6 CCR-NY 227-2.4 (f)	RB & LB	>200 bhp	1.5 g/bhp-hr
MA[205]	310 CMR 7.19:(8)(c)	RB	>3 MMBtu/hr and >1,000 hrs	1.5 g/bhp-hr
		LB	>3 MMBtu/hr and >1,000 hrs	3.0 g/bhp-hr
MD[206]	COMAR 26.11.29.02.C.	RB	RICE used to compress nat gas ≥2400 hp	110 ppmv (1.64 g/hp-hr)
		LB	RICE used to compress nat gas ≥2,400 hp	125 ppmv (1.71 g/hp-hr)
CT[207]	22a-174-22e(d)(6a)	RB	>3 MMBtu/hr, until 5/31/23 Beginning 6/1/23	2.5 g/bhp-hr 1.5 g/bhp-hr
		LB	>3 MMBtu/hr, until 5/31/23 Beginning 6/1/23	2.5 g/bhp-hr 1.5 g/bhp-hr
IL (Chicago are and Metro East area)[208]	Title 35 Part 217, § 217.388a)1)	RB	Applies to specific engines listed in App G and those >500 bhp	150 ppmv (2.24 g/hp-hr)

[204] https://govt.westlaw.com/nycrr/Document/I4e978e48cd1711dda432a117e6e0f345?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default).
[205] https://www.mass.gov/files/documents/2018/01/05/310cmr7.pdf.
[206] http://mdrules.elaws.us/comar/26.11.29.
[207] https://www.ct.gov/deep/lib/deep/air/regulations/20160114_draft_sec22e_dec2015(revised).pdf.
[208] http://www.epa.state.il.us/air/rules/rice/217-subpart-q.pdf.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
		LB except Worthington engines not listed in App G	Applies to specific engines listed in App G and >500 bhp	210 ppmv (2.88 g/hp-hr)
		LB Worthington engines not listed in App G	>500 bhp & >8 MMbhp-hrs	365 ppmv (5.0 g/hp-hr)
GA (45 county area – ozone)[209]	Rule 391-3-1-.02.(2)(mmm)	RB & LB	≥100kW&<25 MW, in operation <4/1/00	160 ppmv (2.19–2.39 g/hp-hr)
	Applies only to engines used to generate electricity	RB & LB	≥100k W&<25 MW, in operation >4/1/00	80 ppmv (1.10–1.19 g/hp-hr)
MI[210]	R 336.1818	RB	>1 ton/day NOx engines per avg ozone control period day in 1995	1.5 g/bhp-hr
		LB		3.0 g/bhp-hr
CO[211]	Reg. No 7, Sections XVIII.E. 2 and 3	RB	>500 hp constructed before 2/1/09	Install and operate both a NSCR and an AFRC by 7/1/2010
		RB or LB constructed or relocated to Colorado ≥1/1/11	≥100 hp & <500 hp	1.0 g/hp-hr
		RB or LB constructed or relocated ≥7/1/10	≥500 hp	1.0 g/hp-hr
MT[212]	ARM 17.8.1603	RB engines at "oil and gas well facilities" (which does not include Compressor engines) which completed or modified	>85 bhp	Install and operate NSCR or its equivalent to control air emissions

[209] http://rules.sos.ga.gov/GAC/391-3-1-.02.
[210] https://www.michigan.gov/documents/deq/deq-aqd-air-rules-apc-part8_314769_7.pdf.
[211] https://www.colorado.gov/pacific/cdphe/aqcc-regs.
[212] https://deq.mt.gov/Portals/112/DEQAdmin/DIR/Documents/legal/Chapters/CH08-16.pdf.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
		>3/16/79 and facility PTE NOx >25 tpy		
UT[213]	R307-510	Gas-fired engine at a well site that began operations, installed new engines or made modifications to existing engines after 1/1/16	≥100 hp	1.0 g/hp-hr

Most stringent NOx Limit of State/Local Rules:

11 ppmvd (0.15–0.16 g/hp-hr) applicable to either rich-burn or lean-burn RICE units greater than 50 bhp

In addition to the state and local air agency rules requiring NOx emission limits that clearly reflect highly effective NOx controls, some states have BACT or similar requirements that are required of new or modified sources regardless of whether or not such sources or modifications are major and subject to the major source PSD permitting programs. In some cases, states have issued guidelines on what is essentially considered BACT for these non-PSD new and modified sources, in the form of guidance and/or general permit or permit by rule requirements for RICE units. Table 16 below summarizes some of these state requirements which, when imposed in a permit would become binding emission limits.

[213] https://rules.utah.gov/publicat/code/r307/r307-510.htm.

Table 16. Other NOx Limits Applicable to Natural Gas-fired Stationary RICE Units

State	Determination	Applicability [hp]	NOx Limits and Engine Type Applicability [RB, LB or BOTH]
NEW JERSEY[214]	State of the Art (SOTA) Emission Performance Levels	NO SIZE SPECIFIED	0.15 g/hp-hr (BOTH)[215]
PENNSYLVANIA [216]	Best Available Technology (BAT) Emission Limits for new SI RICE permitted on or after 8/8/18	≤100	1.0 g/hp-hr
		>100 TO ≤500	0.7 g/hp-hr (LB) 0.25 g/hp-hr (RB)[217]
		>500	0.5 g/hp-hr (LB) 0.2 g/hp-hr (RB)
		≥2,370	0.3 g/hp-hr uncontrolled (LB) **or** 0.05 g/hp-hr with control (LB)[218]
PENNSYLVANIA [219]	Best Available Technology (BAT) Emission Limits for existing SI RICE permitted on or after	≤100	2.0 g/hp-hr
		>100 TO ≤500	1.0 g/hp-hr (LB)

[214] NJ DEP State of the Art Manual for Reciprocating Internal Combustion Engines (2003), *available at*: https://www.state.nj.us/dep/aqpp/downloads/sota/sota13.pdf.

[215] Generally applied controls to meet State of the Art Emission Performance Levels:

Rich-burn: NSCR

Lean-burn: SCR or LEC

Basis: "In determining SOTA performance levels for RICE engines, permitting agencies, industry associations, manufacturers of RICE and manufacturers of emissions control equipment were contacted to obtain updated information on emissions and control technologies. Databases for recent permitted and tested engines from New Jersey, California and USEPA were reviewed." *Id.* at 8.

[216] PA TSD for the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A, 2700-PM-BAQ0268) And the Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5, 2700-PM-BAQ0267), FINAL June 2018. *See* Tables 8 and 9, *available at*: http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=8904.

[217] PA DEP determined that NSCR is required for all rich burn engines rated greater than or equal to 100 bhp. PA TSD for the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A, 2700-PM-BAQ0268) And the Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5, 2700-PM-BAQ0267), FINAL June 2018. *See* Appendix C at 75, *available at*: http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=8904.

[218] Lean-burn engines greater than or equal to 2,370 hp have a dual BAT: (1) engines with a NOx emission rate of 0.30 g/bhp-hr do not require SCR based on economic feasibility; and (2) engines with a NOx emission rate of 0.050 g/bhp-hr require SCR.

[219] *Id.*

State	Determination	Applicability [hp]	NOx Limits and Engine Type Applicability [RB, LB or BOTH]
	2/2/13 but prior to 8/8/18		0.25 g/hp-hr (RB)[220]
		>500	0.50 g/hp-hr (LB) 0.20 g/hp-hr RB)
PENNSYLVANIA [221]	Best Available Technology (BAT) Emission limits for existing SI RICE permitted prior to 2/2/13	<1,500	2.0 g/hp-hr
WYOMING[222]	Oil and Gas Production Facilities Permitting Guidance Applicable to Natural Gas-Fired Pumping Units	≤50 hp AND MEETS BACT	2.0 g/hp-hr
TEXAS[223]	Oil and Gas Handling and Production Facilities Standard Permit RB engines manufactured on or after 1/1/2011; LB engines manufactured on or after 7/1/2010	≥100 bhp (RB) ≥500 bhp (LB)	1 g/bhp-hr

And in addition to the state guidance and/or general permit or permit by rule requirements for RICE units listed in Table 16, BACT analyses completed for PSD permits also demonstrate the feasibility of controls. As an example, in Missouri, BACT for lean-burn RICE at the Mid-Kansas Electric Company, LLC's

[220] PA DEP determined that NSCR is required for all rich burn engines rated greater than or equal to 100 bhp. PA TSD for the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A, 2700-PM-BAQ0268) And the Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5, 2700-PM-BAQ0267), FINAL June 2018. *See* Appendix C at 75, *available at*: http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=8904.

[221] *Id.*

[222] WYDEQ Oil and Gas Production Facilities Permitting Guidance (last revised December 2018), *available at:* http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/FINAL_2018_Oil%20and%20Gas%20Guidance.pdf.

[223] TCEQ Air Quality Standard Permit for Oil and Gas Handling and Production Facilities (effective November 8, 2012), *available at:* https://www.tceq.texas.gov/assets/public/permitting/air/Announcements/oilgas-sp.pdf.

Rubart Station was determined to be SCR with a NOx BACT limit equivalent to 0.07 g/hp-hr for loads of 50% or higher.[224]

As Table 15 shows, twenty-three state and local air pollution control agencies have adopted NOx emission limits for existing gas-fired stationary RICE units that reflect the application of NSCR to rich-burn natural gas-fired RICE units greater than 50 hp and LEC and/or SCR for lean-burn natural gas-fired RICE units greater than 50 hp. These air agencies have thus found that the levels of NOx control listed in Table 15, including NOx limits as low as 11 ppmvd, are cost effective for existing natural gas-fired RICE units, providing relevant examples of one measure for states to consider in their second round haze plans to help make reasonable progress towards remedying existing visibility impairment. Further, several states have adopted essentially presumptive BACT NOx limits for new or modified RICE engines that are at least as stringent as the most stringent NSPS limit and/or apply to smaller units than the NSPS. The fact that these limits could apply to modified units means that the states consider retrofit controls to meet the emission limits in Table 15 above to be cost effective. Table 16 above also provides relevant examples of one measure for states to consider to prevent future impairment of visibility due to oil and gas development.

H. SUMMARY – NOx CONTROLS FOR EXISTING RICH-BURN AND LEAN-BURN NATURAL GAS-FIRED RICE

The above analyses and state/local rule data demonstrate that numerous state and local air agencies have found that NSCR is a cost effective NOx control for rich-burn natural gas-fired RICE units with costs ranging from $44/ton to $3,383/ton (2009$). NSCR not only reduces NOx, but can also be optimized with the use of an AFRC and an oxygen sensor to effectively reduce CO and HC and VOCs.

Further, numerous state and local air agencies have found that LEC is cost effective for lean-burn natural gas-fired RICE units with costs ranging from $74/ton to $941/ton (2001$). For the lowest NOx limit of 11 ppmvd applicable to lean-burn engines under rules adopted by SCAQMD and SJVAPCD, SCR was presumably necessary to meet these limits with costs ranging from $650 to $3,500 per ton of NOx removed or even higher for engines that operate 2,000 hours per year.

As states evaluate regulation of NOx emissions from natural gas-fired RICE units, there are several factors to consider, such as how the units are loaded (cyclically or not), operating capacity factor, and size. Nonetheless, given the numerous state and local NOx limits in Table 15 above that reflect operation of NSCR at rich-burn units and LEC or SCR at lean-burn units, these controls for rich-burn and lean-burn units rated at 50 hp or greater should generally be considered as cost effective measures available to make reasonable progress from natural gas-fired RICE units, given that similar sources have assumed similar costs of control to meet Clean Air Act requirements. NSCR has the added visibility benefit of reducing VOCs, as well as NOx.

[224] Prevention of Significant Deterioration Air Construction Permit Application for Mid-Kansas Electric Company, LLC Rubart Station (July 2012), *available at:* http://www.kdheks.gov/bar/midkanec/Mid-Kansas_Rubart_Station_PSD_Air_Permit_App_12_19_12.pdf.

It also must be recognized that it may be as or more cost effective for NOx control, and more beneficial for regional haze, to replace gas-fired RICE units with electric engines rather than install NOx pollution controls. Moreover, electric engines have numerous benefits that should be considered with regard to the energy and non-air impacts factor of a reasonable progress analysis. These additional benefits include reducing on-site emissions of all pollutants, reduced noise levels, more efficient operation and maintenance requirements (including less frequent maintenance required), and decreased methane emissions due to blowdowns because the electric engines do not require as frequent maintenance and do not have as many upsets. In addition, if the power for the electric engines can be derived from renewable energy sources, the greenhouse gas reductions can be very significant. Indeed, with renewable energy becoming an increasingly greater proportion of electricity generation and with coal-fired electricity generation being phased out, these added benefits of replacing gas-fired RICE units with electric engines should be considered in the four-factor analysis of controls. Electrification of engines may be less cost effective than some of the NOx controls evaluated above such as NSCR and LEC, but the potential added benefits with electric motors will likely weigh in favor of electrification as the most effective reasonable progress control for RICE.

III. CONTROL OF VOC EMISSIONS FROM NATURAL GAS-FIRED RICE

VOC emissions from natural gas-fired RICE units result from incomplete combustion. The same is true for CO emissions. The combustion conditions that favor lower NOx emission rates, such as lower temperature combustion, tend to result in less complete combustion and thus higher VOC as well as CO emission rates. In general, the emissions of VOCs from uncontrolled gas-fired RICE are of a lower magnitude compared to NOx emissions. A discussion of the pollution controls to reduce VOC emissions from these engines is provided below.

EPA's AP-42 Emission Factor documentation indicates that the uncontrolled VOC emission factors for natural gas-fired RICE in the range of 0.03 to 0.12 lb/MMBtu,[225] although it must be noted that EPA gives these emission factors a "C" rating. EPA's emission factor ratings indicate the reliability of the emissions factor, and a "C" rating reflects that "[t]ests are based on unproven or new methodology, or are lacking a significant amount of background information."[226] EPA also states that "actual emissions may vary considerably from the published emission factors due to variations in engine operating conditions."[227] That said, EPA's emission factors for uncontrolled VOCs are an order of magnitude lower than uncontrolled NOx emissions from RICE units. For that reason, this report focuses extensively on NOx emission controls for RICE units. However, there are emission controls feasible and implemented for VOCs from RICE units.

[225] EPA, AP-42, Section 3.2, Tables 3.2-1, 3.2-2, and 3.2-3, *available at*: https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s02.pdf.
[226] EPA AP-42, Introduction at 8-9.
[227] EPA, AP-42, Section 3.2 at 3.2-3.

VOC Controls for Lean-Burn RICE

For lean-burn natural gas-fired RICE, as well as natural gas-fired combustion turbines, the primary method available for reducing VOC emissions is the use of an oxidation catalyst. For rich-burn RICE, NSCR is the pollution control of choice to address VOCs, as its three-way catalyst generally reduces NOx, CO, and VOCs with proper operation, although an oxidation catalyst can be installed downstream of the NSCR to improve VOC control.

A 2015 report issued by the Manufacturers of Emission Controls Association on emission controls for stationary internal combustion engines states as follows regarding oxidation catalyst for lean-burn engines:[228]

> Oxidation catalysts (or two-way catalytic converters) are widely used on diesel engines and lean-burn gas engines to reduce hydrocarbon and carbon monoxide emissions. Specifically, oxidation catalysts are effective for the control of CO, NMHCs, VOCs, and formaldehyde and other [hazardous air pollutants (HAPs)] from diesel and lean-burn gas engines. Oxidation catalysts consist of a substrate made up of thousands of small channels. Each channel is coated with a highly porous layer containing precious metal catalysts, such as platinum or palladium. As exhaust gas travels down the channel, hydrocarbons and carbon monoxide react with oxygen within the porous catalyst layer to form carbon dioxide and water vapor. The resulting gases then exit the channels and flow through the rest of the exhaust system.
>
> An oxidation catalyst has two simultaneous reactions:
>
> Oxidation of carbon monoxide to carbon dioxide:
>
> $$2CO + O_2 \rightarrow 2CO_2$$
>
> Oxidation of hydrocarbons (unburnt and partially burnt fuel) to carbon dioxide and water:
>
> $$C_xH_{2x+2} + [(3x+1)/2]O_2 \rightarrow xCO_2 + (x+1)H_2O$$

This 2015 report states that oxidation catalysts can reduce VOC emissions by 60–99%, as well as reduce CO emissions by 70–99%, non-methane HC by 40–90%, and formaldehyde and other hazardous air pollutants by 60–99%.[229] If a lean-burn engine is equipped with SCR for NOx control, an oxidation catalyst can be added to the SCR design.[230]

Cost information of oxidation catalyst was provided to EPA in 2010 to help determine national impacts associated with EPA's RICE NESHAP.[231] The analysis, performed by E^C/R Incorporated, was based on 2009 cost data for oxidation catalyst from industry groups, vendors, and manufacturers of RICE control

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[228] *See* Manufacturers of Emission Controls Association, Emission Control Technology for Stationary Internal Combustion Engines, Revised May 2015, at page 8, Section 1.2.1, *available at*: http://www.meca.org/resources/MECA_stationary_IC_engine_report_0515_final.pdf.
[229] *Id.*
[230] *Id.* at 7.
[231] Memo from EC/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010).

technology. E^C/R Incorporated performed a linear regression analysis[232] on the oxidation catalyst cost data set for 2-stroke lean-burn engines and for 4-stroke lean-burn engines to establish an equation for each type of engine to estimate total annual cost and total capital costs as follows:

2SLB Oxidation Catalyst Total Annual Cost = $11.4 x HP + $13,928

2SLB Oxidation Catalyst Total Capital Cost = $47.1 x HP + $41,603

4SLB Oxidation Catalyst Total Annual Cost = $1.81 x HP + $3,442

4SLB Oxidation Catalyst Total Capital Cost = $1.81 x HP + $3,442

Where HP equals the engine size in horsepower.

E^C/R Incorporated developed equations to reflect total annual costs oxidation catalyst assuming a 7% interest rate and a 10-year life for amortizing the capital costs of control and adding in the annual operation and maintenance costs.[233] For the same reasons discussed regarding NSCR in Section II.C. above, it is reasonable to assume a 15-year life of oxidation catalyst controls at lean-burn RICE. Further, a lower interest rate of 5.5% is the appropriate interest rate to currently apply pursuant to the recommendations of EPA's Control Cost Manual for determining annualized capital costs of oxidation catalyst. Table 17 below provides the capital costs for oxidation catalysts at various size gas-fired lean-burn RICE and the total annualized cost of the control, assuming a 5.5% interest rate and a 15-year life.

Table 17. Capital and Annual Costs of Oxidation Catalyst at Lean-Burn RICE.[234]

ENGINE TYPE	HORSEPOWER	TOTAL CAPITAL COSTS	TOTAL ANNUALIZED COSTS
2SLB	50	$43,958	$12,619
	75	$45,136	$12,853
	100	$46,313	$13,088
	250	$53,378	$14,496
	500	$65,153	$16,843
	1000	$88,703	$21,536
	1500	$112,253	$26,229
4SLB	50	$3,533	$3,381
	75	$3,578	$3,425
	100	$3,623	$3,468
	250	$3,895	$3,727
	500	$4,347	$4,160
	1000	$5,252	$5,025
	1500	$6,157	$5,890

[232] *Id.* at 5-6.
[233] *Id.* at 5-6 and Appendix A.
[234] Cost calculations based on E^c/R equations from above, but assuming a 15-year life and a 5.5% interest rate.

A 2019 report by SCAQMD indicates that 500 stationary lean-burn engines have been fitted with oxidation catalyst.[235] In Colorado, sixty lean-burn RICE of sizes greater than 500 hp were required to install oxidation catalyst under the 2004 Denver Early Action Compact rulemaking.[236] As of July 1, 2010, Colorado requires all existing lean-burn RICE greater than 500 hp in the state's ozone action areas to install and operate an oxidation catalyst with an emission performance standard of 0.7 g/hp-hr.[237] Colorado only exempted lean-burn engines in the Denver area from the requirement to install oxidation catalyst if the cost was greater than $5,000/ton.[238] There are also several examples of oxidation catalyst being required as BACT for VOCs for lean-burn RICE. For example, in Missouri, BACT for lean-burn RICE at the Mid-Kansas Electric Company, LLC's Rubart Station was based on good combustion practices and an oxidation catalyst with a VOC BACT limit equivalent to 0.2 g/hp-hr for loads of 50% or higher.[239] In another example, BACT for RICE at the Irving Generating Station in Arizona was based on use of an oxidation catalyst with a VOC BACT limit (less formaldehyde) of 0.7 g/hp-hr.[240] In the BACT analysis for the Irving Generating Station several other recent examples were presented demonstrating consistent VOC BACT limits for natural gas-fired RICE, including limits as low as 0.3 g/hp-hr.[241]

In summary, oxidation catalyst is an available control technology that should be considered as a reasonable progress control option to reduce VOC emissions for lean-burn gas-fired RICE.

VOC Controls for Rich-Burn RICE

As discussed in Section II.C. above, NSCR is a three-way catalyst applicable to rich-burn RICE units, which not only removes NOx emissions, but also reduces CO and VOC emissions. In addition to the NSCR catalyst and housing, NSCR requires installation of an oxygen sensor and an AFRC ensure optimum air-to-fuel ratios to ensure conditions are NSCR is the primary VOC control that is implemented for rich-burn gas-fired RICE. Colorado has indicated that an "oxidation catalyst using additional air can be installed downstream of the NSCR catalyst for additional CO and VOC control."[242] The costs for NSCR have been detailed above in Section II.C. NSCR's cost effectiveness for NOx control and its widespread required use, as shown in the state and local air agency rules detailed in Table 15 above, indicates that NSCR must be considered as a reasonable progress control option to reduce VOC emissions from rich-burn RICE.

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[235] SCAQMD, Draft Staff Report, Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines, September 2019, at D-1, *available at*: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1110.2/rule-1110-2-draft-staff-report---final.pdf?sfvrsn=6.

[236] *See* CDPHE RP for RICE at 3. *See also* Colorado Regulation No. 7, Part E, Section I.B., *available at*: https://drive.google.com/file/d/16qTQLSTX1T49DYWp3voXRNl4_g-vbhQT/view.

[237] Colorado Regulation 7 (5 CCR 1001-9) Part E 1. Control of Emissions from Engines.

[238] *Id.* at Section I.C.4. of Part E.

[239] Prevention of Significant Deterioration Air Construction Permit Application for Mid-Kansas Electric Company, LLC Rubart Station (July 2012), *available at:* http://www.kdheks.gov/bar/midkanec/Mid-Kansas_Rubart_Station_PSD_Air_Permit_App_12_19_12.pdf.

[240] Application for a Prevention of Significant Deterioration (PSD) Authorization and Significant Revision to Class I Air Quality Permit for Irving Generating Station, Tucson Electric Power (2017), *available at*: https://webcms.pima.gov/UserFiles/Servers/Server_6/File/Government/Environmental%20Quality/Air/TEP%20PSD%20Webpage/17-12-19-Sundt-RICE-Project-Revised-Application.pdf.

[241] *Id.* Table 5-3 at 5-10. Showing sources from Texas, Oregon, Kansas, and Hawaii receiving permits between 2013 and 2016.

[242] CDPHE RP for RICE at 6.

IV. CONTROL OF NOx EMISSIONS FROM NATURAL GAS-FIRED COMBUSTION TURBINES

Natural gas-fired combustion turbines are used in the oil and gas development industry generally for two purposes: (1) power generation and (2) compression. Combustion turbines are sometimes used to provide on-site power to gas processing facilities, or combustion turbines are used to drive compressors. There are several points in the oil and gas production process where compression of the natural gas is required to move the gas in the pipeline. When a combustion turbine is used for gas compression, the turbine drives the compressor, which is typically a centrifugal compressor. [243]

Gas turbines have been used for power generation since the late 1930s and are available in sizes as low as 500 kilowatts (kW) to over 300 Megawatts (MW).[244] Gas turbines produce a high-heat exhaust that can be recovered in a combined heat and power to produce steam to power a generator. This process is referred to as combined cycle power generation. However, in the oil and gas production industry, gas turbines are generally operated in simple cycle mode. Gas turbines can be used in remote locations such as oil and gas wellfields to provide distributed generation and portable power generation.[245] In some cases, combustion turbines are used at power plants developed for the purpose of providing power to oil and/or gas development but which are also selling electricity to the grid. If a power generating source is constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale, then it is considered an electric utility.[246] Although this specific analysis of controls will focus on the gas turbines used for gas compression or used for on-site power (i.e., "distributed generation") at oil and/or gas production and processing facilities, the available air pollution controls are the same for simple cycle turbines regardless of whether or not such turbines are part of an electric utility.

When combustion turbines are used to drive a compressor, there is no electrical generator (although there could be some heat recovery which could be used to generate electricity through a steam turbine).[247] Instead, the turbine shaft power is used as mechanical power to drive a compressor. Regardless of the purpose of the gas-fired combustion turbines, the air pollution controls for the associated visibility-impairing pollutants are the same.

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[243] *See*, *e.g.*, 76 Fed. Reg. 52,738 at 52,761 (Aug. 23, 2011); *see also* Innovative Environmental Solutions, Inc. & Optimized Technical Solutions, Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry, July 2014, at 26, note 1, *available at*: https://www.ingaa.org/File.aspx?id=22780.

[244] EPA Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-1, *available at*: https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies_section_3._technology_characterization_-_combustion_turbines.pdf.

[245] *Id.* at 3-2.

[246] 40 C.F.R. § 60.331(q).

[247] EPA Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at S-2, 3-6, and A-2.

The 2012 Ozone Transport Commission Report refers to a report on costs of NOx controls at gas turbines prepared for the U.S. Department of Energy (DOE) in 1999.[248] That DOE Report, "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines" dated November 5, 1999 (hereinafter "1999 DOE Report")[249] is cited in several EPA and state documents on the cost of NOx controls at gas turbines, including in a Northeast States for Coordinated Air Use Management (NESCAUM) 2000 Status Report on NOx Controls for gas turbines and other sources,[250] which, in turn, serves as EPA's primary reference for the cost of SCR in its recently revised SCR chapter in its Control Cost Manual.[251] The NESCAUM 2000 Status Report on NOx controls also has other cost information for NOx controls for gas turbines. While these reports are twenty years old, the cost analyses have been relied on extensively by EPA and states.[252] In addition, more recent analyses of the costs of NOx controls for gas turbines have been summarized as supporting information for state and local air agency adoption of NOx emission limitations for gas turbines, but those cost analyses are generally not as detailed as the 1999 DOE report. In the discussion below of the NOx pollution control options for gas turbines, we provide information on all of these various cost analyses.

Note that in the following discussion, NOx emission rates are often referred to as parts per million or "ppm." It should be assumed that such concentration rates are in parts per million by volume or "ppmv" measured on a dry basis and corrected to 15% oxygen unless stated otherwise.

A. WATER OR STEAM (DILUENT) INJECTION

Water or steam injection has been used for decades to reduce NOx emissions from gas turbines. EPA describes the control in its "AP-42" emission factor documentation for gas turbines as follows:

> Water or steam injection is a technology that has been demonstrated to effectively suppress NOx emissions from gas turbines. The effect of steam and water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.
>
> Depending on the initial NOx levels, such rates of injection may reduce NOx by 60 percent or higher. Water or steam injection is usually accompanied by an efficiency penalty (typically 2 to 3 percent) but an increase in power output (typically 5 to 6 percent). The increased power output results from the increased mass flow required

[248] *See* 2012 OTC Report at 66-67.
[249] Bill Major, ONSITE SYCOM Energy Corporation, and Bill Powers, Powers Engineering, Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines, prepared for U.S. Department of Energy, November 5, 1999, Appendix A at A-5 (Table A-4), *available at*: https://www.energy.gov/sites/prod/files/2013/11/f4/gas_turbines_nox_cost_analysis.pdf.
[250] NESCAUM, December 2000, Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, Technologies & Cost Effectiveness, at III-21 through III-24 and at III-40 [hereinafter "NESCAUM 2000 Status Report"], *available at*: http://www.nescaum.org/documents/nox-2000.pdf/view.
[251] *See* EPA, Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf 12 and 98 (reference 19).
[252] EPA relied on the cost analyses in the 1999 DOE Report for the Cross-State Air Pollution Rule. *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-10 through 3-18.

> to maintain turbine inlet temperature at manufacturer's specifications. Both CO and VOC emissions are increased by water injection, with the level of CO and VOC increases dependent on the amount of water injection.[253]

The 1999 DOE Report on NOx pollution controls for gas turbines indicates that water or steam injection can achieve a NOx rate of 42 ppm.[254] In a more recent document, EPA states that water or steam injection enables a gas turbine to achieve NOx levels of 25 ppm at 15% oxygen.[255] General Electric also indicates that water injection can reduce NOx emissions to 25 ppm for gas-fired turbines.[256] The achievable NOx rate with water or steam injection likely depends on the uncontrolled NOx rate before water or steam injection, which can vary by turbine size and manufacturer.

Water injection has been a commonly applied retrofit NOx control technology for gas turbines for several decades. Water injection is available to most turbines; however, with advances in dry low NOx combustion techniques (discussed in the next section), it is not necessarily the first NOx control of choice given the lower cost and more effective options being available, depending on the turbine type. The turbine modifications necessary to accommodate water or steam injection could range from replacement of fuel nozzles with nozzles capable of supplying both fuel and water or steam, to replacement of the combustors with combustors designed to operate with water or steam injection, depending on the make and model of the combustion turbine.[257] There would also be other required equipment such as appropriate combustion turbine controls, an onsite water plant to demineralize water with storage or a storage tank for delivered demineralized water, a water injection pump, and a water or steam flow metering station.[258]

The 1999 DOE Report listed the capital and annual operating costs for water injection installed at specific makes/models of combustion turbines, which are reiterated in the table below.

Table 18. Capital and Operating Costs of Water or Steam Injection for Select Combustion Turbines[259]

Turbine Make/Model	Size, MW	Size, hp	Capital Costs of Water/Steam Injection 1999$	Annual Costs (Excluding Capital Recovery), 1999$
Solar Centaur 50	4.2 MW	5,632 hp	$405,500	$79,000
Allison 501-KB5	4.0 MW	5,364 hp	$291,000	$100,000
GE LM2500	22.7 MW	30,441 hp	$1,083,175	$294,000
GE MS7001F	161 MW	215,904 hp	$4,834,770	$1,325,000

[253] EPA, Compilation of Air Pollutant Emission Factors (AP-42), Section 3.1 Gas Turbines, April 2000, at 3.1-6.
[254] 1999 DOE Report, Appendix A at A-5 (Table A-4).
[255] EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.
[256] *See* GE Power, Water Injection for NOx Reduction, at https://www.ge.com/power/services/gas-turbines/upgrades/water-injection-for-nox-reduction.
[257] 2012 OTC Report at 62.
[258] *Id.*
[259] *See* 1999 DOE Report, Appendix A at A-5 (Table A-4).

The 1999 DOE report determined the annualized costs of control assuming only a 15-year life of controls and a 10% interest rate.[260] The DOE report provides no discussion as to why it assumed a 15-year life of controls, other than to state that EPA used the same 15-year life in a 1993 NOx control document.[261] There is no documented justification for assuming a 15-year life of water or steam injection controls for a combustion turbine. Instead, it is reasonable to assume that the design life of a combustion control like water or steam injection at a gas-fired combustion turbine is equal to the design life of the combustion turbine. A literature review indicates that 25 to 30 years is the design life of a gas combustion turbine.[262] Indeed, a review of permitted compressor stations and gas processing facilities in the state of New Mexico shows several combustion turbines operating today that were installed more than 30 years ago.[263] For the purpose of determining the annualized cost of controls, an assumption of a 25-year life of a water or steam injection system is more than reasonable and justified. Thus, to determine annualized costs based on the capital and operational expenses for water/steam injection presented in Table 18 above, a 25-year life of controls was assumed. Further, to be consistent with EPA's Control Cost Manual, which recommends the use of the bank prime interest rate,[264] a lower interest rate of 5.5% was assumed.[265] In its 2019 cost calculation spreadsheet for SCR provided with its Control Cost Manual, EPA used an interest rate of 5.5%.[266] The annualized costs of controls are presented for the four turbine types in Table 19 below.

The 1999 DOE Report calculated cost effectiveness of water or steam injection for the four turbine models listed in Table 18 above based on achieving a NOx rate of 42 ppm.[267] EPA relied on these cost estimates in its 2016 Technical Support Document for the Cross-State Air Pollution Rule regarding non-EGU NOx emissions controls, stating that the "generally accepted threshold" NOx emission rates that can be achieved with water injection was 42 ppmvd.[268] In its 2016 TSD for the CSAPR rule, EPA did not escalate the costs of controls from 1999 dollars.[269] As discussed above, lower NOx rates with water or steam injection of 25 ppm are generally achievable. Thus, in Table 19 below, the cost effectiveness of

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[260] *Id.* at 3-1. *See also* EPA's January 1993 Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines (EPA-453/R-93-007) at 6-222 [hereinafter referred to as "1993 ACT for Stationary Gas Turbines"].

[261] In the 1993 NOx control document, EPA also assumed a 15-year life for SCR, when now EPA assumes a 20 to 30-year life of SCR systems, depending on the application. *See,* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction at pdf page 80.

[262] *See*, *e.g.*, Sargent & Lundy Combined-Cycle Plant Life Assessments, *available at*: https://sargentlundy.com/wp-content/uploads/2017/05/Combined-Cycle-PowerPlant-LifeAssessment.pdf; GE Power Generation, GE Gas Turbine Design Philosophy, *available at*: https://www.ge.com/content/dam/gepower-pgdp/global/en_US/documents/technical/ger/ger-3434d-ge-gas-turbine-design-philosophy.pdf; NREL, Annual Technology Baseline, Natural Gas Plants, *available at*: https://atb.nrel.gov/electricity/2018/index.html?t=cg; Solar Turbines, Industrial Power Generation, Taurus 70, Benefits and Features, *available at*: https://www.solarturbines.com/en_US/products/power-generation-packages/taurus-70.html.

[263] *See* Title V air operating permits for Chaco Gas Plant, Pecos River Compressor, and Kutz Canyon Gas Plant, among others, available on the New Mexico Environment Department's website.

[264] US EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.

[265] *See e.g.*, https://fred.stlouisfed.org/series/DPRIME.

[266] *Available at* https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

[267] *Id.* at A-3

[268] 2016 EPA CSAPR TSD for Non-EGU Emissions Controls, November 2015, Appendix A at 3-10 through 3-12.

[269] *Id.*

water/steam injection is calculated both to comply with a 42 ppm limit and a 25 ppm limit, based on a 25-year life and a 5.5% interest rate.

Table 19. Cost Effectiveness to Reduce NOx Emissions by Water or Steam Injection for Select Combustion Turbines Operating at 91% Capacity Factor[270]

Turbine Make/Model	Size, MW	Size, hp	Annualized Costs of Water/Steam Injection 1999$	Cost Effectiveness of Water/Steam Injection to Meet 42 ppm NOx Rate (1999$)	Cost Effectiveness of Water/Steam Injection to Meet 25 ppm NOx Rate (1999$)
Solar Centaur 50	4.2	5,632	$109,230	$1,496/ton	$1,265/ton
Allison 501-KB5	4.0	5,364	$121,694	$1,323/ton	$1,153/ton
GE LM2500	22.7	30,441	$374,750	$846/ton	$752/ton
GE MS7001F	161	215,904	$1,685,429	$409/ton	$373/ton

In sum, the cost effectiveness of water or steam injection at a gas-fired turbine is in the range of $1,150-$1,500/ton for the smaller turbines, $750 to $850/ton for a mid-sized turbine, and $375 to $410 for a large turbine. It must be noted that this cost effectiveness analysis is based on an assumed 8,000 hours of operation per year.[271] A 2012 document of technical information on the oil and gas sector available on the Ozone Transport Commission's website indicates that "on average a compressor unit will tend to experience an annual average capacity factor of approximately 40%."[272] This is presumably an average across all compressor engines used in the oil and gas sector, and there are very likely some compressors that do operate at 90% capacity factors. Indeed, the Ozone Transport Commission document indicates that "[f]or many mainline natural gas compressor stations, industry data indicated that the gas compressor stations have compressors in operation 24 hrs/day and 365 days/year, although not all compressors may be operating or may not be operating at high capacity."[273] Given that a compressor station typically is composed of multiple compressors either in parallel or in series powered either by combustion turbines or by reciprocating engines, it seems very likely that one or more of the compressors at a compressor station would operate at a high capacity factor while others would be operated at lower capacity factors, depending on the volume of gas that is being moved through the pipeline at the time. To provide a complete analysis of the range of costs of water or steam injection at a gas-fired combustion turbine, the cost effectiveness analysis of the 1999 DOE Report was revised to reflect a 40% capacity factor. Specifically, the fuel penalty cost (due to the reduction in turbine efficiency with water injection) and all costs dependent on the gallons of water used per year (i.e., the

[270] *See* 1999 DOE Report, Appendix A at A-5 (Table A-4). Capital costs in 1999 dollars were updated from 1999 to 2018 dollars based on CEPCI and CPI indices. Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines and a 91% operating capacity factor was assumed, reflective of the assumed 8,000 hours of operation per year in the November 1999 DOE Cost Analysis report.
[271] *Id.*, Appendix A at A-5.
[272] 2012 OTC Report at 16.
[273] *Id.*

water costs, water treatment costs, associated labor costs, and water disposal costs) in the annual costs of the 1999 DOE Report were reduced by 56% to reflect the reduction in operating hours when the units operate at a 40% capacity factor compared to a 91% operating factor.[274] Also, the tons of NOx reduced per year were revised to reflect operations at a 40% capacity factor.

Table 20. Cost Effectiveness to Reduce NOx Emissions by Water or Steam Injection for Select Combustion Turbines Operating at 40% Annual Capacity Factor[275]

Turbine Make/Model	Size, MW	Size, hp	Annualized Costs of Water/Steam Injection 1999$	Cost Effectiveness of Water/Steam Injection to Meet 42 ppm NOx Rate (1999$)	Cost Effectiveness of Water/Steam Injection to Meet 25 ppm NOx Rate (1999$)
Solar Centaur 50	4.2	5,632	$85,649	$2,675/ton	$2,257/ton
Allison 501-KB5	4.0	5,364	$90,021	$2,232/ton	$1,940/ton
GE LM2500	22.7	30,441	$255,506	$1,316/ton	$1,166/ton
GE MS7001F	161	215,904	$1,060,507	$587/ton	$533/ton

EPA's 2016 TSD for the CSAPR rule provided algorithms for estimating the total capital investment and the total annual costs of water injection based on the hourly heat input of the combustion turbine. These equations were based on a 1993 EPA Control Technique guideline as well as the 1999 DOE Report, and the total annual cost algorithms assumed a 15-year equipment life and a lower interest rate of 7%, but still high compared to today's interest rates.[276] The cost algorithms of EPA's 2016 TSD for the CSAPR Rule are reprinted below.[277]

<u>Water Injection/Gas Turbines:</u>

Total Capital Investment (1999 dollars) = 27665 x (MMBtu/hr)^0.69

Total Annual Costs (1999 dollars) = 3700.2 x (MMBtu/hr)^0.95

<u>Steam Injection/Gas Turbines:</u>

Total Capital Investment (1999 dollars) = 43092 x (MMBtu/hr)^0.82

Total Annual Costs (1999 dollars) = 7282 x (MMBtu/hr)^0.76

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[274] It is possible that other items in the annual costs should also be reduced to reflect a 40% capacity factor, but it was not clear how to adjust those other costs.

[275] *See* 1999 DOE Report, Appendix A at A-5 (Table A-4). Capital costs in 1999 dollars were updated from 1999 to 2018 dollars based on CEPCI and CPI indices. Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines and a 40% operating capacity factor was assumed. The annual costs due to the fuel penalty, water use, water treatment, associated labor, and water disposal were decreased by 56% to reflect a 40% operating capacity factor as opposed to a 91% capacity factor.

[276] *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-11 to 12 and Appendix B at B-2.

[277] *Id.,* Appendix A at 3-12.

While the cost estimates and cost algorithms are of a cost basis that is from 1999, it is important to note that beginning in the mid- to late-1990s, EPA and several state and local air agencies have found that the costs of control to achieve NOx emission limits of 42 ppmv or even lower were cost effective to require such a level of control on existing gas turbines. This will be discussed further in Section IV.D. below. It is not possible to accurately escalate these costs in 1999 dollars to 2019 dollars. The CEPCI has been used extensively by EPA for escalating costs, but EPA states that using the indices to escalate costs over a period longer than five years can lead to inaccuracies in price estimation.[278] Further, the prices of an air pollution control do not always rise at the same level as price inflation rates. Moreover, as an air pollution control is required to be implemented more frequently over time, the costs of the air pollution control often decrease due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc. Thus, the costs for water or steam injection are presented on a 1999 dollar cost basis in this report, but in any event, Table 29 in Section IV.D. of this report shows that numerous state and local air agencies found that water or steam injection was cost effective to require as a retrofit NOx pollution control at numerous gas turbines.

The environmental and energy impacts of the use of water or steam injection include the following:

- Requires the use of water, likely including a water treatment system, and disposal of wastewater
- Energy penalty due to decreased combustion turbine efficiency, but also increased power output
- May increase turbine maintenance requirements, depending on turbine type
- Can increase carbon monoxide and HC/VOC emissions[279]

Water use and water availability may be a significant environmental impact for this control technology, especially for locations in the arid West that already have water shortage issues. The 1999 DOE Report included information on expected water usage of water injection at the four turbines evaluated for the cost effectiveness analysis,[280] which can be projected into annual water use for water injection at these turbine types. The projected annual water use is provided in the table below, for both operating at a 91% capacity factor and at a 40% capacity factor. The amount of water needed for water injection is directly related to the operating capacity factor of the unit, with more water being needed for units operating at higher capacity factors.

Table 21. Projected Water Use of Water/Steam Injection at Gas-Fired Combustion Turbines[281]

Turbine Model	Size, MW	Annual Water Use at 91% Capacity Factor	Annual Water Use at 40% Capacity Factor
Solar Centaur 50	4.2	1,401,407	616,003
Allison 501-KB5	4.0	1,889,269	830,448
GE LM2500	22.7	7,093,130	3,117,859
GE MS7001F	161	95,166,555	41,831,453

[278] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, at 19.
[279] *See*, *e.g.*, EPA's 1993 ACT for Stationary Gas Turbines at 2-41.
[280] *See* 1999 DOE Report, Appendix A at A-5.
[281] *Id.*

As shown by the above table, water use with water/steam injection significantly increases with larger turbines and with units operated at higher capacity factors.

In addition to water availability, according to EPA, "[w]ater purity is essential for wet injection systems in order to prevent erosion and/or the formation of deposits in the hot sections of the gas turbine."[282] Water quality may be more of an issue for remote sites, especially if surface water or well water is used for the water supply.[283] The costs for the water use, treatment, and disposal, as well as the energy penalty costs, were taken into account in the annual costs of controls used in the NOx cost effectiveness analyses presented in Tables 19 and 20 above.[284]

Notwithstanding the high water usage, water or steam injection is a well-proven and cost effective control for NOx emissions from gas combustion turbines of all sizes. As is discussed in Section IV.D. below, NOx limits reflective of water or steam injection have been required by EPA and numerous state and local air agencies, and water or steam injection is used to control NOx at combustion turbines extensively throughout the U.S. However, for turbines constructed in the early 1990s or later,[285] dry low NOx combustion controls were much more commonly used at gas-fired combustion turbines than water or steam injection, due to lower costs of control, improved NOx control, and the fact that there would be no need for use and treatment of water.[286] Dry low NOx combustors are also available for retrofit for several turbine makes and models. This technology to control NOx is discussed in the next section of this report.

B. DRY LOW NOx COMBUSTION

In the late 1980s, dry low NOx burners (DLNBs) became available on larger turbines[287] and, currently, such controls are available on all new turbines. As described by EPA, "[l]ean premixed combustion . . . pre-mixes the gaseous fuel and compressed air so that there are no local zones of high temperatures, or 'hot spots,' where high levels of NOx would form. Lean premixed combustion requires specially designed mixing chambers and mixture inlet zones to avoid flashback of the flame."[288] Many DLNBs can achieve reduced NOx rates across the full load range of a gas turbine.[289] DLNBs are also available to retrofit to several types of combustion turbines. General Electric has dry low NOx burner retrofit

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[282] *Id.* at 7-10.
[283] *Id.*
[284] 1999 DOE Report, Appendix A at A-5 (Table A-4).
[285] Dry low NOx combustors were first developed by GE in the early 1990s. *See* CARB, Report to Legislature, Gas-Fired Power Plant NOx Emission Controls and Related Environmental Impacts, May 2004, at 19, *available at*: https://ww3.arb.ca.gov/research/apr/reports/l2069.pdf.
[286] *Id.* at 2-8.
[287] As discussed in Chapter 7, Controlling NOx Formation in Gas Turbines, by Brian W Doyle, September 2009, at 7-1, which is part of Chapter 10 of the EPA's Air Pollution Training Institute Class APTI 418, *available at*: https://www.apti-learn.net/lms/register/display_document.aspx?dID=39.
[288] EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.
[289] As discussed in 2012 OTC Report at 62.

options for many of its turbine makes and models, and Solar Turbines has an extensive line of retrofit kits including Solar Turbines' SoLoNOx™ technology.[290] To retrofit such DLNBs, the turbines' combustors must be replaced and there may be changes necessary to associated piping and turbine combustion controls.[291]

Based on the range of NOx emission rates that have been reported as achievable with DLNBs, these combustion controls can achieve in the range of 80% to 95% control of NOx emissions.[292] For the turbines for which DLNBs are available, NOx rates have generally ranged from 9–15 ppm.[293] The 1999 DOE Report assumed only a 25 ppmv NOx rate would be achieved at most of the combustion turbines with DLN combustion which reflects approximately 84% NOx reduction, although the DOE report also calculated costs for a larger turbine to meet a 9 ppmv NOx rate which reflects approximately 95% NOx reduction.[294] The 1999 DOE Report indicates that the operation and maintenance costs increase with the lower NOx rate being achieved.[295] The ability to achieve 9 ppmv NOx rates with dry low NOx combustors is not limited to large turbines, such as the GE Frame 7FA turbine (169.9 MW) for which the 1999 DOE Report calculated costs to achieve a 9 ppm NOx rate. Solar Turbines makes several turbines that are guaranteed to achieve 9 ppmvd NOx with Solar Turbines' SoLoNOx™ burners, including the Solar Centaur 50L which is rated at 6,276 horsepower (< 5 MW).[296] However, the ability to achieve 9 ppm NOx rates through dry low NOx combustor retrofits to existing turbines is likely more limited. Solar Turbines indicates that SoLoNOx™ retrofits are available for the Solar Taurus 70 gas turbine (11,110 horsepower).[297] GE recently announced NOx upgrades completed at 9 GE 9E Gas Turbines (132 145 MW) at a facility in China with its DLN1.0+ with Ultra Low NOx combustors to achieve about 7.5 ppm NOx rates.[298]

In its 2016 CSAPR TSD for Non-EGU NOx Emissions Controls, EPA relied on the cost analyses for DLNBs presented in the November 1999 DOE Report.[299] However, EPA acknowledged that, except for the costs for a 169 MW unit, the costs reported in the 1999 DOE Report are "incremental [costs] relative to the costs of a conventional combustor."[300] Table 22 below reflects the cost effectiveness calculations presented in the 1999 DOE report, but with changes made to the interest rate to reflect a 5.5% interest rate consistent with the EPA's Control Cost Manual and to change and life of the controls to the expected life of a combustion turbine of twenty-five years, as was done for the water/steam injection cost analyses. DLN combustors should be expected to last the life of a natural gas-fired combustion

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[290] *Id.* at 66.
[291] *Id.*
[292] *See*, e.g., 2015 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-12, which indicates that 84% control can be met with DLNB achieving a NOx emission rate of 25 ppmvd.
[293] *See* 1999 DOE Report at 2-10.
[294] *Id.* at 2-10 and at Appendix A at A-3.
[295] *Id.* at 2-9 to 2-10.
[296] *See*, *e.g.*, Atlantic Coast Pipeline and Dominion Transmission, Inc., Supply Header Project, Resource Report 9, Air and Noise Quality, September 2015, at 9-24.
[297] *See* https://www.solarturbines.com/en_US/services/equipment-optimization/system-upgrades/safety-and-sustainability/solonox-upgrades.html.
[298] *See* https://www.genewsroom.com/press-releases/ge-completes-worlds-first-dln10-ultra-low-nox-combustion-upgrade-nine-ge-9e-gas.
[299] 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-12.
[300] 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-12. *See also* 1999 DOE Report at 3-3 and Appendix A at A-3.

turbine, which is at least twenty-five years as discussed above. Indeed, there are likely several examples of gas turbines with dry low NOx combustor retrofits that have operated for twenty-five years. The Tennessee Gas Pipeline Company's Compressor Station in Lockport, New York has four Solar Centaur Turbines that were retrofitted with dry low NOx combustion systems in 1995[301] (two of which continue to operate today, twenty-five years later, while the other two were replaced between 2012–2019 with turbines rated at a higher horsepower).[302]

Table 22. Summary of Cost Effectiveness for DLN Combustion (1999$) at 91% Capacity Factor[303]

Turbine Make/Model	Size, MW	Size, hp	Annualized Costs of DLN Combustion 1999$	Cost Effectiveness of Dry Low NOx Combustion to meet 25 ppm NOx Rate	Cost Effectiveness of Dry Low NOx Combustion to Meet 9 ppm NOx Rate
Allison 501-KB7	4.9	6,571	$33,491	$259/ton	
Solar Centaur 50	4.0	5,364	$14,164	$164/ton	
Solar Centaur 60	5.2	6,973	$14,164	$128/ton	
GE LM2500	22.7	30,441	$179,639	$360/ton	
GE Frame 7FA	169.9	227,839	$455,472 (25 ppmv) $474,109 (9 ppmv)	$96/ton	$92/ton

In Table 23 below, the cost effectiveness of dry low NOx combustors is calculated to reflect operation at a 40% capacity factor. Operating at a lower capacity factor should not change the operating or capital costs of the dry low NOx combustion system, given that there is no energy penalty requiring additional fuel use.

[301] NESCAUM 2000 Status Report at IV-36.

[302] *See* New York State Department of Environmental Conservation (NYDEC), Permit 9-2920-00008/00015, Mod 3 Effective 12/2/2014, Issued for the Tennessee Gas Pipeline Co Compressor Station 230-C, *available at*: https://www.dec.ny.gov/dardata/boss/afs/permits/929200000800015_r2_3.pdf. *See also* NYDEC Title V Operating Permit 9-2920-00008/00015 issued 10/23/2018 for the Tennessee Gas Pipeline Co Compressor Station 230-C, *available at*: https://www.dec.ny.gov/dardata/boss/afs/permits/929200000800015_r3.pdf.

[303] *See* 1999 DOE Report, Appendix A at A-3. Capital costs in 1999 dollars were updated from 1999 to 2018 dollars based on CEPCI and CPI indices. Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a twenty-five -year life of controls and a 5.5% interest rate). Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines and a 91% operating capacity factor was assumed.

Table 23. Summary of Cost Effectiveness for DLN Combustion (1999$) at 40% Annual Capacity Factor[304]

Turbine Make/Model	Size, MW	Size, hp	Cost Effectiveness of Dry Low NOx Combustion to meet 25 ppm NOx Rate	Cost Effectiveness of Dry Low NOx Combustion to Meet 9 ppm NOx Rate
Allison 501-KB7	4.9	6,571	$590/ton	
Solar Centaur 50	4.0	5,364	$373/ton	
Solar Centaur 60	5.2	6,973	$292/ton	
GE LM2500	22.7	30,441	$820/ton	
GE Frame 7FA	169.9	227,839	$218/ton	$208/ton

EPA's 2016 TSD for the CSAPR rule provided algorithms for estimating the total capital investment and the total annual costs of DLN combustion based on the hourly heat input of the combustion turbine. These equations were based on a 1993 EPA Control Technique guideline as well as the 1999 DOE Report, and the total annual cost algorithms assumed a 15-year equipment life and a lower interest rate of 7%, which is still high compared to today's interest rates.[305] The cost algorithms of EPA's 2016 TSD for the CSAPR Rule for DLN combustion are reprinted below.[306]

Total Capital Investment (1999 dollars) = 2860.6 x (MMBtu/hr) + 25427

Total Annual Costs (1999 dollars) = 584.5 x (MMBtu/hr)^0.96

In its 2000 Status Report, NESCAUM provided information on the capital and operational expenses for two dry low NOx combustor upgrades to a Solar Centaur turbine (4,700 hp) and a Solar Mars turbine (13,000 hp).[307] Given that it appears the cost data in the 1999 DOE Report may not necessarily reflect retrofit costs (in that, with the exception of the costs for the GE Frame 7FA, the costs were identified in the 1999 DOE Report as "incremental" costs relative to the cost of a conventional combustor), the NESCAUM cost information for retrofit DLNC is also presented here. NESCAUM used a shorter useful life of controls than twenty-five years and a higher interest rate than the 5.5% interest rate used by EPA in its cost spreadsheets provided with its 2018 updates to the Control Cost Manual.[308] NESCAUM also assumed that DLNCs could only reduce NOx to 50 ppm, whereas such combustors should be able to reduce NOx to at least 25 ppm. Thus, in Table 24 below, the cost effectiveness of the DLNC retrofit projects discussed in the NESCAUM report are revised to reflect amortized capital costs assuming a 25-year life and a 5.5% interest rate and to reflect reducing NOx to both 50 ppm and to 25 ppm.

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[304] *See* 1999 DOE Report, Appendix A at A-3. Capital costs in 1999 dollars were updated from 1999 to 2018 dollars based on CEPCI and CPI indices. Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a twenty-five -year life of controls and a 5.5% interest rate). Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines and a 40% operating capacity factor was assumed.

[305] *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-11-12, Appendix B at B-2.

[306] *See id.*, Appendix A at 3-13.

[307] *See* NESCAUM 2000 Status Report at III-16.

[308] *Id.*

Table 24. Summary of Cost Effectiveness for Retrofit DLN Combustion at 40% and 91% Annual Capacity Factors Based on Retrofit Costs Provided in 2000 NESCAUM Report[309]

Turbine Make/Model	Size, hp	Capacity Factor	Cost Effectiveness of Retrofit DLN Combustion to meet 50 ppm NOx Rate	Cost Effectiveness of Retrofit DLN Combustion to Meet 25 ppm NOx Rate
Solar Centaur	4,700	91%	$1,217/ton	$940/ton
Solar Centaur	4,700	40%	$2,769/ton	$2,140/ton
Solar Mars	13,000	91%	$359/ton	$296/ton
Solar Mars	13,000	40%	$816/ton	$673/ton

The NESCAUM 2000 Status Report notes that the capital costs reported for these two turbine types were the "total project costs the owners attributed to the project, which may include project management or other charges associated with the project beyond the equipment and installation."[310] Thus, the costs reflected in Table 24 may be higher than what would typically be reported for DLNC controls in a cost effectiveness analysis consistent with EPA's Control Cost Manual, because EPA does not generally allow such owner's costs to be considered in a cost effectiveness analysis.[311]

In terms of non-air environmental or energy impacts with the use of DLNCs, there are relatively few impacts. There is not an energy penalty associated with the operation of the DLNCs, nor is there any waste product that requires proper disposal. However, there can be increased maintenance required with DLNCs, and those additional maintenance costs are often proprietary.[312] In fact, the increased maintenance costs are not reflected in the cost analyses for the Solar Centaur 50 and Solar Centaur 60 turbines in Tables 22 and 23 above, due to the information being considered proprietary.[313] A non-air quality environmental impact is that DLNBs "tend to create harmonics in the combustor that result in significant vibration and acoustic noise."[314]

EPA has indicated that the length of time to install DLNBs is 6–12 months.[315]

As previously discussed, while the cost estimates and cost algorithms for DLN combustion are of a cost basis that is from 1999-2000, it is important to note that, beginning in the late-1990s, EPA and numerous several state and local air agencies have found that the costs of control to achieve NOx emission limits of 25 ppmv or even lower were cost effective to require such a level of control on existing gas turbines. This will be discussed further in Section IV.D. below.

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[309] *Id.* at III-16. Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines and both a 91% and a 40% operating capacity factor were assumed.
[310] *Id.*
[311] *See* EPA Control Cost Manual, Section 1, Chapter 2 at 9.
[312] *Id.* at 2-9 and 3-10.
[313] *Id.*, Appendix A at A-3.
[314] *Id.* at 2-9 and Appendix A at A-3.
[315] *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls at 18.

Given the lower costs compared to water or steam injection, along with lower operational costs and no need to have water nearby, it is clear why DLNC has been preferable to water or steam injection since such dry low NOx combustion systems have been available. However, as stated above, these DLNC systems are not available for retrofit for all gas-fired turbines and thus, for many turbines, water or steam injection would be the available combustion control. As Tables 22 through 24 show, DLNC is more cost effective than water or steam injection and can achieve lower NOx rates. Thus, low NOx combustion is a preferable combustion-related retrofit option for gas turbines, if a low NOx combustion retrofit option is available for the turbine make and model.

C. SELECTIVE CATALYTIC REDUCTION

SCR is a post-combustion NOx reduction control that is commonly applied to gas-fired combustion turbines used for power generation. SCR technology can reduce NOx emissions by 80–90% or more and, when used along with water injection or DLNC, it can achieve NOx emission rates in the range of 1.5 to 5 ppm.[316] The 1999 DOE Report stated that SCR was the "primary post-combustion NOx control method in use" as of 1999.[317]

An SCR system consists of a reagent injection system (typically ammonia or urea) and a catalyst. The ammonia or urea (which converts to ammonia in the flue gas) is injected into the exhaust stream and the flue gas then passes over a catalyst reduced NOx to N_2, H_2O, and CO_2. The catalyst selected depends on the temperature range of the flue gas and the size of the catalyst depends on the level of NOx reduction to be achieved. SCR technology requires a reagent injection system, including a storage tank and reagent injectors and controls to regulate the quantity of reagent, and the SCR catalyst. According to the 1999 DOE Report, the cost of conventional SCR had dropped significantly by 1999 with innovations in catalysts allowing for a significant reduction in catalyst volume with no change in NOx removal performance.[318] Catalysts are also available for SCR to work at a variety of flue gas temperatures, from as low as 300 degrees Fahrenheit to as high as 1,100 degrees Fahrenheit.[319] For simple cycle turbines, which are more commonly used in the oil and gas sector, the reactor chamber with the catalyst is in place directly at the turbine exhaust, which may require the use of high temperature catalyst such as zeolite.[320] Several options for SCR catalyst exist for simple cycle turbines. For example, BASF makes several SCR catalysts that it claims can achieve up to 97% NOx reduction.[321] The NOxCat ETZ catalyst is specifically designed for simple-cycle power generating turbines and other high temperature turbine applications.[322] The NOxCat VNX and ZNX catalysts can achieve up to 99%

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[316] *See*, *e.g.*, EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18; 2012 OTC Report at 63.
[317] 1999 DOE Report at 1-5.
[318] *Id.*
[319] *Id.*
[320] *See* EPA, Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, at pdf page 36.
[321] *See* BASF, SCR Catalysts for Power Generation, *available at*: http://www.basf-qtech.com/p02/USWeb-Internet/catalysts/en/content/microsites/catalysts/prods-inds/stationary-emissions/scr-cat-pow-gen.
[322] *See* BASF, NOxCat ETZ, *available at*: http://www.basf-qtech.com/p02/USWeb-Internet/catalysts/en/content/microsites/catalysts/prods-inds/stationary-emissions/nOx-Cat-_ETZ.

NOx reduction and are most effective at a temperature range of 550 to 800 degrees Fahrenheit.[323] A related catalyst called NOxCat VNX-HT is designed for use in aeroderivative simple-cycle turbines that can achieve 99% NOx removal and can reach optimal performance at 800 to 850 degrees Fahrenheit.[324]

Conventional SCR systems can be used with simple cycle turbines if the gas stream is cooled to the optimal temperatures for conventional SCR catalysts, through air dilution or tempering.[325] Further, aeroderivative turbines typically have somewhat lower exhaust gas temperatures which can work better with conventional SCR systems than frame-type turbines.[326] The optimal temperature of the flue gas to both minimize the amount of catalyst needed and ensure the highest NOx removal (> 90%) is 700 to 750 degrees Fahrenheit for conventional SCR catalysts.[327] Conventional catalysts can achieve 80% or greater NOx removal over a wide temperature range of approximately 625 to 900 degrees Fahrenheit.[328] SCR vendors have experience installing SCR to achieve low NOx emission rates on numerous simple cycle turbines of all types and sizes.[329]

In its Control Cost Manual chapter on SCR, which was updated in 2019, EPA cites capital costs of SCR for simple cycle gas turbines that range from $237/kilowatt for a 2 MW gas turbine down to $50/kilowatt for a larger gas turbine, all in 1999 dollars cost basis.[330] For these cost ranges, EPA cites to the NESCAUM 2000 Status Report.[331] That NESCAUM report in turn relies on the 1999 DOE Report, as well as a 1991 report by the Electric Power Research Institute and some personal communications.[332] The NESCAUM 2000 Status report provides a range of cost effectiveness data based on these reports for the application of high temperature SCR to gas turbines of varying operating capacity factors, sizes, and baseline NOx emission rates. Table 25 below presents that data for turbines with year-round high temperature SCR operation.

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[323] *See* BASF, NOxCat VNX & ZNX for Power Generation, *available at*: http://www.basf-qtech.com/p02/USWeb-Internet/catalysts/en/content/microsites/catalysts/prods-inds/stationary-emissions/nox-cat-VNX-ZNX-pow-gen.
[324] *Id.*
[325] *See, e.g.*, Buzanowki, M. and S. McMenamin, Automated Exhaust Temperature Control for Simple-Cycle Power Plants, 2/11/2011, Power Magazine, *available at*: https://www.powermag.com/automated-exhaust-temperature-control-for-simple-cycle-power-plants/?printmode=1.
[326] Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand Curve Reset, prepared for New York Independent System Operator, Inc., at iv, *available at*: http://files.brattle.com/files/7644_independent_evaluation_of_scr_systems_for_frame-type_combustion_turbines.pdf.
[327] *See* EPA, Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, at pdf pages 20-21.
[328] *Id.* at pdf page 20.
[329] *See*, *e.g.*, McGinty, Bob, Mitsubishi Hitachi Power Systems, Gas Turbine & Industrial SCR Systems, Lessons Learned Firing NG and ULSD in Large Frame Simple Cycle Gas Turbine Hot SCR Systems, *available at*: http://cemteks.com/cemtekswp/wp-content/uploads/2016/12/lessons_learned_firing_ng_and_ulsd_in_large_frame_simple_cycle_gas_turbine_hot_scr_systems.pdf; Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand Curve Reset, prepared for New York Independent System Operator, Inc.
[330] US EPA, Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction (June 2019) at pdf page 12.
[331] *Id.* at pdf page 98 (see Reference 19).
[332] NESCAUM 2000 Status Report at III-21 through III-24 and at III-40 (see referenced 11, 16, 9, 14, and 15).

Table 25. Cost Effectiveness for High Temperature SCR Retrofit on Simple Cycle Gas Turbines.[333]

Turbine Size, MW	Turbine Size, hp	Uncontrolled NOx, ppm	Controlled NOx, ppm	Cost Effectiveness of SCR, $/ton (2000$), at listed capacity factor	Capacity Factor
75	100,590	154	15	$849	45%
75	100,590	154	15	$664	65%
75	100,590	154	15	$566	85%
75	100,590	42	7	$2,980	45%
75	100,590	42	7	$2,247	65%
75	100,590	42	7	$1,859	85%
75	100,590	15	3	$8,441	45%
75	100,590	15	3	$6,303	65%
75	100,590	15	3	$5,171	85%
5	7,000	142	15	$3,395	45%
5	7,000	142	15	$2,523	65%
5	7,000	142	15	$2,061	85%
5	7,000	42	5	$11,335	45%
5	7,000	42	5	$8,341	65%
5	7,000	42	5	$6,756	85%

The different shading in the table reflects different levels of NOx combustion controls of the existing turbine:

- Gray shading reflects the cost effectiveness of SCR applied to gas turbines with no water injection or dry low NOx combustion controls, in which case the SCR was assumed to achieve about 90% NOx reductions.
- Blue shading reflects the cost effectiveness of SCR applied to gas turbines with, presumably, water injection which can achieve 42 ppm or lower NOx emission rates, in which case the SCR was assumed to achieve about 83–88% removal.
- Green shading reflects the cost effectiveness of SCR applied to gas turbines with, presumably, low NOx combustion controls that can achieve 15 ppm NOx, in which case the SCR was assumed to achieve 80% removal.

[333] *Id.* at III-24.

The NESCAUM cost effectiveness numbers in Table 25 above reflect a 15-year equipment life and an interest rate of 7.5%.[334] The NESCAUM cost effectiveness numbers were also primarily based on the 1999 DOE report.[335] However, EPA has indicated that a 25-year life is a more appropriate life of an SCR system at a gas turbine used in an industrial setting like a compressor station.[336] Further, as stated above, EPA currently uses a 5.5% interest rate in its cost effectiveness calculations. Tables 26 and 27 below present the cost effectiveness for conventional and high-temperature SCR added to a gas-fired combustion turbine meeting an uncontrolled rate of 42 ppmv, reflective of water or steam injection, to achieve a controlled NOx rate of 9 ppmv, which reflects a 79% reduction in NOx emissions. These cost effectiveness analyses are based on the costs of the 1999 DOE Report, but with the capital cost amortized to reflect a 25-year equipment life and a 5.5% interest rate.[337] The 1999 DOE cost analyses were based on operating 8,000 hours per year, or a 91% capacity factor. Given information previously cited that, on average, a compressor unit may operate at a 40% annual capacity factor,[338] revisions to the cost data and emissions reduced were made to reflect a 40% capacity factor. Specifically, the electricity costs (due to the parasitic load of the SCR system) and the ammonia costs in the direct annual costs of the 1999 DOE Report were reduced by 56% to reflect the reduction in SCR operating hours when the units operate at a 40% capacity factor compared to a 91% operating factor.[339]

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[334] *Id.* at IV-22.
[335] *Id.* at III-21 through III-24 (see cites to Reference 11, which is the 1999 DOE report).
[336] *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80.
[337] 1999 DOE Report at 3-9 to 3-10, Appendix A at A-6 to A-7.
[338] 2012 OTC Report at 16.
[339] It is possible that other items in the direct annual costs should also be reduced to reflect a 40% capacity factor, but it was not clear how to adjust those other costs.

Table 26. Cost Effectiveness to Reduce NOx Emissions by Conventional SCR for Select Combustion Turbines with Existing Water or Steam Injection, Operating at Either a 91% or 40% Annual Capacity Factor[340]

Turbine Model	Size, MW	Size, hp	Uncontrolled NOx, ppm at 15% O2	Controlled NOx with SCR, ppm at 15% O2	Annualized Costs of SCR, 1999$	Cost Effectiveness of Conventional SCR at Stated Capacity Factor, 1999$	Capacity Factor
Solar Centaur 50	4.2	5,632	42	9	$135,475	$11,794/ton	40%
Solar Centaur 50	4.2	5,632	42	9	$143,368	$5,486/ton	91%
GE LM2500	22.7	30,441	42	9	$295,872	$6,098/ton	40%
GE LM2500	22.7	30,441	42	9	$317,134	$3,049/ton	91%
GE Frame 7FA	161	215,904	42	9	$1,426,883	$3,050/ton	40%
GE Frame 7FA	161	215,904	42	9	$1,317,285	$1,679/ton	91%

[340] 1999 DOE Report, Appendix A at A-6 (Table A-5). Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). To reflect a 40% capacity factor, the annual operating costs due to the fuel penalty and ammonia use were decreased by 56%, to reflect a 40% capacity factor rather than a 91% capacity factor. Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines.

Table 27. Cost Effectiveness to Reduce NOx Emissions by High Temperature SCR for Select Combustion Turbines with Existing Water or Steam Injection, Operating at Either a 91% or 40% Annual Capacity Factor[341]

Turbine Model	Size, MW	Size, hp	Uncontrolled NOx, ppm at 15% O2	Controlled NOx with SCR, ppm at 15% O2	Annualized Costs of SCR, 1999$	Cost Effectiveness of High Temperature SCR at Stated Capacity Factor, 1999$	Capacity Factor
Solar Taurus 60	5.2	6,973	42	9	$179,385	$13,238/ton	40%
Solar Taurus 60	5.2	6,973	42	9	$188,760	$6,123/ton	91%
GE LM2500	22.7	30,441	42	9	$324,122	$6,680/ton	40%
GE LM2500	22.7	30,441	42	9	$364,879	$3,305/ton	91%
GE Frame 7FA	161	215,904	42	9	$1,379,722	$3,695/ton	40%
GE Frame 7FA	161	215,904	42	9	$1,680,250	$1,978/ton	91%

Although the above costs reflect a 1999-2000 dollar cost basis, EPA has indicated that the costs of conventional SCR "have dropped significantly over time – catalyst innovations have been a principal driver, resulting in a 20% in catalyst volume and cost with no change in performance."[342] Moreover, high temperature SCR catalysts are not necessarily required for turbines operated in simple cycle mode, as was assumed in the NESCAUM 2000 report, because air tempering can be used to lower the cost of the exhaust gas stream, as discussed above. Thus, it is likely that costs for SCR at gas-fired turbines are lower than the cost estimates in the 1999 DOE report and the NESCAUM 2000 Status Report. Indeed, in 2015, the SCAQMD in California collected SCR cost information from vendors for 20 non-refinery, non-power plant gas turbines including turbines used in gas compression, and total installed costs ranged

[341] 1999 DOE Report, Appendix A at A-7 (Table A-6). Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). The annual costs due to the fuel penalty and ammonia use were decreased by 56% to reflect a 40% capacity factor, rather than the 91% capacity factor. Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines.

[342] *See* EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.

from $1.5 million to $2.9 million with the annual costs ranging from $63,000 to $727,000.[343] These costs reflected SCR achieving 95% control for those turbines with NOx rates of 40 ppm or higher and achieving 2 ppm for those turbines with NOx rates lower than 40 ppm.[344] The cost basis of these costs is not identified, but presumably the costs are from the 2010-2015 timeframe.[345] In 2019, SCAQMD ultimately determined it was cost effective to require SCR retrofits as BARCT for non-refinery, non-power plant combustion turbines. SCAQMD required gas turbines of capacities 0.3 MW and larger that power compressor stations to install retrofit NOx controls to meet a NOx limit of 3.5 ppmv at 15% oxygen and required other gas turbines, such as those used for power generation, to meet a NOx limit of 2.5 ppmv.[346] These limits are required to be met by 2024.[347] Other California air districts have adopted NOx limits for existing simple cycle gas turbines that reflect installation of SCR with NOx limits ranging from 2.5 to 9 ppm.[348] While several of these air districts limits were based on SCR applied to turbines of 10 MW capacity or greater, the SJVAPCD in California adopted NOx limits in the range of 5 to 9 ppmv for gas turbines in 2007 that were based on the installation of SCR, with the higher limits for turbines with capacities between 0.3 MW and 10 MW.[349]

The use of SCR presents several non-air quality and energy impacts, most of which are accounted for in the annual operating costs. Those impacts include the following:

- Parasitic load of operating an SCR system, which requires additional energy (fuel use and electricity) to maintain the same steam output at the boiler.[350]
- The spent SCR catalyst must be disposed of in an approved landfill if it cannot be recycled or reused, although it is not generally considered hazardous waste.[351] The use of regenerated catalyst can reduce the amount of spent catalyst that needs to be disposed of.[352]

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[343] SCAQMD, Preliminary Draft Staff Report, Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM, July 21, 2015, at 183, *available at*: https://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/pdsr-072115.pdf?sfvrsn=2.

[344] *Id.* at 182.

[345] It is assumed the cost data were collected before 2014. *See* November 26, 2014 report entitled "NOx RECLAIM BARCT INDEPENDENT EVALUATION OF COST ANALYSIS PERFORMED BY SCAQMD STAFF FOR BARCT IN THE NON-REFINERY SECTOR," available on SCAQMD's website at https://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/noxreclaimbarct-nonconf-nonrefinery_112614.pdf?sfvrsn=2.

[346] *See* Rule 1134(d)(4), Table II, *available at*: http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1134.pdf.

[347] *Id.*

[348] These other California air districts that adopted NOx limits for gas-fired combustion turbines in the 2.5 to 9 ppm range include Sacramento AQMD, Bay Area AQMD, San Joaquin AQMD, Ventura County AQMD, and Yolo Solano AQMD. Further, it must be noted that while a 9 ppmv NOx limit can be met with ultra-low NOx combustors at some turbines, SCR may be required at other units to meet such a NOx limit.

[349] *See* September 2007, SJVAPCD, Amendments to Rule 4703 (Stationary Gas Turbines), Initial Study and Negative Declaration, at 5, *available at*: https://www.valleyair.org/notices/Docs/priorto2008/08-08-07/Negative%20Declaration.pdf.

[350] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf pages 15-16, and 48.

[351] *Id.* at pdf 18.

[352] *Id.* at pdf 18-19.

- If anhydrous ammonia is used, there would be an increased need for risk management and implementation and associated costs for receiving and storing the anhydrous ammonia.[353] If urea or aqueous ammonia is used as the reagent, the hazards from use of pressurized anhydrous ammonia do not apply.
- Excess ammonia can pass through the SCR (called "ammonia slip"), which then can react with sulfate or nitrate in the ambient air to form ammonium bisulfate or ammonium nitrate (i.e., fine particulate matter).[354] Typically, permitting authorities limit the amount of ammonia slip that may occur with SCR to limit the formation of ammonium bisulfate or ammonium nitrate.

There are typically not overarching non-air quality or energy concerns with this technology, and SCR technology is widely used at natural gas-fired combustion turbines. Most of the impacts mentioned above are considered as additional costs of using SCR and are taken into account in the SCR cost effectiveness analysis.

In terms of length of time to install SCR at gas-fired combustion turbines, a report prepared for the SCAQMD found that the typical installation time is about twenty-four months after an engineering firm begins the engineering design for the SCR, or a total of about 27–30 months.[355] These costs should all be included in the annual operating costs.

There are numerous examples of natural gas-fired combustion turbines with SCR installed for NOx control. Just in the electric utility industry, there are at least 310 gas-fired combustion turbines operating with SCR.[356] Clearly, SCR has been considered to be a cost effective NOx reduction technology for combustion turbines, including smaller compressor engines and those that power compressor stations, since at least 2007. Further, SCR is often combined with a combustion control like water injection or dry low NOx combustors, which optimizes the NOx emissions reductions and costs of control.

D. NOx EMISSION LIMITS THAT HAVE BEEN REQUIRED FOR EXISTING NATURAL GAS-FIRED COMBUSTION TURBINES

In 2005, EPA proposed a new NSPS for gas turbines, which was eventually promulgated at 40 C.F.R. Part 60, Subpart KKKK in 2006.[357] In promulgating Subpart KKKK, EPA updated the NSPS for gas turbines, which had last been reviewed for EPA's initial promulgation of NSPS for gas turbines in 1979.[358] As a starting point for considering the level of control that EPA considered to be cost effective as a retrofit control for existing gas turbines, it is instructive to review what EPA required in the NSPS Subpart KKKK

[353] Anhydrous ammonia is a gas at standard temperature and pressure, and so it is delivered and stored under pressure. It is also a hazardous material and typically requires special permits and procedures for transportation, handling, and storage. *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 15.
[354] *See* 1999 DOE Report at 2-11.
[355] *See* ETS, Inc., NOx RECLAIM BARCT INDEPENDENT EVALUATION OF COST ANALYSIS PERFORMED BY SCAQMD STAFF FOR BARCT IN THE NON-REFINERY SECTOR, FINAL REPORT, NOVEMBER 26, 2014, at 17.
[356] Based on a search on EPA's Air Markets Program Database, *available at*: https://ampd.epa.gov/ampd/.
[357] 70 Fed. Reg. 8,314-8,332 (Feb. 18, 2005), 71 Fed. Reg. 38,482-38,506 (July 6, 2006).
[358] 44 Fed. Reg. 52,798.

for existing gas turbines that were modified on or after February 18, 2005. These standards are summarized in the table below. It is important to note that these standards were adopted for gas turbines that generate electricity or that are used for mechanical drive such as at a gas compressor station.

Table 28. NSPS Subpart KKKK NOx Control Requirements for Modifications to Existing Gas Turbines Occurring on or after February 18, 2005.[359]

Turbine Size/Range	Approximate Turbine size range, hp[360]	Subpart KKKK NOx limits for modified sources after 2/2005, ppmv	Control that NOx limit reflects
≤50 MMBtu/hr	≤6,850 hp	150	Probably none
>50 MMBtu/hr and ≤850 MMBtu/hr	>6,850 hp and ≤116,456 hp	42	Water/Steam Injection
>850 MMBtu/hr	>116,456 hp	15	DLNC

Thus, in 2005, EPA found that the cost of water or steam injection or dry low NOx combustion was cost effective for gas-fired turbines with capacity greater than 50 MMBtu/hr (or 116,500 hp, ~86 MW). In considering reasonable progress controls for gas-fired combustion turbines in the oil and gas industry in 2020, the EPA's NSPS NOx limits for sources modified in 2005 or later should be considered the "floor" of potential NOx controls to consider for an existing gas turbine meaning that, at the very minimum, this level of control should be considered cost effective for NOx reductions at gas turbines. However, installation of SCR, with or without water/steam injection or DLNC, would be the much more effective pollution control that should be evaluated in an analysis of controls to achieve reasonable progress, as it has been found to be a cost effective control for gas-fired combustion turbines.

Numerous states and local air agencies have adopted similar or more stringent NOx limits for existing gas turbines to meet, many of which have been in place for 10–20 years. In Table 29 below, we summarize those state and local air pollution requirements. Some of this information was initially obtained from EPA's 2016 CSAPR TSD,[361] which provided a summary of state NOx regulations for gas turbines and other NOx sources as of September 2014.[362] The current state/local requirements for those CSAPR states were confirmed by a review of the state and local rules. The CSAPR TSD focused on the rules applicable in the CSAPR states. EPA found that 9 CSAPR states did not have regulations limiting NOx emissions from existing gas turbines: Alabama, Arkansas, Indiana, Kentucky, Michigan, Mississippi, Oklahoma, South Carolina, and West Virginia.[363] We also reviewed California Air District rules, because several of those air districts have adopted the most stringent NOx emission limitations for existing gas turbines. Indeed, several air districts in California have adopted rules necessitating installation of SCR at

[359] *See* 40 C.F.R. Part 60m Subpart KKKK, Appendix, Table 1.
[360] Converted MMBtu/hr to hp based on following assumptions/conversion factors: Typical heat rate of simple cycle turbine of 9,788 Btu/kWh (per https://www.eia.gov/todayinenergy/detail.php?id=32572), and 0.7457 kW= 1 hp.
[361] *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix B at 11-13.
[362] *Id.*
[363] *Id*. at 13.

virtually all simple cycle turbines. We reviewed some of the remaining states' regulations to determine whether there were NOx limitations for existing gas turbines. Specifically, we reviewed air regulations in New Mexico, Colorado, Utah, Montana, North Dakota, South Dakota, and Washington. It appears there are no NOx emission limits required for existing gas turbines in those states aside from what applies to modified gas turbines under the NSPS Subpart KKKK.

Table 29 is a summary of the NOx emission limits required of existing simple cycle gas-fired combustion turbines in state and local air districts across the United States. It is important to note that these are limits that, unless otherwise noted, currently apply to existing gas turbines. Unlike the NSPS standards of 40 C.F.R. Part 60, Subpart KKKK, gas turbines did not have to be modified to trigger applicability to these emission limits. Instead, these emission limits apply to existing gas turbines and generally require an air pollution control retrofit or an outright replacement of the gas turbine with a new turbine with integrated dry low NOx combustors. These state and local NOx limits were most likely adopted to address nonattainment issues with the ozone NAAQS and possibly also the $PM_{2.5}$ NAAQS. Nonetheless, what becomes clear in this analysis is that numerous states and local governments have adopted NOx regulations that require, at the very least, water or steam injection at existing gas turbines (or DLNC if available) to meet NOx limits of 42 ppmv,[364] and several state/local air agencies have adopted NOx limits in the range of 9–25 ppmv which require dry low NOx combustors or, if unavailable as a retrofit for the turbine type, SCR. Moreover, four California air districts and Georgia have adopted NOx limits for gas turbines that clearly require SCR, probably along with water injection or DLNC, to comply with NOx limits in the range of 2–5 ppmv. The lowest NOx limits are those recently adopted by the SCAQMD which require, by January 1, 2024, gas-fired combustion turbines of 0.3 MW or greater size to meet a 2.5 ppmv limit and compressor gas turbines to meet a 3.5 ppmv limit.

These limits were adopted generally to meet RACT and California BARCT requirements, and costs of controls are considered in making these RACT and BARCT determinations. However, RACT is not necessarily as stringent as BARCT. RACT is generally defined as: "devices, systems, process modifications, or other apparatus or techniques that are reasonably available taking into account: (1) The necessity of imposing such controls in order to attain and maintain a national ambient air quality standard; (2) The social, environmental, and economic impact of such controls."[365] BARCT, on the other hand, is defined as "an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source."[366] BARCT is similar to a BACT determination under the federal PSD program, but it evaluates controls to be retrofit to existing sources, rather than applying to new or modified sources.

[364] Even some of the NOx limits in Table 29 that are higher than 42 ppmv may require water or steam injection to meet the limit.
[365] 40 C.F.R. § 51.100(o).
[366] HSC Code § 40406 (California Code), *available at:* https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=40406.&lawCode=HSC.

Table 29. Summary of State/Local Air Agency NOx Emission Limits for Existing Simple Cycle Gas-fired Combustion Turbines that Require NOx Pollution Controls[367]

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
CA – Sacramento Metro AQMD[368]	Rule 413.301.3	>0.3 MW or 3 MMBtu/hr (RACT)	42
	Rule 413.302.1	<2.9MW or >2.9 MW but <877 hrs/yr (BARCT[369])	42
		>877 hrs/yr & 2.9-10 MW (BARCT)	25
		>877 hrs/yr or >10 MW without SCR (BARCT)	15
		>877 hrs/yr or >10 MW with SCR (BARCT)	9
CA – Bay Area AQMD[370]	Regulation 9-9-301 Effective 1/1/2010:	5-50 MMBtu	42 ppmv or 2.12 lb/MWhr
		>50-150 MMBtu/hr & no retrofit available	42 ppmv or 1.97 lb/MWhr
		>5-150 MMBtu/hr & Water/Steam Injection Enhancement available	35 ppmv or 1.64 lb/MWhr
		>50 150 MMBtu/hr & DLNC available	25 ppmv or 1.17 lb/MWhr
		>150- 250 MMBtu/hr	15 ppmv or 0.70 lb/MWhr
		>250-500 MMBtu/hr	9 ppmv or 0.43 lb/MWhr
		>500 MMBtu/hr	5 ppmv or 0.15 lb/MWhr
		<877 hrs/yr & 50-250 MMBtu/hr	25 ppmv or 1.97 lb/MWhr
		250-500+ MMBtu/yr	25 ppmv or 1.17-0.72 lb/MWhr

[367] This table attempts to summarize the requirements and emission limits of State and Local Air Agency rules, but the authors recommend that readers check each specific rule for the details of how the rule applies to RICE units, and in case of any errors in this table.
[368] http://www.airquality.org/ProgramCoordination/Documents/rule413.pdf.
[369] Best Available Retrofit Control Technology (BARCT) was to be met by May 31, 1997.
[370] http://www.baaqmd.gov/~/media/dotgov/files/rules/reg-9-rule-9-nitrogen-oxides-and-carbon-monoxide-from-stationary-gas-turbines/documents/rg0909.pdf?la=en.

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
CA-SCAQMD[371]	Rule 1134 Effective 12/31/95:	>0.3-2.9 MW	25 (reference limit) x EFF/25%[372]
		2.9-10.0 MW	9 (reference limit) x EFF/25%
		2.9-10.0 MW (no SCR)	15 (reference limit) x EFF/25%
		>10.0 MW	9 (reference limit) x EFF/25%
		>10.0 MW and no SCR	12 (reference limit) x EFF/25%
	By 1/1/24:	>0.3 MW	2.5
		Compressor gas turbine	3.5
CA – SJVAPCD[373]	Rule 4703 Tier 3 limits[374]	>0.3 MW to <3 MW	9
		3-10 MW pipeline gas turbine	8 (steady state) and 12 (non-steady state)
		>3-10 MW & <877 hrs/yr	9
		>10 MW & <200 hr/yr	25
		3-10 MW & >877 hrs/yr and >10 MW and 200-877 hrs/yr	5
		>10 MMW	3-5[375]
	Rule 74.23	0.3-2.9 MW	42

[371] http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1134.pdf.
[372] EFF = gas turbine efficiency, which can never be less than 25%. In other words, this multiplier allows a higher ppm limit than the reference limit if a turbine is more efficient than 25%.
[373] https://www.valleyair.org/rules/currntrules/r4703.pdf.
[374] Note that NOx limits reflective of water/steam injection, DLNC, and/or SCR have been in effect in San Joaquin Valley since 2000. Compliance with the Tier 3 limits was required between 2009-2012.
[375] Tier 2 limits, that were to be complied with in 2005, require turbines greater than 10 MW and greater than 877 hours per year to meet NOx limits in the range of 3-5 ppmv. *See* Table 5-2 of San Joaquin AQMD Rule 4703. Tier 3 limit is 5 ppmv for turbines>10 MW but with operations between 200 hr/yr - 877 hrs/yr. *See* Table 5-3 of San Joaquin AQMD Rule 4703.

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
CA – Ventura County APCD[376]	Currently proposed revisions: By 1/1/24:	2.9-10.0 MW	25 x EFF/25
		>10.0 MW w/SCR	9 x EFF/24
		>10 MW w/o SCR	15 x EFF/25
		>4.0 MW & <877 hrs/yr	42
		All turbines	2.5
CA – San Diego APCD[377]	Rule 69.3.1	≥1.0 & <2.9 MW	42
		≥2.9 & <10.0 MW	25 x EFF/25
		≥10.0 MW w/o installed post combustion air pollution controls	15 x EFF/25
		≥10.0 with installed post-combustion air pollution controls	9 x EFF/25
CA-Yolo Solano AQMD[378]	Rule 2.34	0.3-2.9 MW & >877 hrs/yr AND >4 MW & less than 877 hrs/yr	42
		2.9-10 MW	25
		>10.0 MW	9
CA-Imperial County APCD[379]	Rule 400.1	>1 MW & >400 hr/yr	42
CA-Mojave Desert AQMD[380]	Rule 1159	>4MW & >877 hrs/yr	42
CA – Placer County APCD[381]	Rule 250	>0.3-2.9 MW&>877 hrs/yr	42

[376] http://vcapcd.org/Rulebook/Reg4/RULE%2074.23.pdf.
[377] https://ww3.arb.ca.gov/drdb/sd/curhtml/r69-3-1.pdf.
[378] https://ww3.arb.ca.gov/drdb/ys/curhtml/r2-34.pdf.
[379] https://ww3.arb.ca.gov/drdb/imp/curhtml/r400-1.pdf.
[380] https://ww3.arb.ca.gov/drdb/moj/curhtml/r1159.htm.
[381] https://ww3.arb.ca.gov/drdb/pla/curhtml/r250.pdf.

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
		>4 MW & <877 hrs/yr	42
		2.9-10 MW	25
		>10.0 MW	9
CA – Tehama County APCD	Rule 4: 37	>0.3 MW (exempt if <4 MW&<877 hrs/yr)	42
TX/Houston Galveston Brazoria Ozone NAA[382]	30 TAC 117.310(a)(11)	Emission specs for mass emission cap and trade >10.0 MW	0.032 lb/MMBtu (9 ppmv)
	30 TAC 117.305(c)	Turbines >10.0 MW	42
	30 TAC 117.2010(c)(5)	1.0< &>10.0 MW	0.15 lb/MMBtu
TX/Dallas[383]	30 TAC 117.410(a)(5)	Emission Specs for 8 hr ozone Demo >10.0 MW	0.032 lb/MMBtu (9 ppmv)
	30 TAC 117.405(b)(3)	RACT >10,000 hp	0.15 lb/MMBtu
TX/Beaumont Port Arthur[384]	30 TAC 117.105 (c)	RACT>10.0 MW	42
GA (45 county area – ozone)	Rule 391-3-1-.02.(2)(nnn)1.(i) This appears to be an existing source requirement, with compliance required by 5/1/03	>25 MW, permitted <4/1/00	30
	Rule 391-3-1-.02.(2)(nnn)1.(iii)	>25 MW, permitted after 4/1/00[385]	6
WI (Milwaukee 7 county area)[386]	NR 428.22(1)(g)	>50 MW	25

[382] https://texreg.sos.state.tx.us/public/readtac$ext.ViewTAC?tac_view=5&ti=30&pt=1&ch=117&sch=B&div=3&rl=Y.
[383] https://texreg.sos.state.tx.us/public/readtac$ext.ViewTAC?tac_view=5&ti=30&pt=1&ch=117&sch=B&div=4&rl=Y.
[384] https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=117&rl=105.
[385] This appears to be a new source requirement because compliance was required upon startup.
[386] https://docs.legis.wisconsin.gov/code/admin_code/nr/400/428/IV/22.

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
		25-50 MW	42
NJ[387]	7:27-19.5(d)	>25 MMBtu/hr (case by case exemptions allowed for limits on water supply or no commercially available DLNCs)	2.2 lb/MWhr
	7:27-19.5(g)1 (Table 7)	HEDD Simple Cycle Gas Turbine (Power Generators) >15 MW	1.00 lb/MWhr
DE[388]	Title 7, §1112.3.5 (Table 3-2)	Gas turbines >15 MMBtu/hr	42
IL (Chicago are and Metro East area)[389]	Title 35 Part 217, §217.388a.1.E.	Gas turbines >2.5 MW (4,694 bhp)	42
PA[390]	Ch. 129.97(g)(2)(iv)	Gas turbines > 6,000bhp	42
MD (certain counties)[391]	COMAR 26.11.09.08G(2)	Turbines with Capacity Factor >15%	42
VA (northern VA)[392]	9VAC5-40-7430 (9VAC5-40-7410 requires compliance with RACT)	Turbines >10 MMBtu/hr RACT Limit	42
OH (Cleveland 8 county area)[393]	3745-110-03(E)(1)	>3.5 MW	42
CT[394]	22a-174-22e	Simple Cycle combustion turbines>5 MMBtu/hr	55

[387] https://www.nj.gov/dep/aqm/currentrules/Sub19.pdf.
[388] http://regulations.delaware.gov/AdminCode/title7/1000/1100/1112.shtml#TopOfPage.
[389] http://www.epa.state.il.us/air/rules/rice/217-subpart-q.pdf.
[390] http://www.pacodeandbulletin.gov/Display/pacode?file=/secure/pacode/data/025/chapter129/s129.97.html&searchunitkeywords=129.97&origQuery=129.97&operator=OR&title=null.
[391] http://mdrules.elaws.us/comar/26.11.09.08.
[392] https://law.lis.virginia.gov/admincode/title9/agency5/chapter40/section7430/.
[393] https://www.epa.ohio.gov/portals/27/regs/3745-110/3745-110-03_Final.pdf.
[394] https://www.ct.gov/deep/lib/deep/air/regulations/20160114_draft_sec22e_dec2015(revised).pdf.

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
		Phase I limits (2018-2023) Ozone Season	50
MA[395]	310 CMR 7.19:(7)(a)1	>25 MMBtu/hr	65
NY[396]	6CRR-NY 227-2-4(e)	>10 MMBtu/hr	50
	6CRR-NY 227-3.4(a)(2) New Rule – compliance by 5/1/25[397]	>15 MW	25
LA (Baton Rouge 5 Counties & Region of Influence)[398]	LAC 33.03, Chapter 22, §2201.D.1 (Table D-1A)[399]	≥5-10 MW	0.24 lb/MMBtu (65 ppmv)
		≥10 <MW	0.16 lb/MMBtu (43 ppmv)
MO (St Louis Area)[400]	10 CSR 10-5.510(3)(C)1	>10 MMBtu/hr	75
NC (Charlotte 6 County Area)[401]	15A NCAC 02D.1408	>100 and ≤ 250 MMBtu/hr	75

As the above table shows, eleven state and local air pollution control agencies have adopted NOx emission limits for existing gas-fired simple cycle combustion turbines that reflect operation of SCR or possibly dry low NOx combustors (i.e., NOx emission limits in the range of 2.5 to 9 ppmv). SJVAPCD's NOx limits for pipeline gas compressor stations of 8 ppm (steady state) and 12 ppmv (non-steady state),

[395] https://www.mass.gov/files/documents/2018/01/05/310cmr7.pdf.
[396] https://govt.westlaw.com/nycrr/Document/I4e978e48cd1711dda432a117e6e0f345?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default).
[397] https://www.dec.ny.gov/regulations/116185.html.
[398] https://www.deq.louisiana.gov/resources/category/regulations-lac-title-33.
[399] These are emission factors, used in setting facility emission caps.
[400] https://www.sos.mo.gov/cmsimages/adrules/csr/current/10csr/10c10-5.pdf.
[401] https://files.nc.gov/ncdeq/Air%20Quality/rules/rules/D1408.pdf.

which were adopted in 2007, also reflect application of SCR.[402] The state of Georgia has stringent NOx limits for larger turbines in its 45-county ozone nonattainment area that also likely require SCR to comply with the NOx emission limits. These air agencies have thus found that the levels of NOx control listed in Table 29, including NOx limits as low as the 2.5–5 ppmv range of NOx emissions, are cost effective for existing simple cycle natural gas-fired combustion turbines.

NOx Limits Required for New Gas Turbines Used in the Oil and Gas Sector

Recently, there have been some examples of SCR being required in draft or final air construction permits for proposed new installations of compressor stations powered by gas-fired combustion turbines. Specifically, SCR was proposed to meet BACT requirements for the proposed Buckingham Compressor Station to be located in Virginia, with all four combustion turbines ranging from 6,276 to 15,900 hp to be subject to a NOx BACT emission limit of 3.75 ppmv at 15% oxygen.[403] In addition, SCR was proposed to be installed at the Charles Compressor Station to be located in Maryland,[404] the Northampton Compressor Station to be located in North Carolina,[405] and the Marts Compressor Station to be located in West Virginia.[406] These draft and final permits provide additional evidence of states and companies finding SCR to not be a cost prohibitive control for a compressor station.

E. SUMMARY – NOx CONTROLS FOR EXISTING NATURAL GAS-FIRED COMBUSTION TURBINES

The above analyses and state/local rule data demonstrates that numerous state and local air agencies have found water/steam injection, dry low NOx combustors, and SCR as cost effective controls for natural gas-fired combustion turbines, with costs ranging from $128/ton to $13,500/ton (1999$) to

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[402] *See* September 2007, SJVAPCD, Amendments to Rule 4703 (Stationary Gas Turbines), Initial Study and Negative Declaration, at 5, *available at*: https://www.valleyair.org/notices/Docs/priorto2008/08-08-07/Negative%20Declaration.pdf. The fact that these limits require SCR to meet is reflected in permits for two compressor stations – the Wheeler Ridge Compressor Station and the Kettleman Compressor Station. *See* March 25, 2015 Title V Permit for Southern California Gas Co. Wheeler Ridge Compressor Station, *available at*: https://www.valleyair.org/notices/Docs/2015/03-25-15_(S-1134792)/S-1134792.pdf; February 5, 2018 Title V Permit for Pacific Gas and Electric Company – Kettleman Compressor Station, *available at*: http://www.valleyair.org/notices/Docs/2018/2-5-18_(C-1161601)/C-1161601.pdf.

[403] *See* January 9, 2019 Registration No. 21599, *available at*: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-for-buckingham-county-compressor-station-vacated.

[404] *See* Draft Permit for Dominion Energy Cove Point – Charles Station, *available at*: https://mde.maryland.gov/programs/Permits/AirManagementPermits/Documents/Dominion%20Charles%20Station%20draft%20ptc%20conditions%20for%20compressor%20station2018.pdf. It is not clear whether the final air permit has been issued yet for this facility.

[405] *See* Air Permit No. 10466R00, issued February 27, 2018, *available at*: https://edocs.deq.nc.gov/WaterResources/PDF/bf820b89-33eb-4cf9-bf89-2d6fb31b7418/Final%20Permit%20Northampton%20Compressor%20Station.pdf.

[406] *See* Permit No. R13-3271, issued July 21, 2016, *available at*: https://dep.wv.gov/daq/Documents/July%202016%20Permits%20and%20Evals/041-00076_PERM_13-3271.pdf.

meet NOx limits ranging from 42 ppmv down to 2.5 ppmv. Further, it is notable that, in the rules summarized above in Table 29, the primary exemptions or higher allowable NOx limits for low use turbines are those that operate at 10% or lower annual capacity factors (i.e., less than 877 hours/year), although there are several California districts with no exemptions for low capacity factor turbines. In addition, although there are some states that limited applicability of NOx emission limits to larger turbines (e.g., greater than 10 MW (or greater 13,500 hp or 100 MMBtu/hour)), there are several states and local air pollution control agencies that set NOx limits requiring NOx controls for turbines smaller than 10 MW. In fact, several California districts set a NOx limit reflective of water or steam injection (i.e., 42 ppmv) for turbines as small as 0.3 MW.

As states evaluate the level of NOx control to require at gas-fired combustion turbines associated with the oil and gas industry to make reasonable progress towards the national visibility goal, costs of NOx control should not be a significant consideration in the decision of what NOx emission limits to require existing natural gas-fired combustion turbines to meet, as there are ample examples of existing gas-fired combustion turbines being required to incur similar costs of control. Indeed, SCR should be considered the control technology of choice for NOx removal at gas-fired combustion turbines of 0.3 MW size or larger, including those that operate compressor stations and/or that operate at lower capacity factors. Combustion turbines with SCR should be able to meet NOx limits in the range of 2.5 to 9 ppmv NOx. For those turbines for which SCR is not technically or economically feasible, DLNCs should be the next control technology with NOx emission limits achievable in the 7.5 to 25 ppm range. If DLNCs are not available for retrofit to the turbine model, water or steam injection should be considered for NOx control, which should enable the combustion turbine to meet NOx limits in the range of 25 to 42 ppmv. It also must be recognized that, in some cases, it may be more effective for NOx control — and more cost effective — to require replacement of existing gas-fired turbines with new turbines designed with state-of-the-art dry low NOx combustion controls, as such controls can achieve much lower NOx rates than water or steam injection and do not require water usage.

V. CONTROL OF VOC EMISSIONS FROM NATURAL GAS-FIRED COMBUSTION TURBINES

VOC emissions from natural gas-fired combustion turbines result from incomplete combustion. The same is true for CO emissions. The combustion conditions that favor lower NOx emission rates, such as lower temperature combustion, tend to result in less complete combustion and thus higher VOC as well as CO emission rates.

Similar to RICE units, NOx is emitted at much higher rates from uncontrolled natural gas-fired combustion turbines compared to VOC emissions, with uncontrolled VOC emissions about two orders of magnitude lower than NOx emissions according to EPA's AP-42 emission factor documentation.[407] On the basis of pounds of VOC emission per heat input, EPA's AP-42 emission factors indicate that natural

[407] EPA, AP-42, Section 3.1, Tables 3.1-1 and 3.1-2, *available at*: https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf.

gas-fired combustion turbines emit VOCs at a much lower rate that natural gas-fired RICE.[408] However, it must be noted that EPA's uncontrolled VOC emission factor has an emission factor rating of "D," which means tests are based on a generally unaccepted method and/or from a small number of facilities.[409] Regardless, the same control for VOC emissions from lean-burn RICE units – oxidation catalyst – applies to control of VOC emissions from natural gas-fired combustion turbines.

According to EPA, oxidation catalyst is typically used on combustion turbines to control CO emissions as well as HAP emissions – primarily formaldehyde.[410] Removal of VOCs is a co-benefit of oxidation catalyst at natural gas-fired combustion turbines. Data collected by CARB of emission test results at combustion turbines used for power generation that were equipped with oxidation catalysts, among other air pollution controls, showed VOC emission rates generally in the range of 1 to 3 ppmv at 15% oxygen.[411]

It is not clear that oxidation catalyst has been widely implemented at existing natural gas-fired combustion turbines. According to documentation for EPA's 2019 Risk and Technology Review for its Stationary Combustion Turbine NESHAP, a review of air permits for 719 turbines found 50 units using oxidation catalyst.[412] That said, the data collected by CARB in 2004 indicated 31 natural gas-fired combustion turbines using oxidation catalyst.[413]

In addition, oxidation catalyst has been recently proposed and required for new natural gas-fired combustion turbines used in the oil and gas industry. For example, in its permit application for the Weymouth Compressor Station to be located in Massachusetts, oxidation catalyst was proposed to be installed on a combustion turbine-driven compressor unit to reduce VOCs as well as to reduce CO and HAP to meet BACT. Oxidation catalyst has been proposed to be installed along with SCR at the proposed Buckingham Compressor Station to be located in Virginia,[414] the Charles Compressor Station to be located in Maryland,[415] the Northampton Compressor Station to be located in North Carolina,[416] and the

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[408] Compare VOC emission factors from EPA's AP-42, Section 3.1, Tables 3.1-1 and 3.1-2 to EPA's AP-42, Section 3.2, Tables 3.2-1, 3.2-2, and 3.2-3.
[409] EPA AP-42, Introduction at 8-10.
[410] EPA, AP-42, Section 3.1, at 3.1-7.
[411] *See* CARB, Report to the Legislature, Gas-Fired Power Plant NOx Emission Controls and Related Environmental Impacts, May 2004, Appendix A, *available at*: https://ww3.arb.ca.gov/research/apr/reports/l2069.pdf.
[412] *See* December 11, 2018 Memo from RTI International to Melanie King, EPA, at 3, in EPA's docket for its Risk and Technology Review for the Stationary Gas Turbine NESHAP, Docket ID EPA-HQ-OAR-2017-0688-0066, *available at*: www.regulations.gov.
[413] *See* CARB, Report to the Legislature, Gas-Fired Power Plant NOx Emission Controls and Related Environmental Impacts, May 2004, Appendix A.
[414] *See* January 9, 2019 Registration No. 21599, *available at*: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-for-buckingham-county-compressor-station-vacated.
[415] *See* Draft Permit for Dominion Energy Cove Point – Charles Station, *available at*: https://mde.maryland.gov/programs/Permits/AirManagementPermits/Documents/Dominion%20Charles%20Station%20draft%20ptc%20conditions%20for%20compressor%20station2018.pdf. It is not clear whether the final air permit has been issued yet for this facility.
[416] *See* Air Permit No. 10466R00, issued February 27, 2018, *available at*: https://edocs.deq.nc.gov/WaterResources/PDF/bf820b89-33eb-4cf9-bf89-2d6fb31b7418/Final%20Permit%20Northampton%20Compressor%20Station.pdf.

Marts Compressor Station to be located in West Virginia.[417] These draft and final permits provide evidence of states and companies finding oxidation catalyst to be a cost effective control for a combustion turbine-powered compressor stations.

In summary, oxidation catalyst is an available air pollution control to reduce VOC emissions, as well as to reduce CO and HAP emissions, from natural gas-fired combustion turbines used in the oil and gas industry. States should consider oxidation catalyst when evaluating reasonable progress controls for natural gas-fired combustion turbines used in the oil and gas industry.

VI. CONTROL OF EMISSIONS FROM DIESEL-FIRED RICE

Compression-ignited (*i.e.*, diesel-fired) RICE units are used in oil and gas exploration, production, and transmission sectors. These types of engines are generally used in the oil and gas industry for on-site power generation, as well as to power or to drive drill rigs, drive hydraulic fracturing pumps, and to power other pumping and compression applications. According to EPA's Alternative Control Techniques Document for Stationary Diesel Engines (2010), many of the "stationary" diesel RICE (meaning engines that are not mobile) are designated for continuous power use or used in standby power applications.[418] Company data suggests that those engines used as standby or emergency generators are generally less than 300 horsepower (hp), and diesel engines used for onsite power generation are typically greater than 300 hp although this is not a firm cutoff for standby diesel generator capacities.[419] The size of diesel engines for drilling rigs are likely much larger. A 2014 drilling rig emission inventory prepared for the state of Texas found that the mechanical drill rig engine sizes ranged from 430 hp for vertical wells less than 7,000 feet deep to 1,094 hp for vertical wells greater than 7,000 feet deep.[420] The study also found that, in Texas, mechanical rigs (diesel engines) were used for 96% of shallow vertical wells (< 7,000 feet) and 80% of deep vertical wells (> 7,000 feet), whereas 86% of horizontal wells are drilled by electric rigs.[421] According to the Texas drilling rig report, the trend in new drilling rigs is mostly electric rigs especially for larger drilling rigs, meaning that diesel-fired electrical generating sets are used to power the drilling engines (rather than diesel engines driving the drilling engines).[422] The electrical rigs typically have three large identical diesel generators, with one of the three units designated for standby

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[417] *See* Permit No. R13-3271, issued July 21, 2016, *available at*: https://dep.wv.gov/daq/Documents/July%202016%20Permits%20and%20Evals/041-00076_PERM_13-3271.pdf.

[418] EPA, Alternative Control Techniques Document: Stationary Diesel Engines, March 5, 2010, at 13, *available at*: https://www.epa.gov/sites/production/files/2014-02/documents/3_2010_diesel_eng_alternativecontrol.pdf [hereinafter referred to as "EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE"]. Note, this ACT document expands upon the 1993 and 2000 ACT documents to address pollutants other than NOx.

[419] *Id.*

[420] Eastern Research Group, Inc., 2014 Statewide Drilling Rig Emissions Inventory with Updated Trends Inventories, Final Report, Prepared for Texas Commission on Environmental Quality, July 31, 2015, at 5-4, *available at:* https://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/ei/5821552832FY1505-20150731-erg-drilling_rig_2014_inventory.pdf.

[421] *Id.* at 4-1.

[422] *Id.* at 3-1.

capacity.[423] The Texas inventory report indicates that the typical size of electric generators to power the electric rigs is 1,338 hp.[424] This report was specific to Texas, and other states may have a different mix of size engines used for different types and depth wells. Diesel engine pumps are also used in hydraulic fracturing ("fracking"). In 2016, fracking accounted for 69 percent of all new oil and gas wells, according to the Energy and Information Administration.[425] Diesel engines used to power hydraulic fracturing pumps are generally in the range of 1,000–1,500 hp, with 8 to 12 pumps necessary per well site (total of 20,000+ hp per well site).[426]

A. CONTROL OPTIONS FOR DIESEL-FIRED RICE

Uncontrolled diesel RICE emit several pollutants that can contribute to regional haze, including NOx, particulate matter (PM), SO2, and VOCs. In some cases, the pollutant controls used for one pollutant can negatively or positively affect control of another pollutant. For example, combustion modifications employed to reduce NOx emissions will tend to increase PM emissions and VOC emissions, and vice versa. Controlling SO2, which is achieved by use of ultra-low sulfur diesel (ULSD) fuel, will reduce PM emissions as well. Thus, it can be important to evaluate pollution controls for diesel RICE holistically.

In its 1993 Alternative Control Techniques Document for Stationary RICE, EPA described NOx controls for diesel RICE, including combustion modifications (injection timing retard) and add-on controls (SCR), as follows:

> Ignition timing retard delays initiation of combustion to later in the power cycle, which increases the volume of the combustion chamber and reduces the residence time of the combustion products. This increased volume and reduced residence time offers the potential for reduced NOx formation. … Achievable NOx reductions using IR is engine-specific but generally ranges from 20 to 30 percent. Based on an average uncontrolled NOx emission level for diesel engines of 12.0 g/hp-hr (875 ppmv), the expected range of controlled NOx emissions is from 8.4 to 9.6 g/hp-hr (610 to 700 ppmv). [427]

> Selective catalytic reduction applies to all CI engines and can be retrofit to existing installations except where physical space constraints may exist. … Based on an average uncontrolled NOx emission level of 12.0 g/hp-hr (875 ppmv) for diesel engines, the expected range of controlled NOx emissions is from 1.2 to 2.4 g/hp-hr (90 to 175 ppmv). … Limited emission test data show NOx reduction efficiencies of approximately 88 to 95 percent for existing installations, with ammonia slip levels ranging from 5 to 30 ppmv.[428]

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[423] *Id.*
[424] *Id.* at 5-4.
[425] https://www.eia.gov/todayinenergy/detail.php?id=34732.
[426] *See*, e.g., Solar Turbines, Turbomachinery Considerations in Drilling and Fracturing, Gas Electric Partnership 2013, at 7-8, *available at:* http://www.gaselectricpartnership.com/hReinerKurzTurboMachinery.pdf.
[427] EPA 1993 Alternative Control Techniques Document for RICE at 2-5 and 2-22.
[428] *Id.*

Compression-ignition diesel-fueled engines operate lean, meaning there is excess air during combustion. And while the application of similar control techniques can differ for spark-ignition (gas-fired) and compression-ignition (diesel-fired) engines, according to EPA's 1993 Alternative Control Techniques Document for RICE, the: (1) process; (2) application considerations; (3) performance factors; and (4) potential NOx emissions reductions for SCR applications with diesel engines are similar to those for natural gas applications.[429]

In its 2010 Alternative Control Techniques Document for Stationary Diesel RICE, EPA discusses combining SCR with a particulate filter to reduce both NOx and PM emissions.[430] EPA describes diesel particulate filters (DPF) and catalyzed diesel particulate filters (CDPF) as follows:

> [DPF and CDPF] emission control technologies are designed to remove PM from the diesel engine exhaust stream using a wall flow filter material in which the exhaust gas must pass through a ceramic wall. In addition to PM, the catalyst in the CDPF also reduces emissions of [Total Hydrocarbons (THC)] and CO. … CARB reports PM emission reductions of 85 to 97 percent for various types of verified DPF or CDPFs. The EPA has verified DPF and CDPF systems that achieve up to 90 percent reduction. In addition to the PM reductions, the CDPF filter also reduces emissions of CO and THC by 90 percent but requires sufficient exhaust temperatures to facilitate regeneration by the catalyst. These reductions have been verified by both the CARB and EPA diesel control technology verification programs.[431]

CDPFs are thus a control device for PM and also for VOCs (THC) and CO.

Stationary diesel engine exhaust emissions include SO_2 due to sulfur in fuel, although a smaller percentage of the sulfur in fuel is converted to sulfates (particulate matter). At high temperatures, SO_2 can oxidize to form sulfates, contributing to further increases in PM emissions from engine exhaust. The use of ULSD fuel is essential in conjunction with exhaust treatment control technologies for reducing NOx and PM and is also, by itself, an effective and commonly applied way to reduce SO_2 emissions. Manufacturers require diesel engines equipped with CDPF to use ULSD fuel. EPA, in its 2010 Alternative Control Techniques Document for Stationary Diesel RICE, describes the use of ULSD as follows:

> EPA [] finalized NSPS for stationary CI engines that require all new stationary diesel engines to use ULSD in 2010. This ULSD fuel enables the use of aftertreatment technologies for new and existing diesel engines and can also by itself reduce emissions of criteria pollutants. The use of ULSD reduces the formation of sulfur oxides and particulate sulfates from the diesel engine exhaust. The reductions in PM are expected to be approximately 5 to 30 percent depending on the sulfur content of the fuel that is replaced. … It should be noted that ULSD is prevalent in the fuel pool today, including in some nonroad fuels that may not be labeled as such, and therefore may already be used in many stationary diesel engines.[432]

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[429] EPA 1993 Alternative Control Techniques Document for RICE at 5-73.
[430] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 35.
[431] *Id.* at 32 and 34.
[432] *Id.* at 47 and 48.

In summary, while any one of these pollution controls can be used at a diesel RICE to control one pollutant, the co-benefits of using all of these controls together (ULSD, CDPF, and SCR) ensure the most effective control of NOx, PM, SO2, as well as CO and hazardous air pollutants.

B. EXISTING FEDERAL AIR REGULATIONS FOR DIESEL-FIRED RICE

The diesel engines that power and/or drive drill rigs and wellsite pumping operations may be considered to be nonroad engines (as opposed to stationary engines), if they meet the regulatory criteria to be considered a nonroad engine. According to EPA, a diesel engine is considered a nonroad engine if it is self-propelled or propelled while performing its function or portable or transportable (if it has wheels, skids, carrying handles, a dolly, trailer, or platform), although a nonroad engine becomes a stationary engine if it stays in one location for more than 12 months (or for a full annual operating period of a seasonal source).[433] EPA distinguishes between nonroad diesel engines and stationary diesel engines because the Clean Air Act directs EPA to set emission standards for new nonroad engines and generally does not allow states to set emission standards for nonroad engines except through a specific process outlined in Section 209 of the Clean Air Act.[434]

EPA has established emission limitations to decrease air emissions from nonroad diesel engines using a tiered approach, with the most stringent Tier 4 standards currently in effect for engine manufacturers. See 40 C.F.R. §§89.112, 1039.101, 1039.102. These are emission standards that the manufacturers must meet in their production and sale of diesel engines and for which they demonstrate compliance on a fleetwide basis. There have been four tiers of emission standards applicable to diesel RICE, with Tier 1 standards applying to engines constructed beginning in 1996-1998, Tier 2 standards applying in 2000-2004, Tier 3 standards applying in 2006-2008, and Tier 4 standards applying in approximately 2014 and beyond.[435] The emission standards do not specify any one pollution control technology that needs to be installed to meet the emission limitations. Instead, the standards set limitations on emissions. Generally, the Tier 1, 2, and 3 emission standards were met with advanced engine design, while the Tier 4 emission standards reflect application of CDPF and SCR.[436] These controls reduce PM and NOx emissions by over 90% from diesel RICE. In addition, the Tier 4 standards mandate that ULSD be used in Tier 4 engines.[437] This requirement also ensures reduced SO_2 emissions from diesel engines.

EPA has also established NSPS for stationary diesel engines (i.e., those diesel RICE not considered to be nonroad engines) in 40 C.F.R. Part 60, Subpart IIII. Those emission standards generally require engine manufacturers to meet the same emission standards applicable to nonroad diesel engines for the size and model year, beginning in model year 2007, for non-emergency engines of displacement below 10

[433] *See* EPA's "Understanding the Stationary Engines Rules," at https://www.epa.gov/stationary-engines/understanding-stationary-engines-rules. *See also* 40 C.F.R. §89.2.
[434] Section 209(e)(2) of the Clean Air Act.
[435] *See*, e.g., https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100OA05.pdf.
[436] *See*, e. g., EPA's Frequently Asked Questions from Owners and Operators of Nonroad Engines, Vehicles, and Equipment Certified to EPA Standards, available at https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100U8YP.pdf.
[437] 40 C.F.R. §1037.501(d)(2)

liters per cylinder.[438] Non-emergency engines of displacement higher than 10 liters per cylinder must generally meet the applicable emission standards for marine engines in 40 C.F.R. §94.8 which vary based on year of manufacturer and cylinder displacement.[439] Emergency engines that operate in emergency situations (like standby generators) do not have to meet the Tier 4 standards and instead must meet less stringent standards.[440]

The NSPS have separate requirements for owners or operators of stationary diesel engines that are generally not as stringent either in date of applicability or emission limits as the limits applicable to engine manufacturers. As summarized by an industry website, owners or operators of engines of pre-2007 model year must meet Tier 1 nonroad engine standards for engines less than 10 liters per cylinder and must meet Tier 1 marine standards for engines greater than or equal to 10 but less than 30 liters per cylinder.[441] For engines of 2007 model year or later, owners or operators of engines less than 30 liters per cylinder must buy engines that are certified to meet the NSPS standards applicable to manufacturers.[442] Owners or operators of 2007 model or later year engines greater than or equal to 30 liters per cylinder displacement must meet emission standards that vary depending on the year the engine was installed, with installations after January 1, 2016 having to meet emission limits reflective of application of DPF and SCR.[443]

Significantly, the NSPS do not apply to owners or operators of stationary diesel RICE that have been modified or reconstructed, nor do they apply to engines that were removed from one location and reinstalled at a new location.[444] Further, while the NSPS required by October 1, 2010 the use of ULSD fuel for those engines subject to the NSPS that are below 30 liters per cylinder displacement, engines with greater than or equal to 30 liters displacement that are subject to the NSPS are allowed to use 1,000 ppm sulfur content fuel.[445]

EPA has also adopted a National Emission Standard for Hazardous Air Pollutants for Stationary RICE (RICE NESHAP) that requires emission limits on CO that effectively also limit hazardous air pollutants and VOCs.[446]

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[438] 40 C.F.R. §60.4201. Exceptions existing for engines operated in remote areas of Alaska and in marine offshore installations. 40 C.F.R. §60.4201(f).
[439] See 40 C.F.R. §60.4201.
[440] *See* 40 C.F.R. §60.4202.
[441] *See* https://dieselnet.com/standards/us/stationary_nsps_ci.php. *See also* 40 C.F.R. §60.4204(a).
[442] 40 C.F.R. §60.4204(b).
[443] 40 C.F.R. §60.4204(c).
[444] 40 C.F.R. §60.4208(i).
[445] 40 C.F.R. §60.4207.
[446] 40 C.F.R. Part 63, Subpart ZZZZ.

C. POLLUTION CONTROL UPGRADES OR RETROFITS FOR DIESEL-FIRED RICE

1. REPLACEMENT OF EXISTING DIESEL-FIRED RICE WITH TIER 4 ENGINES

Given that manufacturers are currently producing diesel RICE with integrated SCR and DPF to meet EPA's Tier 4 emission standards, it is likely the more cost effective option to consider the replacement of existing engines with new Tier 4 engines rather than requiring retrofitting of pollution controls. The emission reduction benefits from replacing existing diesel RICE with Tier 4 diesel RICE can be quite significant. It is difficult to directly compare the regulatory emission standards for Tiers 1–3 to the Tier 4 emission standards because the Tier 2 and 3 emission standards for NOx were based on the total of non-methane hydrocarbons (NMHC) plus NOx. EPA's 2010 Alternative Control Techniques Document for Stationary Diesel Engines summarized the NOx and PM emission rates for various size ranges and for the Tiers 1, 2, and 3, based on EPA's Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling – Compression Ignition (EPA 420-P-04-009), April 2004.[447] In the table below, we compare "Tier 0" (pre-1998) and EPA's Tier 1, 2, and 3 emission factors to the emission standards of the Tier 4 standards promulgated by EPA for specific size engines that fall within the various size ranges of applicability for EPA's nonroad emission standards.[448] The table below shows the NOx and PM emission rates expected for each of the four Tiers of diesel RICE rules, as well as NOx and PM emissions from diesel RICE manufactured before the EPA emission standards applied (i.e., pre-1998 or "Tier 0").

[447] *See* EPA's Alternative Control Techniques Guideline Stationary Diesel Engines, March 5, 2010 at 58 and 61 (Tables 5-2 and 5-3).
[448] *See* May 2004, EPA Regulatory Announcement, Clean Air Nonroad Diesel Rule, Table 1, *available at:* https://nepis.epa.gov/Exe/ZyPDF.cgi/P10001RN.PDF?Dockey=P10001RN.PDF.

Table 30. Comparison of NOx and PM Emission Rates for Various Engine Sizes and Tier Engines.[449]

ENGINE SIZE, HP	TIER ENGINE	NOX EMISSIONS, G/HP-HR	PM EMISSIONS, G/HP-HR
75	0	6.89	0.72
	1	5.58	0.47
	2	4.72	0.24
	3	3.00	0.30
	4	3.50[450]	0.02
174	0	8.39	0.40
	1	5.58	0.25
	2	4.00	0.13
	3	2.50	0.15
	4	0.30	0.01
600	0	8.39	0.40
	1	5.58	0.22
	2	4.10	0.13
	3	2.50	0.15
	4	0.30	0.01
750	0	8.39	0.40
	1	5.58	0.22
	2	4.10	0.13
	3	2.60	0.15
	4	2.60	0.075
1500 GEN SET[451]	0	8.9	0.40
	1	5.58	0.22
	2	4.10	0.13
	3	2.50	0.15
	4	0.5	0.02

As shown in the above table, the Tier 4 NOx limits reflect significant NOx reductions from each prior Tier engine for some engine sizes, except the smallest engines and the non-electrical generating set engines that are greater than 750 hp in size for which there is no different between Tier 3 and Tier 4 NOx emissions. The PM emissions, on the other hand, get increasingly more stringent with each Tier engine.

To determine the cost effectiveness of replacing an existing engine with a Tier 4 engine, one needs to know the costs of a Tier 4 engine. A 2010 analysis done by CARB collected cost data from equipment manufacturers for Tier 4 compliant Generator-Set Engines (or "Gen Sets") and determined the average cost per horsepower for a Tier 4 engine equipped with DPF and SCR.[452] Although this CARB analysis was

[449] Data from EPA's Alternative Control Techniques Guideline Stationary Diesel Engines, March 5, 2010 at 58 and 61 (Tables 5-2 and 5-3), and from May 2004, EPA Regulatory Announcement, Clean Air Nonroad Diesel Rule, Table 1.
[450] This limit applies to NMHC plus NOx. *See* https://nepis.epa.gov/Exe/ZyPDF.cgi/P10001RN.PDF?Dockey=P10001RN.PDF.
[451] Generator-set engines or "Gen Sets." These engines are used to operate an electrical generator or an alternator to produce electric power for other applications.
[452] CARB, Analysis of the Technical Feasibility and Costs of After-Treatment Controls on New Emergency Standby Engines at B-11, *available at:* https://ww3.arb.ca.gov/regact/2010/atcm2010/atcmappb.pdf.

for emergency standby engines, the cost data can provide a reasonable estimate of the capital costs to purchase diesel RICE meeting Tier 4 standards. This data was collected in 2010, and thus presumably reflects a 2010 $ cost basis.[453] CARB provided an average cost per horsepower of Tier 4 engines installed with DPF and SCR as follows:

Table 31. Average Cost Per Horsepower for Diesel RICE Meeting Tier 4 Final Requirements[454]

HP RANGE	$/HP FOR NEW ENGINES MEETING TIER 4 FINAL STANDARDS (2010 $)
50-174	$250
175-749	$184
750-1,206	$160
1,207-2,000	$155
>2,000	$125

With this average cost per horsepower data, the average cost effectiveness of replacing an older engine with a Tier 4-compliance diesel engine can be estimated. For the purpose of this cost effectiveness analysis, a 10-year useful life was assumed. The useful life for the emissions warranty guarantee period required in EPA's nonroad diesel engine rules is only 10 years.[455] While we contend that it is likely a RICE unit including such an engine with SCR installed, can have a useful life of 20 years or more, it is not as clear that the diesel particulate filter would have a life of more than 10 years.[456] Thus, for the purpose of this cost effectiveness analysis, a 10 year life of the new Tier 4 engines was assumed. A 5.5% interest rate was also assumed to be consistent with EPA's Control Cost Manual which recommends use of the bank prime interest rate.[457] The bank prime rate fluctuates over time, and the highest it has been in the past 5 years is 5.5%.[458] Reductions in NOx and PM emissions with the replacement of existing diesel RICE with Tier 4 engines were based on the emission factors reflected in Table 30 above. Given that the Tier 4 engines have significantly lower emissions of both NOx and PM, the total of NOx plus PM emissions reduced were considered in calculating cost effectiveness. The table below provides the cost effectiveness of replacing either a pre-1998 or a Tier 1, 2, or 3 engine with a Tier 4 engine. Calculations were done assuming that the engines operate at two different levels: 1,000 hours per year and 4,000 hours per year. EPA assumed 1,000 hours per year in cost analyses done for stationary diesel engines in its 2010 Control Techniques Document for Stationary Diesel Engines.[459] However, EPA also presented information from other sources indicating the average operating hours of diesel RICE are as high as 3,790 hours per year.[460] Thus, a 4,000 hour operating level was assumed to capture the upper end capacity factor of diesel RICE.

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[453] *Id.* at B-11 and B-20.
[454] *Id.*, Table B-6.
[455] *See* 40 CFR 89.014.
[456] *See*, e.g., EPA Technical Bulletin, Diesel Particulate Filter General Information, *available at:* https://www.epa.gov/sites/production/files/2016-03/documents/420f10029.pdf.
[457] U.S. EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.
[458] *See,* e.g., https://fred.stlouisfed.org/series/DPRIME.
[459] *See* EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 56.
[460] *Id.* at 56 (Table 5-1).

Table 32. COST EFFECTIVENESS OF REPLACING EXISTING DIESEL RICE WITH TIER 4-COMPLIANT DIESEL RICE (2010$).

ENGINE SIZE, HP	ANNUALIZED COST OF NEW ENGINE[461]	ENGINE REPLACED WITH TIER 4	COST EFFECTIVENESS OF REPLACEMENT, 1,000 OPERATING HOURS/YR, $/TON of NOx+PM REMOVED (2010$)	COST EFFECTIVENESS OF REPLACEMENT, 4,000 OPERATING HOURS/YR, $/TON of NOx+PM REMOVED (2010$)
75	$2,488	Tier 0	$6,544/TON	$1,636/TON
		Tier 1	$9,921/TON	$2,480/TON
		Tier 2	$15,517/TON	$3,879/TON
		Tier 3	$107,526/TON	$26,882/TON
174	$4,247	Tier 0	$2,610/TON	$653/TON
		Tier 1	$4,011/TON	$1,003/TON
		Tier 2	$5,794/TON	$1,448/TON
		Tier 3	$9,466/TON	$2,367/TON
600	$14,647	Tier 0	$2,610/TON	$653/TON
		Tier 1	$4,034/TON	$1,009/TON
		Tier 2	$5,646/TON	$1,412/TON
		Tier 3	$9,466/TON	$2,367/TON
750	$15,920	Tier 0	$3,147/TON	$787/TON
		Tier 1	$6,164/TON	$1,541/TON
		Tier 2	$12,368/TON	$3,092/TON
		Tier 3	$256,280/TON	$64,070/TON
1500 GEN SETS[462]	$30,845	Tier 0	$2,255/TON	$564/TON
		Tier 1	$3,534/TON	$883/TON
		Tier 2	$5,026/TON	$1,256/TON
		Tier 3	$8,760/TON	$2,190/TON

Because the NOx emission rates of the various Tier 1–4 standards did not always decrease to the same extent for the smallest and the mid-size to large (non-Gen Set) engines, the cost effectiveness of replacing an existing engine with a Tier 4 engine of 75 hp and of 750 hp increases significantly between installing a Tier 4 engine to replace a Tier 0, 1, or 2 engine as compared to a Tier 3 engine. Also, as would be expected, it is generally more cost effective to replace an engine that operates 4,000 hours per year compared to one that operates 1,000 hours per year. In any event, as Table 32 demonstrates, it should at least be considered cost effective to replace a Tier 0 or Tier 1 engine with a Tier 4 engine of any size or operating hours. For engines in the range of 174 hp to less than 750 hp that operate 4,000 hours or more per year, it is also clearly cost effective to replace any tier engine with a Tier 4 engine, as it also is cost effective for large generator set engines.

[461] Based on the costs per horsepower given in Table 31 above and a capital recovery factor based on a 10-year life and a 5.5% interest rate of 0.132668.

[462] Generator sets > 1,200 hp have more stringent Tier 4 emission standards than other engines that are greater than 750 hp. *See* May 2004, EPA Regulatory Announcement, Clean Air Nonroad Diesel Rule, Table 1.

Although the above review focused on the cost effectiveness for the combined reductions of NOx plus PM, it is important to note that the EPA nonroad engine requirements also set emission limits on THC. Specifically, the Tier 4 standards set a THC emission limit that reflects an 87% reduction in THC compared to pre-1998 (Tier 0 levels). Further, only ULSD is to be used on Tier 4 engines. That is not only a legal requirement but, as discussed above, it is technically required by the manufacturer to ensure that the CDPF works effectively. The use of ULSD which is 15 ppm sulfur, compared to diesel fuel which may be 500 ppm sulfur, reflects a 97% reduction in SO2 emissions from diesel RICE. The increased costs for using ULSD are estimated to be $0.07 more per gallon, but the costs would be reduced to $0.04 per gallon due to anticipated savings because of decreased RICE maintenance with the use of low sulfur fuel.[463] Some states may already mandate the use of ULSD or it could be that ULSD is the only fuel available in some areas, so installation of a Tier 4 engine may not necessarily reduce SO2 emissions for all sources.

In terms of the non-air quality environmental and energy impacts associated with the replacement of an older engine with a Tier 4 engine, the impacts associated with the pollution controls could include increased fuel consumption due to reduced efficiency/parasitic load of SCR and CDPF and/or result in reduced power output. However, improvements in combustion efficiency that have been required and engineered into these newer engines also mean fuel savings that will make up for any parasitic loads, particularly for Tier 0 or Tier 1 engines replaced with Tier 4 engines. Other environmental impacts include solid waste disposal issues from spent catalysts. Further, the Tier 4 engines will require operator training and may result in increased maintenance, although the switch from higher sulfur diesel to ULSD which is mandated for use in Tier 4 engines will result in decreased maintenance. One likely benefit regarding maintenance associated with these controls when purchasing an engine with the NOx and PM controls built into the design as one package (as comparted to retrofitting an existing engine) is that the manufacturers will have a standard set of operating and maintenance procedures for each engine, whereas for a retrofit of SCR and/or CDPF to an existing diesel RICE, the operating and maintenance procedures will presumably need to be tailored to the specific make, model, and condition of the existing engine.

There are also other environmental benefits of replacing existing diesel engines with Tier 4 engines, particularly due to effects that increased engine efficiency and the use of a CDPF will have on reducing black carbon emissions from diesel RICE. Black carbon is very effective at absorbing solar energy. The black carbon particles in the atmosphere absorb solar energy and thus can warm the planet, although black carbon is considered a short-lived climate change pollutant.[464] And when the black carbon particles precipitate to surfaces of snow and ice, it reduces the reflecting power of the snow or ice which results in increased melting of snow and ice. The increased melting of the snow and ice results in a feedback loop with more land exposed to absorb, rather than reflect, solar energy, melting more snow and ice as well as permafrost that releases carbon trapped in the soils which further adds to climate change pollution.[465] Thus, the reduction in black carbon emissions by switching older diesel RICE with Tier 4 engines could have climate change benefits as well as visibility benefits.

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[463] *See* https://dieselnet.com/standards/us/nonroad.php.

[464] *See* https://oehha.ca.gov/epic/climate-change-drivers/atmospheric-black-carbon-concentrations; *see also* Cho, Renee, The Damaging Effects of Black Carbon, March 22, 2016, Earth Institute, Columbia University, *available at*: https://blogs.ei.columbia.edu/2016/03/22/the-damaging-effects-of-black-carbon/.

[465] *Id. See also* https://scied.ucar.edu/shortcontent/melting-ice-and-climate-change.

Given that manufactures were required to exclusively produce Tier 4 nonroad diesel engines by January 1, 2015, the Tier 4 engines should be readily available for purchase and installation, or be available in fairly short order. Thus, the replacement of an existing diesel RICE with a Tier 4 diesel RICE should presumably be able to be completed within six months to one year.

When EPA adopted the nonroad diesel engine emission standards, EPA envisioned that the nonroad diesel engine fleet would be comprised entirely of Tier 4 engines by 2030.[466] It is not clear whether the diesel RICE used in the oil and gas industry are on track to be operating on Tier 4 engines by 2030. As part of the process of evaluating controls to achieve reasonable progress towards the national visibility goal, States should evaluate the age and EPA emission compliance status (i.e., Tier) of existing diesel RICE operating within the oil and gas industry in the state. If states do not already collect such information, states should gather this information through required source inventory and/or source registration or licensure requirements.

It is clear that requiring replacement of existing diesel RICE with Tier 4 RICE engines is a cost effective control to reduce NOx and PM along with VOCs and SO_2 for many size engines in a range of operating hours. Requiring the replacement of existing diesel RICE with new Tier 4 engines along with requiring the use of ULSD fuel is the most readily implementable approach to reducing visibility-impairing emissions from diesel RICE.

It would be most effective to require use of Tier 4-compliant generator sets in conjunction with electric motors for all drilling operations, because large Gen Sets (which would be necessary to power electric drill rigs) are subject to much more stringent NOx limits than large diesel RICE (i.e., 0.5 g/hp-hr is the NOx limit for Tier 4 engines, compared to the 2.60 g/hp-hr NOx limit for large diesel RICE, as shown in Table 30 above). Indeed, the Superintendent of Carlsbad National Park has requested this approach as a mitigation measure for the Chevron U.S.A. Hayhurst Master Development Plan for which the western boundary of the project area was to be located only 17 kilometers from Carlsbad National Park in New Mexico. Specifically, the National Park Service stated that "[i]f this option were implemented, engines would meet the 0.5 g NOx/hp-hr [limit] and would reduce drilling and completion emissions by 90%."[467]

In summary, for stationary diesel RICE units, states should require the replacement of older existing engines with Tier 4 engines. For those diesel RICE that are considered nonroad engines, states should consider adopting emission requirements for diesel nonroad engines if California has adopted emission standards that have been approved by EPA under Section 209(e)(2) of the Clean Air Act, where the state adopts the same standards. Alternatively, a state can incentivize the replacement of existing nonroad engines with Tier 4 engines. Further, the state should otherwise encourage use of electric engines for drill rigs and the use of Tier 4 Gen Sets to power those electric engines, as that will result in the greatest reduction in NOx due to the lower emission limits that apply to Tier 4 Generator Set engines. States should evaluate all available options to, at the minimum, encourage replacement of older existing nonroad engines with Tier 4 engines.

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[466] *See*, e.g., EPA Progress Report on EPA's Nonroad Mobile Source Emissions Reductions Strategies, September 27, 2006, at 8, *available at:* https://www.epa.gov/sites/production/files/2015-11/documents/20060927-2006-p-00039.pdf.

[467] *See* August 29, 2016 Memorandum from Doug Neighbor, Superintendent, Carlsbad Caverns National Park, to Paul Murphy, Project Lead, Bureau of Land Management, Carlsbad Field Office, at 6.

2. REPLACEMENT OF EXISTING DIESEL-FIRED RICE WITH NATURAL GAS-FIRED RICE

A second option for reducing emissions from diesel RICE is to replace the engines with natural gas-fired or dual-fuel RICE. This was another mitigation measure recommended by the National Park Service to the Bureau of Land Management for the Chevron U.S.A. Hayhurst Master Development Plan. Specifically, the National Park Service stated: "[b]oth natural gas-fired and dual-fuel engines have proven to be feasible, cost effective options for drilling operations in various basins throughout the United States and Canada [fn omitted]."[468] The National Park Service gave numerous examples of companies employing natural gas-fired or dual-fuel drill rig engines, including "EQT, Apache Corporation, Chesapeake Energy, Statoil, Encana Corporation, Cabot Oil and Gas, Antero Resources, CONSOL Energy and Seneca Resources."[469] The National Park Service specifically highlighted Chesapeake Energy's move to "transition all of its hydraulic fracturing equipment to [liquefied natural gas]."[470]

The Four Corners Air Quality Task Force (4CAQTF) also evaluated this option of using natural gas-fired engines on the drill rigs in the Four Corners region.[471] The 4CAQTF found that this switch from diesel RICE to lean burn RICE engines would result in approximately a 91% reduction in NOx from use of Tier 0 diesel engines and approximately an 85% reduction in NOx from use of Tier 1 diesel engines, but this was based on an assumed NOx emission rate from lean burn natural gas-fired RICE of 2 to 3 g/hp-hr.[472] As discussed in Section II.D. and E. of this report, use of LEC or SCR at lean burn engines is cost effective for lean-burn RICE and could achieve NOx emission rates of no higher than 2 g/hp-hr and more likely 1 g/hp-hr or even lower. Use of natural gas-fired RICE instead of diesel RICE would also significantly reduce SO_2 and PM emissions. The 4CAQTF report found that use of natural gas-fired RICE may be less expensive than diesel RICE if natural gas is located within close proximity and able to be piped to the natural gas-fired RICE.[473] Diesel fuel generally needs to be hauled to the drill rig, thus replacement of diesel RICE with natural gas-fired RICE would also reduce mobile source tailpipe and fugitive emissions associated with transporting the diesel fuel. The 4CAQTF report gave one example of a natural gas-fired drill rig being utilized in the Jonah Field in Wyoming to indicate that the use of natural gas-fired drill rigs is a technically feasible option,[474] which is clearly the case given the number of companies cited by the National Park Service that are employing natural gas-fired or dual-fuel drill rig engines.[475] The 4CAQTF indicated a capital cost of up to $1.2 million dollars per rig for the retrofit.[476] Some of the negative impacts included that the use of natural gas-fired RICE would increase carbon monoxide emissions by

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[468] *Id.* at 7.
[469] *Id.*
[470] *Id.*
[471] See Four Corners Air Quality Task Force, Report of Mitigation Options, November 1, 2007, at 61, *available at:* https://www.env.nm.gov/wp-content/uploads/sites/2/2016/11/4CAQTF_Report_FINAL.pdf.
[472] *Id.*
[473] *Id.*
[474] *Id.* at 62.
[475] *See* August 29, 2016 Memorandum from Doug Neighbor, Superintendent, Carlsbad Caverns National Park, to Paul Murphy, Project Lead, Bureau of Land Management, Carlsbad Field Office, at 7.
[476] *Id.*

approximately 175%, and also that there could be increased land disturbance regarding the installation of natural gas pipelines for delivery of fuel.[477]

In summary, replacement of diesel RICE with natural gas-fired RICE is a viable control option for addressing the visibility-impairing emissions from diesel RICE that states should consider in evaluating reasonable progress measures for diesel RICE units.

3. RETROFIT OF DIESEL-FIRED RICE WITH AIR POLLUTION CONTROLS

Another option to control emissions from stationary diesel RICE is to require retrofits of specific pollution controls. Provided below are cost effectiveness analyses for SCR retrofits and for DPF retrofits to diesel RICE.

a) RETROFITTING SCR TO EXISTING DIESEL-FIRED RICE TO REDUCE NOx

EPA's 2010 Alternative Control Techniques Document for Stationary Diesel RICE presented control costs for SCR and for CDPF retrofits at diesel RICE units. For SCR, EPA estimated capital costs at $98 per hp, based on industry data, and this included costs for the catalyst, reactor housing and ductwork, ammonia injection system, controls, and engineering and installation of the equipment.[478] EPA estimated annualized costs for SCR at $40 per hp, based on annualized capital costs and costs for operating/supervisory labor, maintenance, ammonia, steam diluent, and fuel penalty calculated using the EPA Control Cost Manual and based on 1,000 hours of operation per year.[479]

EPA's cost data for the 2010 Alternative Control Techniques document for Stationary Diesel RICE assume 90 percent reduction of NOx emissions from SCR, which should be readily achievable.[480] EPA estimates uncontrolled NOx emissions based on emission factors from modeling for the different tiers of EPA's exhaust emission standards for nonroad engines: (1) Tier 0 Standards (pre-1998); (2) Tier 1 Standards (1998-2003); (3) Tier 2 Standards (2004-2007); and Tier 3 Standards (2006-2010). As discussed above, the Tier 4 standards reflect the NOx control levels achievable with SCR, and thus it would not make sense for EPA to evaluate SCR retrofits for a Tier 4 engine.

The following table shows the cost effectiveness, based on EPA's cost data, of retrofitting SCR to an uncontrolled stationary diesel RICE and to a Tier 1, 2, or 3 diesel RICE operating 1,000 hours per year and 4,000 hours per year using EPA uncontrolled NO_x emissions estimates. EPA assumed 1,000 hours per year in cost analyses done for stationary diesel engines in its 2010 Control Techniques Document for Stationary Diesel Engines.[481] However, EPA also presented information from other sources indicating the average operating hours of diesel RICE as high as 3,790 hours per year.[482] Thus, a 4,000 hour operating level was assumed to capture the upper end capacity factor of diesel RICE. To estimate operating costs for operating at 4,000 hours per year, EPA's annual cost estimates for an engine

[477] *Id.* at 61-62.
[478] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 57.
[479] *Id.*
[480] *Id.*
[481] *See* EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 56.
[482] *Id.* at 56 (Table 5-1).

operating 1,000 hours per year were multiplied by a factor of four to estimate potential annual costs reflective of engines operating closer to 4,000 hours per year. For the cost effectiveness analysis presented herein, the SCR system was assumed to have a life of 20 years. EPA states that SCRs at boilers, refineries, industrial boilers, etc. have a useful life of 20-30 years.[483] To be consistent with EPA's statements on SCR and also considering the useful life of diesel RICE, this analysis will assume a 20-year life of the SCR. A 5.5% interest rate was used to be consistent with EPA's Control Cost Manual which recommends use of the bank prime interest rate.[484]

Table 33. Cost Effectiveness to Reduce NOx Emissions by 90% from Stationary Diesel RICE with SCR Operating 1,000 Hours per Year and 4,000 Hours per Year[485]

ENGINE SIZE, hp	ANNUALIZED COSTS OF SCR, 2005$	EMISSIONS STANDARD	COST EFFECTIVENESS OF SCR, 1,000 HOURS PER YEAR, 2005$	COST EFFECTIVENESS OF SCR, 4,000 HOURS PER YEAR, 2005$
75	$2,808	TIER 0	$5,474/ton	$4,575/ton
		TIER 1	$6,739/ton	$5,632/ton
		TIER 2	$8,021/ton	$6,703/ton
		TIER 3	$12,581/ton	$10,514/ton
238	$8,911	TIER 0	$4,500/ton	$3,761/ton
		TIER 1	$6,781/ton	$5,667/ton
		TIER 2	$9,430/ton	$7,881/ton
		TIER 3	$15,093/ton	$12,614/ton
675	$25,272	TIER 0	$4,500/ton	$3,761/ton
		TIER 1	$6,485/ton	$5,420/ton
		TIER 2	$9,207/ton	$7,694/ton
		TIER 3	$15,097/ton	$12,617/ton
1,000	$37,441	TIER 0	$4,497/ton	$3,759/ton
		TIER 1	$6,500/ton	$5,432/ton
		TIER 2	$9,204/ton	$7,692/ton
		TIER 3	$15,073/ton	$12,597/ton

[483] *See* EPA's Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 80.
[484] U.S. EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.
[485] *See* EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 58, Table 5-2. Annualized costs of control were based on a 20-year life and a 5.5% interest rate. NOx emission reductions are based on 90% NOx removal efficiency, with uncontrolled emissions based on EPA estimates (EPA-420/P-04-09, 2004).

Lower cost data were reported by EPA in its 2000 Updated Information on NOx Emissions and Control Techniques for what it referred to then as 'modern SCR': "The vendor carried out a similar analysis for a 1,000 bhp diesel engine. For an engine operating 200 hours per year, the cost effectiveness was calculated at almost $4,000 per ton. For an engine operating 2,000 hours per year, the cost effectiveness dropped to less than $900 per ton."[486]

In its 1993 Alternative Control Techniques Document for RICE, EPA included a cost effectiveness analysis for diesel-fueled RICE with SCR operating 8,000 hours per year with costs as low as $690/ton for the largest engine sizes (4,000-8,000 hp). EPA noted costs of $1,000/ton or less for engines larger than 3,200 hp and costs of $3,000/ton or less for engines larger than 750 hp.[487]

It is clearly cost effective to retrofit SCR to diesel RICE units that emit NOx at levels similar to the older tier nonroad engines (*e.g.*, Tiers 0 or 1) even at low levels of operating hours per year. And, diesel RICE used in the oil and gas industry have been retrofitted with SCR to reduce NOx. For example, the state of Wyoming and the Bureau of Land Management coordinated with companies drilling in the Pinedale Anticline in western Wyoming to reduce NOx emissions from all drill rigs and, as a result, Shell Exploration and Production Company retrofitted 21 drill rigs with SCRs that have achieved 91-99% reduction in NOx emissions with low levels of ammonia slip (averaging 2-3 ppm).[488] There are several examples of successful SCR retrofits to diesel RICE, including for stationary diesel electrical generating sets and backup generators.[489]

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[486] EPA 2000 Updated Information on NOx Emissions and Control Techniques at 5-13 referencing the following document: Manufacturers of Emission Controls Association. *Urea SCR for Stationary IC Engines*. Slides from a presentation to the NESCAUM Stationary Source and Permits Committee. October 6, 1999.

[487] *See* EPA's 1993 Alternative Control Techniques Document for RICE at 2-38 and Table 2-14 at 2-42.

[488] *See* Manufacturers of Emission Controls Association, Case Studies of Reciprocating Diesel Engine Retrofit Projects, November 2009, at 7 (Section 2.4), *available at:* http://www.meca.org/galleries/files/Stationary_Engine_Diesel_Retrofit_Case_Studies_1109final.pdf. *See also* Johnson Matthey, New system helps control NOx for Shell drill rigs, Pinedale Online, October 28, 2008, *available at:* http://www.pinedaleonline.com/news/2008/10/Newsystemhelpscontro.htm; and Johnson Matthey Catalysts, Application Fact Sheet, Case No. 801: Controlling NOx from Gas Drilling Rig Engine s with Johnson Matthey's Urea SCR System, *available at:* https://www.jmsec.com/fileadmin/user_upload/pdf/application_fact_sheets/engines/application_fact_sheet_801_-_shell_gas_drill_rig.pdf.

[489] *See* Manufacturers of Emission Controls Association, Case Studies of Reciprocating Diesel Engine Retrofit Projects, November 2009, at 14, 5-7 and 12.

The environmental and energy impacts of SCR systems for diesel RICE include the following:

- 0.5 percent increase in fuel consumption for SCR and associated air emissions increases[490]
- 1 to 2 percent reduction in power output for SCR[491]
- Increased solid waste disposal from spent catalysts[492]
- If ammonia is used instead of urea (which is assumed to be the reagent used in the SCR cost analyses presented above), there would be an increased need for risk management and implementation and associated costs.[493] If urea or aqueous ammonia is used as the reagent, the hazards from the use of pressurized anhydrous ammonia do not apply. It is likely that urea is the most common reagent used in SCR for diesel RICE

SCR technology is widely used at many industrial sources. There are typically not overarching non-air quality or energy concerns with this technology, and many of the concerns are addressed in the cost analysis.

In terms of length of time to install SCR, EPA has estimated that it takes 28-58 weeks to install SCR at a diesel-fired (lean-burn) RICE unit.[494]

b) RETROFITTING CDPF TO DIESEL-FIRED RICE TO REDUCE PM AND VOCS

For CDPF, EPA estimated capital and annual costs in its 2010 Alternative Control Techniques Document for Stationary Diesel RICE based on cost equations developed for the RICE NESHAP. EPA's analysis was based on 2008 cost data from stationary diesel RICE retrofits. The following linear equation for annual cost includes annual operating and maintenance costs plus annualized capital costs based on a 7% interest rate and 10-year life of controls:

CDPF Annual Cost = 11.6 x ENGINE HP + 1,414 (2008$)

The capital cost equation for retrofitting a CDPF on a diesel engine was determined by EPA to be:

CDPF Capital Cost = 63.4 x ENGINE HP + 5,699 (2008$)

These relationships are derived from a data set that includes engines ranging from 40–1,400 hp.[495] EPA's cost estimates are based on 1,000 hours of operation per year.[496]

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[490] *See* EPA 1993 Alternative Control Techniques Document for RICE, 2-23 (Table 2-11).

[491] *Id.* at 2-23 (Table 2-11).

[492] Colorado Department of Public Health and Environment, Air Pollution Control Division, Reasonable Progress Evaluation for RICE Source Category at 10 (citing EPA (2002), EPA Air Pollution Control Cost Manual, 6th ed., EPA/452/B-02-001, U.S. EPA, Office of Air Quality Planning and Standards, RTP).

[493] Anhydrous ammonia is a gas at standard temperature and pressure, and so it is delivered and stored under pressure. It is also a hazardous material and typically requires special permits and procedures for transportation, handling, and storage. *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 15.

[494] 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls at 15.

[495] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 59.

[496] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 61.

EPA's cost data for the 2010 Alternative Control Techniques document for Stationary Diesel RICE assume 90 percent reduction of PM emissions from CDPF.[497] EPA estimates uncontrolled PM emissions based on emission factors from nonroad engine modeling for the different tiers of EPA's exhaust emission standards for nonroad engines: (1) Tier 0 Standards (pre-1998); (2) Tier 1 Standards (1998-2003); (3) Tier 2 Standards (2004-2007); and Tier 3 Standards (2006-2010). In 2004, EPA adopted Tier 4 Standards, which were to be phased-in from 2008 to 2015. The Tier 4 Standards require 90 percent reduction of PM and NOx emissions. According to EPA, "[t]hese emission reductions can be achieved through the use of control technologies, including advanced exhaust gas aftertreatment, similar to those required by the 2007-2010 standards for highway engines."[498]

The following table shows the results of a cost analysis, based on EPA's cost data, of retrofitting CDPF to an uncontrolled stationary diesel RICE operating 1,000 hours per year and 4,000 hours per year using EPA uncontrolled PM emissions estimates. For this cost analysis of CDPF, a 10-year life and 5.5% interest rate. As discussed above, while we contend that it is likely a RICE unit can have a useful life of 20 years, it is not as clear that the diesel particulate filter would have a life of more than 10 years.[499] Therefore, a useful life of a CDPF retrofit was assumed to be 10 years in determining annualized costs of CDPF. A 5.5% interest rate was also assumed to be consistent with EPA's Control Cost Manual which recommends use of the bank prime interest rate.[500] To estimate annual operating costs for operation of CPDF at 4,000 hours per year, EPA's annual cost estimates which were based on 1,000 operating hours per year were multiplied by a factor of four.

[497] *Id.*
[498] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 22.
[499] *See*, e.g., EPA Technical Bulletin, Diesel Particulate Filter General Information, *available at:* https://www.epa.gov/sites/production/files/2016-03/documents/420f10029.pdf.
[500] U.S. EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.

Table 34. Cost Effectiveness to Reduce PM Emissions by 90% from Stationary Diesel RICE with CDPF Operating 1,000 Hours per Year and 4,000 Hours per Year[501]

ENGINE SIZE, hp	ANNUALIZED COSTS OF CDPF, 2008$	EMISSIONS STANDARD	COST EFFECTIVENESS OF CDPF, 1,000 HOURS PER YEAR, 2008$	COST EFFECTIVENESS OF CDPF, 4,000 HOURS PER YEAR, 2008$
75	$1,670	TIER 0	$31,088/ton	$10,155/ton
		TIER 1	$47,467/ton	$15,505/ton
		TIER 2	$93,735/ton	$30,619/ton
		TIER 3	$74,837/ton	$24,445/ton
238	$2,955	TIER 0	$31,265/ton	$10,510/ton
		TIER 1	$49,665/ton	$16,696/ton
		TIER 2	$95,155/ton	$31,988/ton
		TIER 3	$83,321/ton	$28,010/ton
675	$6,397	TIER 0	$23,774/ton	$8,150/ton
		TIER 1	$43,343/ton	$14,860/ton
		TIER 2	$72,608/ton	$24,892/ton
		TIER 3	$63,467/ton	$21,759/ton
1,000	$8,958	TIER 0	$22,468/ton	$7,740/ton
		TIER 1	$40,960/ton	$14,110/ton
		TIER 2	$68,644/ton	$23,646/ton
		TIER 3	$59,960/ton	$20,654/ton

It must be noted that the higher cost effectiveness values for CDPF in comparison to SCR cost effectiveness values are due to the magnitude of PM emissions from diesel RICE being much lower than the NOx emissions from diesel RICE. The capital costs of CDPF range from $10,000 to $70,000, which is somewhat lower than the range of capital costs for SCR (which range from $7,300 to $100,000), and the annual operating costs of CDPF are significantly lower than the operating costs of SCR ($800-$3,200 per

[501] *See* EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 58, Table 5-2. Annualized costs of control were calculated assuming a 10-year life of controls and a 5.5% interest rate. NOx emission reductions are based on EPA's assumed 90% removal efficiency. Uncontrolled NOx emissions are based on EPA estimates (EPA-420/P-04-09, 2004).

year for CDPF compared to $2,200 to $29,000 per year for SCR).[502] Although CDPF can achieve greater than 90% reduction of PM, overall the tons of PM reduced with CDPF is an order of magnitude lower than the NOx emissions reduced with SCR, and thus the cost effectiveness of CDPF is much higher than the cost effectiveness of SCR.

To truly understand whether this control is considered cost effective, one has to evaluate whether similar sources have been required to install the control at similar costs. Indeed, there are several examples of diesel particulate filter systems being retrofitted to diesel RICE.[503]

As previously stated, the use of a CDPF requires the use of ULSD fuel. It should be noted that ULSD is prevalent in the fuel pool today, including in some nonroad fuels that may not be labeled as such, and therefore may already be used in many stationary diesel engines.[504] The use of ULSD which is 15 ppm sulfur, compared to higher sulfur diesel fuel which may be of 500 ppm sulfur content, reflects a 97% reduction in SO_2 emissions from diesel RICE. The increased costs for using ULSD are estimated to be $0.07 more per gallon, but the costs would be reduced to $0.04 per gallon due to anticipated savings because of decreased RICE maintenance with the use of low sulfur fuel.[505] EPA's 2010 Alternative Control Techniques Document for Stationary Diesel RICE estimated that using ULSD fuel would increase fuel costs by only $0.03 to $0.05 per gallon.[506]

The environmental and energy impacts of controls for stationary diesel RICE include the following:

- 1 to 2 percent fuel penalty for CDPF[507]
- Increased solid waste disposal from spent catalysts[508]

The CDPF will have an added benefit of reducing VOCs and associated air toxics. EPA has found that CDPF can reduce THC by 90 percent.[509] Thus, CDPF can be considered a top control technology for both PM and VOCs.

CDPF can be installed fairly quickly. EPA has indicated that diesel particulate filters can be installed in less than a day,[510] although this claim likely pertains to onroad diesel engines (i.e., trucks). Nonetheless, it is the same technology whether applied to a mobile source or a larger generating diesel RICE. It can be assumed that even taking into account time for engineering, design, ordering of parts, etc., the time to install a CDPF is likely under a year.

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[502] These costs reflect the range of capital and operating costs for the engine sizes evaluated in Tables 33 and 34, using EPA's SCR and CDPF cost calculations from its 2010 Alternative Control Techniques Document for Stationary Diesel RICE.
[503] *See* Manufacturers of Emission Controls Association, Case Study of Reciprocating Diesel Engine Retrofit Projects, November 2009, at 6-14.
[504] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 47 and 48.
[505] *See* https://dieselnet.com/standards/us/nonroad.php.
[506] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 71.
[507] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 35.
[508] Colorado Department of Public Health and Environment, Air Pollution Control Division, Reasonable Progress Evaluation for RICE Source Category at 10 (citing EPA (2002), EPA Air Pollution Control Cost Manual, 6th ed., EPA/452/B-02-001, U.S. EPA, Office of Air Quality Planning and Standards, RTP).
[509] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 32 and 34.
[510] *See* https://www.epa.gov/sites/production/files/2016-03/documents/420f10028.pdf.

D. EXAMPLES OF STATE AND LOCAL AIR AGENCY RULES FOR EXISTING DIESEL-FIRED RICE

States and local air agencies have adopted NOx limits for diesel RICE, some of which have been in place for over 20 years. In Table 35 below, we summarize some of the stronger state and local air pollution requirements. Note that this is not a comprehensive list of state and local air regulations for diesel RICE.

California has adopted fleet-wide emission requirements for existing diesel "off-road" (i.e., non-road) diesel-fueled engines of 25 hp or greater (*see* Title 13 California Code of Regulations Sections 2449 through 2449.2), and EPA has authorized those rules under Section 209(e) of the Clean Air Act.[511] The goal of this program is to turnover nonroad diesel RICE to Tier 4 engines. The rule established in-use statewide emission performance standards that apply to any person owning and operating a nonroad diesel engine in California of 25 hp or greater. The fleet requirements phase in over time and require that fleets either meet fleet average emission targets or meet best available control technology (BACT). States may be able to adopt requirements like this for nonroad diesel RICE, pursuant to Section 209(e)(2) of the Clean Air Act.

Table 35 is a summary of the stronger NOx emission limits required of diesel RICE in states and local air districts across the United States. It is important to note that these are limits that generally do not apply to portable or nonroad engines, unless clearly stated otherwise. The most broadly applicable NOx limit required is approximately 1.10 g/hp-hr which applies in several air districts in California, although SCAQMD has adopted a more stringent NOx limit of 0.15 g/hp-hr. Those limits all likely reflect application of SCR to diesel RICE. These limits were adopted generally to meet RACT and BARCT (in California) and, as previously discussed, costs are taken into account in making these RACT and BARCT determinations. Thus, the fact that state and local air agencies have adopted emission limits reflective of SCR indicate that these agencies have found SCR to be a cost effective control to retrofit to existing stationary diesel RICE.

Table 35. State/Local Air Agency Diesel RICE Rules for NOx Emissions[512]

State/Local	Regulation	Applicability	NOx Limit and units[513] (equivalent g/hp-hr)
CA-Bay Area AQMD[514]	Reg. 9, Rule 8 Effective 1/1/2012: >50 bhp &/or not Low Usage (<100 hrs/yr) &/or not registered as portable:	51 to 275 bhp	180 ppmvd (2.47 g/hp-hr)
		>175 bhp	110 ppmvd (1.51.g/hp-hr)

[511] 78 Fed. Reg. 58090-58121 (Sept. 20, 2013).
[512] This table attempts to summarize the requirements and emission limits of State and Local Air Agency rules, but the authors recommend that readers check each specific rule for the details of how the rule applies to different units, and in case of any errors in this table.
[513] Emission limits that are in ppmvd are at @ 15% oxygen.
[514] http://www.baaqmd.gov/~/media/dotgov/files/rules/reg-9-rule-8-nitrogen-oxides-and-carbon-monoxide-from-stationary-internal-combustion-engines/documents/rg0908.pdf?la=en.

State/Local	Regulation	Applicability	NOx Limit and units[513] (equivalent g/hp-hr)
CA-Mojave Desert APCD[515]	Rule 1160 (Amended 1/22/18)	>50 bhp &/or >100 hours/4 quarters, not portable, not subject to Airborne Toxic Control Measure, and only if located in the Federal Ozone Nonattainment area	80 ppmv (1.09 g/hp-hr)
CA-Sacramento AQMD[516]	Rule 412	>50 bhp with exemptions if portable, or if operated less than certain # of hours which vary based on rating of engine	80 ppmv (1.10 g/hp-hr) Alt Limit: 90% NOx reduction
CA-San Joaquin Valley APCD[517]	Rule 4702 Exemptions for <50 bhp, portable, or low use engines Non-EPA certified Compression Ignition Engines installed on or before 6/1/06. ---------- Applicable to EPA-certified CI Engines	>50 & ≤ 500 bhp	EPA Tier 3 or Tier 4 by 1/1/2010
		>500 & ≤750 bhp and < 1000 hrs/yr	EPA Tier 3 by 1/1/2010
		>750 bhp & < 1000 hrs/yr	EPA Tier 4 by 7/1/2011
		>500 bhp & ≥1000 hrs/yr	80 ppmv (1.10 g/hp-hr)
		EPA Tier 1 or 2 engine	EPA Tier 4 by 1/1/2015 or 12 years after install date, but no later than 6/1/2018.
		EPA Tier 3 or Tier 4 engine	Meet certified CI engine standard at time of installation
SCAQMD[518]	Rule 1110.2 As amended 11/1/2019	>50 bhp and not nonroad engines or portable (except portable generators that provide primary or supplemental power to a building, facility,	11 ppmvd (0.15 g/hp-hr)

[515] https://ww3.arb.ca.gov/drdb/moj/curhtml/r1160.pdf.
[516] http://www.airquality.org/ProgramCoordination/Documents/rule412.pdf.
[517] https://ww3.arb.ca.gov/drdb/sju/curhtml/r4702.pdf.
[518] http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1110-2.pdf.

State/Local	Regulation	Applicability	NOx Limit and units[513] (equivalent g/hp-hr)
		stationary source, or stationary equipment, which are not exempt from the NOx limit)	
CA- Ventura County AQMD[519]	Rule 74.9	>50 bhp & > 200 hrs/yr Does not apply to diesel engines with permitted capacity factor ≤ 15%	80 ppmvd (1.10 g/hp-hr) or 90% NOx reduction
TX- Houston-Galveston-Brazoria Area[520]	30 TAC 117.2010(c)(2) Emission Specs for 8hr ozone demo The following limits apply to "stationary engines" (stays at same location more than 12 months) operated more than 100 hours per year on average, that were placed into service after 10/1/01, that were installed, modified, reconstructed, or relocated on or after the date specified:	≥50hp & <100 hp, on or after 10/1/2007	3.3 g/hp-hr
		≥100 hp & <750 hp, On or after 10/1/2006	2.8 g/hp-hr
		≥750 hp, On or after 10/1/2005	4.5 g/hp-hr
		≥300 hp & < 600 hp, On or after 10/1/2005	2.8 g/hp-hr
TX- Dallas -Ft. Worth Area[521]	30 TAC 117.2110(3) Emission Specs for 8hr ozone demo The following limits apply to "stationary" diesel engines (stays at same location more than 12 months) operated more than 100 hours per year on average, that were placed into service after	≥50hp & <100 hp, on or after 3/1/2009	3.3 g/hp-hr
		≥100 hp & <750 hp, On or after 3/1/2009	2.8 g/hp-hr
		≥750 hp, On or after 3/1/2009	4.5 g/hp-hr

[519] http://www.vcapcd.org/Rulebook/Reg4/RULE%2074.9.pdf.
[520] https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=117&rl=2010.
[521] http://txrules.elaws.us/rule/title30_chapter117_sec.117.2110.

State/Local	Regulation	Applicability	NOx Limit and units[513] (equivalent g/hp-hr)
	3/1/09, that were installed, modified, reconstructed, or relocated on or after the date specified:	Alternative limit to above for units with an annual capacity factor of ≤.0383	0.060 lb/MMBtu
MI[522]	R 336.1818 Applies to stationary engines	>1 ton/day NOx engines per avg ozone control period day in 1995	2.3 g/bhp-hr
NY[523]	6 CCR-NY 227-2.4 (f)(3) Applies to stationary engines	≥ 200 bhp in a severe ozone nonattainment area or ≥400 bhp outside a severe NAA	2.3 g/bhp-hr
WI[524]	NR 428.22(1)(i) Exemptions for low operating unit engines or for engines certified to meet federal nonroad emission standards.	≥500 hp	2.0 g/bhp-hr
MO[525]	10 CSR 10-5.510(3)(D)3.B. Applies in St. Louis ozone nonattainment area, to installations with potential to emit ≥100 tpy that operate more than 750 hours annually or more than 400 hours during ozone season	≥1800 hp	2.5 g/hp-hr
OH[526]	OAC Chapter 3745-110-03(F)(3) Applies in counties around Cleveland ozone nonattainment	≥2,000 hp	3.0 g/hp-hr

[522] https://www.michigan.gov/documents/deq/deq-aqd-air-rules-apc-part8_314769_7.pdf.
[523] https://govt.westlaw.com/nycrr/Document/I4e978e48cd1711dda432a117e6e0f345?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default).
[524] http://docs.legis.wisconsin.gov/code/admin_code/nr/400/428.pdf.
[525] https://www.sos.mo.gov/cmsimages/adrules/csr/current/10csr/10c10-5.pdf.
[526] https://www.epa.ohio.gov/portals/27/regs/3745-110/3745-110-02_Final.pdf.

State/Local	Regulation	Applicability	NOx Limit and units[513] (equivalent g/hp-hr)
	area, to stationary engines at a facility with potential to emit ≥100 tpy		

E. SUMMARY – CONTROL OPTIONS FOR DIESEL-FIRED RICE UNITS

Based on all of the analysis provided above, there are several options for reducing visibility-impairing emissions from diesel-fired RICE units. These options are as follows, in order of most beneficial for reducing visibility-impairing pollutants from this source category:

1) Replace existing older diesel-fired engines with Tier 4 engines.

   Replacement of existing older diesel-fired RICE with Tier 4 engines is cost effective as shown in Table 32 above, and has the benefit of reducing NOx by 49% to 96% and PM by 81% to 97.5% (with the percentage reduction based on the emission rates the existing engines is complying with). Replacement of older diesel RICE with Tier 4 engines will also result in a reduction in VOC emissions, due to the VOC emission limits required of Tier 4 engines, and it will also reduce SO_2 emissions because ULSD fuel is required for Tier 4 engines.

   The cost effectiveness of replacing existing diesel-fired RICE varies based on the size of the engine being replaced (smaller engines and larger engines that are not electrical generating sets have less stringent Tier 4 emission limits, which impacts cost effectiveness for those engines, and also the annual operating hours impact cost effectiveness). In general, as demonstrated in Table 32 above, it is cost effective to replace a Tier 0 or Tier 1 engine with a Tier 4 engine for any size engine including for those engines operating on the lower end of annual operating hours.

   For drill rigs, it is most preferable from an air emissions perspective to replace existing older diesel-fired drill rigs with electric-motor drill rigs that are powered by a Tier 4 Electrical Generating Set. Tier 4 Electrical Generating Set engines greater than 1,500 hp are required to meet the lowest NOx and PM emission rates, significantly lower than large non-electrical generating engines (as shown in Table 30 above). Thus, installing electric drill rigs that are powered by Tier 4 electrical generating diesel RICE will result in the greatest reduction in visibility-impairing emissions if the only option is to continue to power the engines with diesel fuel.

2) Replace existing diesel-fired RICE with natural gas-fired RICE equipped with LEC or SCR. Replacing existing older diesel-fired RICE with natural gas-fired RICE, particularly those equipped with LEC or SCR, is also a very effective method for reducing NOx emissions by 85% to 95% and also significantly reducing if not eliminating SO_2 and PM emissions. While we did not calculate

the cost effectiveness of this control option, it is significant to note that the National Park Service has highlighted several companies that employ natural gas-fired or dual fuel drill rig engines,[527] and such engines are also being used in the Jonah Field in Wyoming.[528]

3) As a third option, existing diesel RICE can be retrofit with SCR and/or with CDPF. As demonstrated in Table 33, it is most cost effective to retrofit SCR to an existing Tier 0 or Tier 1 engine, and SCR can result in NOx emission reductions of 90% or more. And, as shown in Table 35, several California air districts have adopted NOx emission limitations that would require retrofitting of SCR to diesel RICE.
   In addition, CDPF can be retrofit to existing diesel RICE and achieve greater than 90% reduction of PM as well as reductions in VOC emissions. It must be noted that, overall, the tons of PM reduced with CDPF is an order of magnitude lower than the NOx emissions reduced with SCR, and thus the cost effectiveness of CDPF is much higher than the cost effectiveness of SCR- but that does not mean it is has not been considered a cost effective control. There are several examples of diesel particulate filter systems being retrofitted to diesel RICE.[529]

   Existing diesel-fired RICE should also be required to use ULSD fuel. EPA estimated that use of ULSD fuel would increase fuel costs by only $0.03 to $0.05 per gallon.[530] ULSD fuel is prevalent in the available fuels today and may already be required to be used in some areas/states. It is also required by the CDPF manufacturer to use ULSD fuel.

Thus, there are several options to cost effectively reduce emissions from diesel-fired engines used in the oil and gas industry. States must evaluate all available options for addressing this significant source of NOx, SO_2, PM and VOC emissions as part of their reasonable progress analysis. The most preferable options are those that address all of the visibility-impairing pollutants from this source category, with replacement of older diesel-fired engines with Tier 4 engines or replacing diesel-fired engines with natural gas-fired RICE equipped with LEC or SCR as the most effective emission limiting options.

VII. CONTROL OF NOx EMISSIONS FROM NATURAL GAS-FIRED HEATERS AND BOILERS

Natural gas-fired heaters and boilers are used in a variety of applications, including power generation and the production of process heat and steam. Boilers, reboilers, and heaters can be found throughout the production and processing segments of the oil and gas industry.

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[527] *See* August 29, 2016 Memorandum from Doug Neighbor, Superintendent, Carlsbad Caverns National Park, to Paul Murphy, Project Lead, Bureau of Land Management, Carlsbad Field Office, at 7.
[528] See Four Corners Air Quality Task Force, Report of Mitigation Options, November 1, 2007, at 62.
[529] *See* Manufacturers of Emission Controls Association, Case Study of Reciprocating Diesel Engine Retrofit Projects, November 2009, at 6-14.
[530] EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 71.

In oil and gas production and processing, heaters can be used to aid in separation (e.g., heater-treaters, gas production units (GPUs), heated flash separator units),[531] to maintain temperatures within pipes / connectors (e.g., line heaters),[532] to maintain storage tank temperatures (e.g., tank heaters), and as regenerators / reboilers (e.g., glycol dehydrators, desiccant dehydrators).[533,534] These smaller integrated units are generally rated at less than about 2.5 million Btu per hour (MMBtu/hr) heat input.[535] Larger units can be found at gas processing plants, including steam boilers, hot oil heaters, fractionation column heaters, and other process heaters that range in size from a few MMBtu/hr to 100 MMBtu/hr heat input, or more.[536]

There are two basic ways of supplying combustion air to these types of external combustion units (i.e., two draft types): (1) natural draft (i.e., atmospheric units); and (2) mechanical or forced draft. In atmospheric units, the pressure difference between the hot stack gases and the cooler ambient air creates a draft, drawing supply air into the burners. These units are open to the atmosphere (i.e., non-sealed units). Mechanical draft units use a fan to introduce combustion air into the burners. Draft type can affect the level of excess air in the combustion chamber, and the resulting emissions from the unit (e.g., NOx emissions are generally lower in mechanical draft units by operating with lower excess air and improved flame characteristics).

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[531] Heater-treaters consist of a heater, free-water knockout, and oil/condensate and gas separator. GPUs consist of a heater and a separator to remove liquid from gas prior to further processing. Heated flash separators are equipped with small boilers to facilitate condensate removal through flashing.

[532] In-line heaters are used to maintain temperatures as pressure decreases, in order to prevent formation of hydrates. Note, in-line heaters can also be used to heat gas transmission lines further downstream in the oil and gas industry.

[533] Glycol dehydrators use glycol to remove water from the gas stream in order to prevent corrosion and freezing; small reboilers are used to regenerate the glycol. Dehydrators can be located at well pads, as well as at centrally-located gathering stations and processing facilities. Solid-desiccant dehydrators are generally used for large volumes of gas, e.g., downstream of a compressor station and use a heater to regenerate the desiccant.

[534] Dehydrator use varies depending on the moisture content of the gas; dry gas requires little dehydration. For example, according to the *Four Corners Air Quality Task Force Report of Mitigations* (Oil and Gas Section), "[i]n the [coal bed methane] areas of Colorado the gas is predominantly methane and the gas is relatively dry gas and requires little dehydration . . . Conventional production in New Mexico also has very little moisture in the gas and little dehydration is required." *See* p. 90.

[535] *See* Colorado Department of Public Health and Environment, Air Pollution Control Division, Reasonable Progress Evaluation for Heater-Treater Source Category, completed for the 1st round RH plans [hereinafter referred to as "CDPHE RP for Heater-Treaters"], *available at*: https://www.colorado.gov/pacific/sites/default/files/AP_PO_Heater-Treaters_1.pdf; *also see* PA DEP PA TSD for the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A, 2700-PM-BAQ0268) and the Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5, 2700-PM-BAQ0267), FINAL June 2018. *See* p.52, *available at*: http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=8904.

[536] Hot oil heaters, or thermal fluid heaters, are used in the oil and gas industry in combination with a heat exchanger to warm up a secondary fluid (gas or liquid). This can be useful in situations with certain temperature limitations (e.g., amine used to remove H_2S can degrade at high temperatures) or to prevent corrosive fluids from degrading heating coils. Fractionation column heaters are used at natural gas processing plants to separate out natural gas liquids for further use and can be larger than 10 MMBtu/hr.

Natural gas-fired external combustion units are sources of NOx, CO, VOC, and particulate matter emissions, with NOx the primary pollutant and the focus of this section. SO_2 emissions may also occur if the field-gas used to fire the heaters contains H_2S, which converts to SO_2 during combustion. While emissions from natural gas-fired heaters (e.g., heater-treaters, line heaters, tank heaters, and reboilers) may be relatively small on a unit level, compared to other combustion sources at oil and gas production and processing sites, these units may operate continuously throughout the year. And cumulative emissions from all of the heaters in use at an oil and gas production site or processing facility can be significant.

In its initial regional haze plan, Colorado completed a Reasonable Progress Evaluation for the Heater-Treater Source Category, including a NOx emission 4-Factor analysis for reasonable progress toward the national visibility goal.[537] In its evaluation, Colorado reported that, "the multitude of gas wells in Colorado (~26,000 by 2018) result in cumulative heater-treater NOx emissions that are projected to be the largest single area source category in Colorado by 2018."[538] Colorado projected NOx emissions in 2018 would reach close to 23,000 tons per year.[539]

Federal standards, in the form of NSPS and NESHAP, exist for industrial boilers and process heaters. The NSPS for industrial-commercial-institutional steam generating units are outlined in 40 C.F.R. Part 60, Subparts Db and Dc, and apply to boilers that are capable of combusting over 10 MMBtu/hr of fuel (burning coal, oil, natural gas, or wood). Subpart Db covers industrial-commercial-institutional steam generating units with heat inputs greater than 100 MMBtu/hr and that commenced construction after September 18, 1978. Subpart Dc covers smaller industrial-commercial-institutional steam generating units that commenced constructed after June 9, 1989. These NSPS include emission standards for sulfur oxides (SOx) and PM from burning fuels other than natural gas. In addition, there are no performance testing standards for boilers burning only natural gas. EPA also regulates VOC emissions from boilers and process heaters that are used as combustion control devices under Subpart OOOO and OOOOa through VOC emission reduction requirements, operating requirements, performance testing and monitoring requirements.[540] The NESHAP for industrial boilers, commercial and institutional boilers, and process heaters is outlined in 40 C.F.R. Part 63 Subpart DDDDD and controls mercury, hydrogen chloride, particulate matter (as a surrogate for non-mercury metals), and CO (as a surrogate for organic hazardous emissions) from coal-fired, biomass-fired, and liquid-fired major source boilers based on the maximum achievable control technology. However, these requirements will not address NOx emissions. In addition, all major source boilers and process heaters are subject to a work practice standard to periodically conduct tune-ups of the boiler or process heater.

When EPA adopts or revises Federal standards for a source category, EPA is establishing an emission standard applicable to all of the source types and variable fuels, operating conditions, etc. that exist for that source category. Thus, the NSPS are generally-applicable emission standards and not a source-specific evaluation of controls. It is necessary to evaluate if more broadly applicable and more stringent requirements and pollution controls are available to achieve reasonable progress towards the national

[537] *See* CDPHE RP for Heater-Treaters.
[538] *Id.* at 1.
[539] *Id.*
[540] *See, e.g.,* 40 C.F.R. Part 60 Subpart OOOOa §§ 60.5412, 60.5412a, 60.5413a, 60.5417a.

visibility goal, especially because the NSPS and NESHAP standards have not been re-evaluated in at least 8 years. Review of state regulations, particularly to address the NAAQS which require reductions in emissions from *existing* sources, is also necessary to fully evaluate controls for emission sources associated with oil and gas development to achieve reasonable progress towards the national visibility goal.

The information provided in this section for heaters and boilers reflects a review of the available pollution controls and techniques and associated emissions levels applicable to these source categories, along with data on cost of controls where available, non-air quality environmental and energy impacts, and the useful life of the emission source being evaluated.

Uncontrolled Emission Factors from Natural Gas-Fired External Combustion Units

NOx emissions from natural gas-fired heaters and boilers are generally expressed as emission rates in pounds per million Btu heat input (lb/MMBtu) or pounds per million standard cubic feet of gas (lb/MMscf) or as a concentration in parts per million by dry volume (ppmv or ppmvd). All concentrations expressed in ppmv are on a dry basis and corrected to 3% oxygen. The following emission factors are used in this section:

EPA Emission Factor
AP-42 Natural Gas Combustion (Section 1.4, last revised 1998)
Small Boilers <100 MMBtu/hr (Uncontrolled)…….100 lb/MMscf (0.098 lb/MMBtu)
Converted to lb/MMBtu based on fuel heating value of 1,020 Btu/scf

SCAQMD Emission Factor
Units ≤2 MMBtu/hr ……110 ppmv (0.136 lb/MMBtu)
SCAQMD derived an average emission rate to calculate baseline emissions for this size category in its implementation studies for Rule 1146.2 Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters. This factor accounts for units that are considerably older and also for ones that have not had continual maintenance and upkeep.[541]

[541] *See* SJVAPCD Final Draft Staff Report with Appendices For Proposed Amendments to Rule 4308 (November 5, 2009), B-4, *available at:* http://www.valleyair.org/board_meetings/GB/agenda_minutes/Agenda/2009/November/Agenda_Item_26_Nov_5_2009.pdf [hereinafter referred to as "SJVAPCD 2009 Final Draft Staff Report for Rule 4308"].

A. COMBUSTION MODIFICATIONS

Combustion modification—such as flue gas recirculation (FGR), low-NOx burners (LNB), and ultra-low NOx burners (ULNB)—reduce NOx formation by controlling the combustion process. The following is EPA's description of these combustion control techniques:

> Staging techniques are usually used by LNB and ULNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNB's create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNB's create a lean primary combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures. The secondary combustion zone is fuel-rich. Ultra-low-NOx burners use staging techniques similar to staged-fuel LNB in addition to internal flue gas recirculation. Flue gas recirculation returns a portion of the flue gas to the combustion zone through ducting external to the firebox that reduces flame temperature and dilutes the combustion air supply with relatively inert flue gas.[542]

Retrofitting natural gas-fired heaters and boilers with LNB was identified by EPA in 1998 as one of the two most prevalent control techniques in its AP-42 Emission Factor documentation, along with FGR.[543] EPA states that, "NOx emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low NOx burners."[544] And EPA further states that, "[w]hen low NOx burners and FGR are used in combination, these techniques are capable of reducing NOx emissions by 60 to 90 percent."

CARB, in its 1991 RACT and BARCT determinations for Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, also identified LNB as one of four control methods (along with FGR, SCR, and selective noncatalytic reduction (SNCR)).[545] CARB concluded that, for units ≥5 MMBtu/hr (and ≥90,000 therms annual heat input) a BARCT NOx limit of 30 ppmv (0.036 lbs/MMBtu) could be achieved by installing new burners with FGR, noting that some units would "need to install selective noncatalytic reduction or other emission control technology instead of flue gas recirculation due to particular unit design problems."[546] However, these determinations were from 1991, and the NOx removal capabilities of low NOx burners and similar combustion controls for NOx has greatly improved over time.

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[542] EPA-453/R-93-034 Alternative Control Techniques Document—NOx Emissions from Process Heaters (Revised), September 1993, p.2-6, *available at:* https://www3.epa.gov/ttncatc1/dir1/procheat.pdf [hereinafter referred to as EPA 1993 ACT for Process Heaters].
[543] EPA, AP-42, Section 1.4.4 (last revised 1998), *available at*: https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s02.pdf.
[544] *Id.*
[545] CARB Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, July 18, 1991, p. 7 *available at:* https://ww3.arb.ca.gov/ractbarc/boilers.pdf [hereinafter referred to as "CARB 1991 Guidance"].
[546] CARB 1991 Guidance at 6.

For example, in 2018, California's SCAQMD concluded the following with regard to ULNB technology and its ability to meet very low NOx emission limits across a wide range of unit sizes:

> It was noted in the 2008 Rule 1146 and 1146.1 staff reports that there was clear evidence that these types of [ultra-low NOx] burners had been successfully retrofitted on boilers and heaters in the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) in their Rule 4306. Source tests that were conducted in conjunction with Rule 4306 showed a 98% compliance rate with a 9 ppm NOx limits using ultra-low NOx burners. In 2010, staff published a technology assessment report discussing the implementation assessment of ultra-low NOx burners subject to Rules 1146 and 1146.1. **The report concluded that the 9 ppm NOx limit can be achieved by ultra-low NOx burner systems for boilers and process heaters greater than 2 MMBtu/hour.** There were ultra-low NOx burners from 16 different manufacturers that could achieve the 9 ppm NOx compliance limit.[547]

In 2010, California's Sacramento Metropolitan AQMD (SMAQMD) determined, based on SCAQMD's rules for similar size sources and models being sold that meet SCAQMD limits, that ULNB technology was available to meet emissions limits for very small units, less than 1 MMBtu/hr.[548] Specifically, SMAQMD found that very small units less than 1 MMBtu/hr could meet a NOx limit equivalent to 20 ppmv:

> The proposed standards are technically feasible. The low NOx technology is commercially available and widely used. Additionally, these standards have already been adopted by the South Coast AQMD and the Bay Area AQMD, and except for the limits proposed for 2013 (which take effect for the SCAQMD in 2012), are already in effect in SCAQMD. As documented in the SCAQMD staff report for Rule 1146.2, as of 2006, 18% of the certification tests for units between 75,000–400,000 Btu/hr and 44% of the certification tests for units between 400,000 and 2,000,000 Btu/hr were already meeting the 14 ng/J (20 ppmv) standard. SCAQMD currently keeps a list of well over 100 certified models that are complaint with the standards in Rules 1146.2 and 1121.[549]

SMAQMD concluded that, "[t]he proposed emission limits are readily achievable through the use of low NOx burners."[550]

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[547] SCAQMD Draft Staff Report Rules 1146, 1146.1, 1146.2, and 1100, p. 2-2 [emphasis added], *available at:* http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/rule-1146-1146.1-and-1146.2/dsr-1146-final.pdf?sfvrsn=6 [hereinafter referred to as "SCAQMD 2018 Draft Staff Report"].

[548] SMAQMD Staff Report Rule 414 Water Heaters, Boilers and Process Heaters Rated Less Than 1,000,000 Btu Per Hour, January 15, 2010, p. 5, *available at:* http://www.airquality.org/ProgramCoordination/Documents/Rule414%20StaffReport%20011510.pdf [hereinafter referred to as "SMAQMD 2010 Rule 414 Staff Report"].

[549] *Id.* at 16.

[550] *Id.* at 13.

In 2015, a Ventura County Air Pollution Control District (VCAPCD) analysis for amendments to its rules for boilers, steam generators, and process heaters ≥2 and <5 MMBtu/hr found:

> Ultra-low NOx burner systems can achieve less than 9 ppm NOx for boilers, steam generators, or process heaters without the use of Flue Gas Recirculation (FGR) systems. Source tests performed by the San Joaquin Unified Air Pollution Control District showed a 95 percent compliance rate with 9 ppm limits using ultra-low NOx burners. The average NOx concentration measured was 7 ppm.[551]

And as recently as April 2019, Santa Barbara County APCD concluded the following about the ability of ULNB technology to achieve lower NOx limits of between 9 and 12 ppm for units between 2–5 MMBtu/hr:

> The focus of this rule amendment is to lower the emission limits for new and modified natural gas and field gas units from 30 ppm to the 9-12 ppm NOx emission limits, beginning on January 1, 2020. To meet these lower standards, most boilers will have to be equipped with ultra-low NOx burners. Ultra-low NOx burners are designed to achieve low emissions while maintaining good flame stability and heat transfer characteristics. Furthermore, these burners may increase thermal efficiencies by reducing the amount of excess air needed for combustion. This has the added benefit of reducing fuel usage, which results in energy savings.
>
> For most systems, a blower will be required to mix the fuel and air prior to combustion. Even atmospheric boilers, where the burners are not totally enclosed, may still need a blower to premix the fuel and air. Due to the design criteria of these atmospheric boilers, it is only feasible to have them reach the 12 ppm NOx limit, as opposed to the 9 ppm limit for non-atmospheric boilers. It is possible to reach both the 9 and 12 ppm NOx limits without the use of Flue Gas Recirculation (FGR), yet some operators may still choose to use this technology.[552]

Thus, in rulemakings enacted in California air districts from 2015 to 2019, it was essentially deemed reasonable to impose a NOx emission limit of 9 ppm for natural gas-fired heaters and boilers with heat input capacities greater than or equal to 2 ppm. However, as will be discussed in Sections B. and F., even lower NOx limits have been required for heaters and boilers in some California Air Districts.

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[551] VCAPCD Staff Report Amendments to Rule 74.15.1 Boilers, Steam Generators and Process Heaters June 23, 2015, p. 4, *available at*: http://www.vcapcd.org/pubs/Rules/74151/201506/Staff-Report-Rule-74-15-JUNE-23-%202015.pdf [hereinafter referred to as "VCAPCD 2015 Staff Report"].

[552] Santa Barbara County APCD Draft Staff Report for Amended Rule 361. Boilers, Steam Generators, and Process Heaters (Between 2–5 MMBtu/hr); Amended Rule 342. Boilers, Steam Generators, and Process Heaters (5 MMBtu/hr and greater), April 22, 2019, p. 5, *available at*: https://www.ourair.org/wp-content/uploads/2019-05cac-r361-r342-att1.pdf [hereinafter referred to as "Santa Barbara County APCD 2019 Draft Staff Report"].

There are several emerging combustion technologies that demonstrate the potential for even lower levels of NOx without the use of post-combustion controls, such as SCR:

- SOLEX™ Burner is an emerging technology designed to achieve 5 ppm NOx.[553] This burner technology is available as a burner-only alternative to SCR for units "with heat releases between 1 MMBtu/hr and +20 MMBtu/hr."[554] It can be retrofit to existing units and fits traditional ULNB footprints.

- ClearSign Ultra Low NO_x Technology is designed to achieve sub 5 ppm NOx.[555] This technology is reportedly less costly than traditional ultra-low NOx controls with no FGR, lower fuel use, and can be retrofit to existing units. This technology has been installed on several units in SJVAPCD with more testing / demonstration needed:
    - Installation at two refinery heaters (burning natural gas, not refinery gas):
        - 15 MMBtu/hr heater
        - 8 MMBtu/hr heater
    - Installation at two natural gas-fired 62.5 MMBtu/hr oil field steam generators
    - Installation at six enclosed flares (thermal oxidizers)

- Altex Technology Corporation Near Zero NOx Burner has been applied to an 8 MMBtu/hr unit and is capable of achieving 5 ppm under some operating conditions.[556] This technology is being developed as an alternative to SCR for meeting NOx limits as low as 5 ppm for smaller units (e.g., in response to SCAQMD's consideration of a 5 ppm NOx limit for units ≥2 MMBtu/hr).[557]

1. COST EFFECTIVENESS EVALUATIONS FOR COMBUSTION MODIFICATION RETROFITS, REPLACEMENTS, AND UPGRADES

California Air Districts have long been regulating NOx emissions from boilers and process heaters, with CARB issuing RACT / BARCT guidance to Air Districts in 1991.[558] In its 1991 guidance CARB determined the cost effectiveness of LNB (in 1986$) for units as small as 3.5 MMBtu/hr and as large as 150 MMBtu/hr, as follows: (1) $500–$6,400/ton for units operating at a 50% capacity factor; and (2) $300–$4,000/ton for units operating at a 90% capacity factor.[559]

More recent and more detailed cost data are available from California Air Districts that have adopted, and continue to update, regulations for these sources. Based on a review of the various California Air

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[553] John Zink Hamworthy Combustion, SOLEX™ Burner, *see:* https://www.johnzinkhamworthy.com/wp-content/uploads/solex-burner.pdf.
[554] *Id.*
[555] ClearSign https://clearsign.com/. Also see SJVAPCD presentation "ClearSign Ultra Low NOx Technology" November 7-8, 2017, *available at:* https://ww3.arb.ca.gov/enf/training/sympo/ppt2017/0830-b-scandura.pdf.
[556] California Energy Commission Report, *Near Zero NOx Burner*, July 2018, *available at:* https://ww2.energy.ca.gov/2018publications/CEC-500-2018-016/CEC-500-2018-016.pdf.
[557] *Id.*
[558] CARB 1991 Guidance.
[559] CARB 1991 Guidance Table 4. Note, CARB does not identify the underlying assumptions for annualized costs, life of controls, etc.

District rules and in researching vendor information, the source category of boilers and heaters should be subcategorized into three categories for assessing cost effectiveness and achievable NOx emission rates with combustion modifications: (1) Units > 20 MMBtu/hr (achieving NOx levels as low as 6 ppm); (2) Units >5 MMBtu/hr and ≤20 MMBtu/hr (achieving NOx levels as low as 6 ppm); and (3) Units ≤5 MMBtu/hr (achieving NOx levels of 9–20 ppm). Below, we evaluate cost effectiveness of combustion controls for each of these categories of boilers and heaters, based on cost analyses that local air agencies have relied on for regulating these units.

a) Units >20 MMBtu/hr

SJVAPCD is in the process of reviewing its rules for boilers and process heaters >5 MMBtu/hr and is proposing updates as part of its 2018 $PM_{2.5}$ Attainment Plan commitments to reduce NOx emissions.[560] SJVAPCD is considering lowering NOx limits for units >5 MMBtu/hr to levels ranging from 2–3.5 ppm.[561] As part of its control measure analysis, SJVAPCD analyzed the cost effectiveness of retrofitting units of varying sizes with ULNB to achieve a NOx level of 6 ppm, based on vendor cost data. We assume these data are in 2018$.

The SJVAPCD cost data for retrofitting existing units with ULNB includes detailed direct and indirect capital and operating costs for two unit size categories: (1) units >5 and ≤20 MMBtu/hr; and (2) units >20 MMBtu/hr.[562] For the larger size units (>20 MMBtu/hr), SJVAPCD notes that the retrofit may involve "upgrades to various systems such as fuel train to comply with up to date codes, and may involve upgrades to air intake fans, as these units require more air for the burner to operate at its optimum level."[563]

Table 36 below summarizes the total costs for retrofitting existing units >20 MMBtu/hr with ULNB, based on SJVAPCD vendor data, along with calculated annualized costs of the control, assuming a 5.5% interest rate and a 25-year life. Low NOx technologies should last the life of the emission unit. SCAQMD is currently assuming a 25-year life for refinery heaters and boilers.[564] And a review of the emission units in New Mexico permitted oil and gas sources such as gas processing plants show average ages of boilers and heaters of 30-35 years. Thus, we used a 25-year life as a minimum life for a heater or boiler controls in the cost effectiveness analysis, which seems more than justified. Table 36 presents the cost effectiveness of applying these low NOx technologies to existing units to reduce NOx emissions from uncontrolled levels to 6 ppm. Uncontrolled emissions are based on the EPA AP-42 uncontrolled

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[560] SJVAPCD Rules 4306 and 4320. *See*: https://www.valleyair.org/Workshops/public_workshops_idx.htm#12-05-19_ICE.

[561] SJVAPCD 2018 Plan for the 1997, 2006, and 2012 $PM_{2.5}$ Standards (November 15, 2018), Appendix C: Stationary Source Control Measure Analysis at C-94, *available at:* http://www.valleyair.org/pmplans/documents/2018/pm-plan-adopted/C.pdf [hereinafter referred to as "SJVAPCD 2018 $PM_{2.5}$ Attainment Plan"].

[562] SJVAPCD 2018 $PM_{2.5}$ Attainment Plan pp. C-80–C-82. Note, the cost estimates assume that the existing foundation and supports will not be replaced and that direct and indirect annual costs are presumed to be the same as the existing burner.

[563] SJVAPCD 2018 $PM_{2.5}$ Attainment Plan at C-81.

[564] *See, e.g.,* SCAQMD Presentation for Rule 1109.1 – NO_x Emission Reduction for Refinery Equipment, Working Group Meeting #9, December 12, 2019, slides 41 and 57, *available at:* http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pr1109-1-wgm_9_final.pdf?sfvrsn=12.

emission rate for small boilers <100 MMBtu/hr of 100 lb/MMscf (0.098 lb/MMBtu). Meeting an emission limit of 6 ppm from this uncontrolled level reflects a control efficiency using state-of-the-art ultra-low NOx burner technology of 93%. Cost effectiveness is presented for operation at a 50% and 90% capacity factor.

Table 36. Cost Effectiveness of Retrofitting Existing Units with ULNB to Achieve a NOx Level of 6 ppm at Boilers and Heaters >20 MMBtu/hr Operating at a 50% and 90% Capacity Factor.[565]

UNIT SIZE (MMBtu/hr)	TOTAL CAPITAL COSTS (2018$)	TOTAL ANNUALIZED COSTS (2018$)	COST EFFECTIVENESS ($/TON) 50% CAPACITY FACTOR	COST EFFECTIVENESS ($/TON) 90% CAPACITY FACTOR
30	$261,813	$19,518	$3,270	$1,817
40			$2,452	$1,362
50			$1,962	$1,090
60			$1,635	$908
70			$1,401	$779
80			$1,226	$681
90			$1,090	$606
100			$981	$545

Based on this analysis of SJVAPCD cost data, it can be cost effective to apply ULNB to existing units >20 MMBtu/hr to reduce NOx emissions to a level of 6 ppm.

SJVAPCD provides separate cost data for oilfield steam generators, noting that most of these units would be 62.5 MMBtu/hr.[566] The SJVAPCD analysis notes that, "[a]s many steam generators are one off built units, they may have different firebox configurations that may not accept the new burner without varying degrees of modification."[567] However, SJVAPCD analyzed retrofitting these units with new burner technology to achieve a NOx level as low as 5 ppm, based on vendor data. Using this same vendor cost data, the cost effectiveness of retrofitting a 62.5 MMBtu/hr unit to reduce NOx levels to 5 ppm ranges from $1,664/ton to $6,656/ton, depending on the extent of the modifications or upgrades that are needed.[568]

[565] Cost data provided by vendors to SJVAPCD, annualized costs calculated assuming a 25-year life and a 5.5% interest rate.
[566] SJVAPCD 2018 $PM_{2.5}$ Attainment Plan at C-83.
[567] *Id.*
[568] This range of cost effectiveness is based on retrofit cost data of $450,000–$1,800,000 and assumes an 80% capacity factor from SJVAPCD's analysis. Annualized costs are calculated assuming a 25-year life and a 5.5% interest rate.

b) Units >5 and ≤20 MMBtu/hr

We also completed a cost effectiveness analysis of retrofitting existing units >5 and ≤20 MMBtu/hr with ULNB based on SJVAPCD vendor cost data for units of this size.[569] Table 37 presents the cost effectiveness of retrofitting existing units >5 and ≤20 MMBtu/hr with ULNB to reduce NOx emissions to 6 ppm from uncontrolled levels based on the EPA AP-42 uncontrolled emission rate for small boilers <100 MMBtu/hr of 100 lb/MMscf (0.098 lb/MMBtu). Meeting an emission limit of 6 ppm from this uncontrolled level reflects a control efficiency using state-of-the-art ultra-low NOx burner technology of 93%. Cost effectiveness is presented for operation at a 50% and 90% capacity factor.

Table 37. Cost Effectiveness of Retrofitting Existing Units with ULNB to Achieve a NOx Level of 6 ppm at Boilers and Heaters >5 and ≤20 MMBtu/hr Operating at a 50% and 90% Capacity Factor.[570]

UNIT SIZE (MMBtu/hr)	TOTAL CAPITAL COSTS (2018$)	TOTAL ANNUALIZED COSTS (2018$)	COST EFFECTIVENESS ($/TON) 50% CAPACITY FACTOR	COST EFFECTIVENESS ($/TON) 90% CAPACITY FACTOR
5	$69,816	$5,205	$5,232	$2,906
10			$2,616	$1,453
15			$1,744	$969
20			$1,308	$727

Based on this analysis using SJVAPCD cost data, it can be cost effective to apply ULNB to existing units >5 and ≤20 MMBtu/hr to reduce NOx emissions to a level of 6 ppm.

c) Units ≤5 MMBtu/hr

SMAQMD, in a cost effectiveness analysis for its most recent revision of its rules (in 2005) for boilers and heaters ≥1 MMBtu/hr, noted that, for units ≥1 MMBtu/hr and <5 MMBtu/hr, "[s]ome of these units may not be retrofitted because of equipment age and design and will have to be replaced with new units."[571]

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[569] SJVAPCD 2018 $PM_{2.5}$ Attainment Plan pp. C-81–C-82. Note, the cost estimates assume that the existing foundation and supports will not be replaced and that direct and indirect annual costs are presumed to be the same as the existing burner.

[570] Cost data provided by vendors to SJVAPCD, annualized costs calculated assuming a 25-year life and a 5.5% interest rate.

[571] Sacramento Metropolitan AQMD Staff Report Rules 411 and 301, October 27, 2005, p. 10, *available at:* http://www.airquality.org/ProgramCoordination/Documents/Rules411and301%20StaffReport%20102705%20Item11.pdf [hereinafter referred to as "SMAQMD 2005 Rule 411 Staff Report"].

The SMAQMD cost data included the costs for replacing existing units with new units equipped with "low NOx technologies" in order to meet the District's emission limits, including costs for equipment, installation, permitting, and source testing for unit sizes ranging from 1–100 MMBtu/hr.[572] Operating and maintenance costs of a new low-NOx unit are assumed to be the same as older units. Thus, it is assumed that it is more cost effective to replace units that are of a size less than or equal to 5 MMBtu/hr with new units equipped with state-of-the-art combustion controls for NOx.

Table 38 below summarizes cost data for replacing units ≤5 MMBtu/hr with new units with "low NOx technologies." The costs include costs for equipment, installation, permitting, and source testing, along with calculated annualized costs of the control, and assume a 5.5% interest rate and a 30-year life of the new unit.[573] These low NOx technologies should last the life of the emission unit, and Colorado assumed a 30–40 year life for heater-treater units of this size based on manufacturer data.[574] We used a 30-year life as a minimum useful life for replacement heater or boiler controls in the cost effectiveness analysis, which is justified.

Table 38. Total and Annualized Costs of Replacement of Boilers and Heaters ≤5 MMBtu/hr with New Units with Low NOx Technologies.[575]

UNIT SIZE (MMBtu/hr)	TOTAL CAPITAL COSTS (2005$)	TOTAL ANNUALIZED COSTS (2005$)
1	$36,284	$2,551
2	$52,284	$3,652
3	$72,284	$5,028
4	$80,284	$5,579
5	$135,567	$9,328

For the units of 5 MMBtu/hr and lower, SMAQMD's Rule 411 establishes a NOx limit of 30 ppm, but there have been improvements in low NOx technologies demonstrating that units in this size range can meet NOx limits of 20 ppm and even as low as 9 ppm for some applications, based on a review of vendor information.[576] Several California Air Districts require units >2 and <5 to meet a limit of 7–12 MMBtu/hr and units ≤2 MMBtu/hr to meet a limit of 20 ppm. For example, SCAQMD Rule 1146.1 requires units >2 and <5 MMBtu/hr meet limits between 7–12 ppm, depending on the type of unit. And SJVAPCD Rule 4307 requires units >2 and ≤5 MMBtu/hr meet limits of 9 ppm (non-atmospheric units) and 12 ppm

[572] SMAQMD 2005 Rule 411 Staff Report Attachment D-1.
[573] SMAQMD 2005 Rule 411 Staff Report Attachment D-2.
[574] CDPHE RP for Heater-Treaters at 5.
[575] Cost data provided by boiler manufacturers to SMAQMD, annualized costs calculated assuming a 30-year life and a 5.5% interest rate.
[576] *See, e.g.,* Parker Industrial Boiler, offering units <5 MMBtu/hr with Low NOx Power Burners for NOx levels to 9 ppm. *Available at*: https://www.parkerboiler.com/products/.

(atmospheric units). SCAQMD Rule 1146.2 requires units ≤2 MMBtu/hr be manufactured to meet a NOx limit of 20 ppm and SCAQMD provides a list of numerous units that are pre-certified to meet this limit.[577] SJVAPCD also requires point-of-sale NOx limits for units ≤2 MMBtu/hr of 20 ppm.[578] And VCAPCD's Rule 74.15.1 currently requires new and replacement units ≥1 and ≤2 MMBtu/hr to also meet a 20 ppm NOx limit.[579] See Table 42 for a complete and more detailed list of state and local rules, including many with limits for units in this size range of 9–20 ppm.

While the costs of NOx combustion control technologies to meet NOx limits as low as 9 ppm may be higher than what SMAQMD assumed in its 2005 cost analysis, it is also likely that the costs of low NOx combustion controls have not changed much since then. This is because as air pollution controls are required to be implemented more frequently over time, the cost of the air pollution control often decreases due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc. For example, SCAQMD concluded from its 2008 cost analysis that, "[t]he capital cost for retrofitting a unit has decreased by about 70%...."[580]

Therefore, we calculated the cost effectiveness of retrofitting these size units with low NOx technologies using these cost data based on two emission control scenarios: (1) meeting the SMAQMD limit of 30 ppm; and (2) meeting limits achievable today with low NOx combustion technology.

Table 39 below summarizes the cost effectiveness of replacing existing units ≤5 MMBtu/hr with new units with low NOx technologies, based on SMAQMD cost data shown above in Table 38. Table 39 below presents the cost effectiveness of replacement units with low NOx technologies to reduce NOx emissions from the uncontrolled emission rate based on EPA for units >2 MMBtu/hr and the SCAQMD-derived average unit emission rate of 110 ppmv (0.136 lb/MMBtu/hr) for units ≤2 MMBtu/hr. The SCAQMD-average unit emission rate was, "derived by the SCAQMD to calculate the baseline emissions for this [size] category."[581] This rate, "accounts for units that are considerably older and also for ones that have not had continual maintenance and upkeep."[582] Operating and maintenance costs of a new low-NOx unit are assumed to be the same as older units. For the second scenario, the analysis assumes units >2 and ≤5 MMBtu/hr meet a NOx limit of 9 ppm and units ≤2 MMBtu/hr meet a NOx limit of 20 ppm. Meeting emission limits of 9 ppm and 20 ppm from the estimated uncontrolled levels reflect a control efficiency of 89% and 82%, respectively. Cost effectiveness is presented for operation at a 50% and 90% capacity factor.

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[577] *See* http://www.riteboiler.com/docs/Rite-Low-NOx-SCAQMD-Precertified-Boilers.pdf.
[578] SJVAPCD Rule 4308. *Available at:* https://www.valleyair.org/rules/currntrules/03-4308_CleanRule.pdf.
[579] VCAPCD Rule 74.15.1. *Available at:* http://www.vcapcd.org/Rulebook/Reg4/RULE%2074.15.1.pdf.
[580] SCAQMD 2018 Draft Staff Report at 4-3. Note, while SCAQMD's analysis specifically applies to retrofitting units ≥20 and <75 MMBtu/hr with ULNB it's also possible that these changes in cost would apply to units of other sizes, as well.
[581] SJVAPCD 2009 Final Draft Staff Report for Rule 4308.
[582] *Id.*

Table 39. Cost Effectiveness of Replacing Existing Boilers and Heaters ≤5 MMBtu/hr with New Units with Low NOx Technologies Operating at a 50% and 90% Capacity Factor.[583]

UNIT SIZE (MMBtu/hr)	COST EFFECTIVENESS ($/TON) 50% CAPACITY FACTOR NOx RATE: 30 ppm	COST EFFECTIVENESS ($/TON) 90% CAPACITY FACTOR NOx RATE: 30 ppm	COST EFFECTIVENESS ($/TON) 50% CAPACITY FACTOR NOx RATES: 20 ppm (≤2 MMBtu/hr) 9 ppm (>2 MMBtu/hr)	COST EFFECTIVENESS ($/TON) 90% CAPACITY FACTOR NOx RATES: 20 ppm (≤2 MMBtu/hr) 9 ppm (>2 MMBtu/hr)
1	$12,160	$6,756	$10,809	$6,005
2	$8,703	$4,835	$7,736	$4,298
3	$12,322	$6,846	$8,771	$4,873
4	$10,254	$5,696	$7,298	$4,055
5	$13,715	$7,619	$9,762	$5,423

For the smallest units, San Joaquin Valley APCD (SJVAPCD) analyzed the cost of reducing NOx emissions for its point-of-sale rule for boilers and process heaters sized 0.075 to less than 2 MMBtu/hr. Table 40 below shows the differential capital costs (i.e., the difference in cost between a compliant and non-compliant unit), the annualized costs re-calculated using on a 5.5% interest rate (in place of the 10% interest rate assumed by SJVAPCD), and the cost of NOx reduction based on a current unit average emission rate of 110 ppmv meeting a limit of 20 ppmv. For units ≤2 MMBtu/hr uncontrolled emissions are estimated based on the SCAQMD-derived average unit emission rate of 110 ppmv (0.136 lb/MMBtu/hr). Operating and maintenance costs of a new low-NOx unit are assumed to be the same as older units. Cost data were provided to SJVAPCD by stakeholders, retailers, and manufacturers. And again, we used a 30-year life as a minimum life for replacing unit controls with low NOx technologies in the cost effectiveness analysis, as previously discussed. SJVAPCD used a 22% capacity factor in its analysis based on survey data collected by SCAQMD and Bay Area AQMD for "typical usages for these units," which presumably reflect a wide range of application and do not necessarily reflect how these size units are used in oil and gas applications, where heaters can operate continuously.

[583] Cost data provided by boiler manufacturers to SMAQMD (2005$), annualized costs calculated assuming a 30-year life and a 5.5% interest rate.

Table 40. Cost Effectiveness Based on Differential Costs to Reduce NOx Emissions from Replacing Units with Units with Low-NOx Burner Technology to Meet a NOx Limit of 20 ppm, Operating at 22% Capacity[584]

UNIT SIZE (MMBtu/hr)	DIFFERENTIAL CAPITAL COST (2009$)	ANNUALIZED COST (2009$)	COST EFFECTIVENESS (2009$)
0.75	$100	$8	$883/ton
0.4	$750	$63	$1,242/ton
2.0	$3,000	$251	$994/ton

For units operating at a higher capacity factor, as would likely be the case for many of the units used in the oil and gas production and processing segments, the cost per ton of NOx removal of choosing to replace a unit with a new unit with low NOx technologies over a higher-emitting unit would be even less than what is shown in Table 40. For these type of smaller units, SCAQMD Rule 1146.2 requires units with rated capacities between 400,000 and 2,000,000 Btu/hr (i.e., 0.04 and 2 MMBtu/hr) and more than 15 years old, depending on the original manufacturer date, to meet the same emission standards as new units.[585] Meeting these standards, according to SCAQMD, requires the retrofit, or more likely, replacement of the older units.[586]

In its initial regional haze plan, Colorado completed a Reasonable Progress Evaluation for the heater-treater source category, including a NOx emission 4-Factor analysis for reasonable progress toward the national visibility goal.[587] In its evaluation, Colorado reported that:

> The Four Corners Air Quality Task Force considered low NOx burners as a mitigation option for the Four Corners area and had the following finding: "Application not appropriate for the San Juan Basin, because most burners commonly used in the Four Corners Area are smaller than the technology is capable of providing emission reduction." It appears likely that this technology would also be technically infeasible for the Denver-Julesburg (DJ) Basin considering that low-NO_X burners are not commercially available for very small combustion sources such as heater-treaters.[588]

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[584] *See* SJVAPCD 2009 Final Draft Staff Report for Rule 4308. Annualized costs of control were calculated using a capital recovery factor of 0.068805 (assuming a 30-year life of controls and a 5.5% interest rate). NOx emission reductions are based on SJAPCD's assumed unit average emission rate of 110 ppmv meeting an emission limit of 20 ppmv.
[585] SCAQMD Rule 1146.2, *available at:* http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1146-2.pdf?sfvrsn=17.
[586] *See* SMAQMD 2010 Rule 414 Staff Report at 13 (describing SCAQMD rules).
[587] CDPHE RP for Heater-Treaters.
[588] *Id.* at 3.

The Four Corners Air Quality Task Force report was from 2007 and there have been great improvements since then in low NOx technologies. As shown throughout this section on combustion modifications, however, units around 2 MMBtu/hr, and even smaller, are available with low NOx technologies that can meet very low NOx emission limits and can even, in some cases, be retrofitted with these technologies to achieve emissions reductions from existing units. Note, Colorado's RP for Heater-Treaters indicates that a typical heater-treater design rate is about half of the 5 MMBtu/hr threshold for exemptions from Colorado's permitting requirements.[589] And beyond these very small units, low NOx technologies are widely available and generally cost effective for units ≥5 MMBtu/hr.

2. LOWERING COMBUSTION TEMPERATURES TO REDUCE NOx EMISSIONS

Colorado also considered lowering heater-treater temperatures to reduce NOx emissions and described this combustion modification approach, as follows:

> This technology (lowering the heater-treater temperature) was identified by EPA Natural GasSTAR in PRO Fact Sheet No. 906. The fact sheet was written with reduction of methane in mind, although this technology would also reduce combustion emissions because it would reduce fuel use. The following is from the fact sheet: "...heater-treater temperatures at remote sites may be higher than necessary, resulting in increased methane emissions. Commonly, the reason for this is that operators need to reduce the chance of having a high water content in the produced oil and manpower limitations do not allow for constant monitoring at remote sites. Field personnel, consequently, are inclined to operate the equipment at levels that cause the least problems, but also result in higher than necessary emissions."[590]

Estimates for NOx emission reductions from lowering heater-treater temperatures were not provided in EPA's Gas STAR analysis and were not assessed by Colorado. Capital costs were estimated at $1,000–$10,000 and annual operating and maintenance costs were estimated to range from $100–$1,000.[591] Colorado anticipated that there would be no additional time needed for achieving compliance with this technology, that the lowered heater-treater temperature would reduce fuel use, and that there would be no non-air quality impacts. Further, Colorado concluded that this control technology would not affect the service life of the heater-treater, noting that the typical life of a heater-treater is 30 to 40 years.[592]

There are few energy and non-air environmental impacts of combustion modifications for heaters and boilers. Generally, the combustion practices used to reduce NOx emissions also increase thermal efficiencies by reducing the amount of excess air needed for combustion, which has the added benefit

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[589] *Id.* at 5.
[590] *Id.* at 2.
[591] *See* EPA Partner Reported Opportunities (PRO) Fact Sheet No. 906 (last updated September 2004), *available at:* https://www.globalmethane.org/documents/m2mtool/docs/lowerheatertreatertemp.pdf and CDPHE RP for Heater-Treaters at 3.
[592] CDPHE RP for Heater-Treaters at 4.

of reducing fuel usage and increasing energy savings. According to EPA, "[r]eductions in NOx formation achieved by reducing flame temperature and oxygen levels can increase CO and HC emissions if NOx reductions by combustion controls are taken to extremes."[593] And systems where blowers or fans are used, e.g., for LNB plus FGR, will require additional electric energy.

According to EPA, the length of time to install ULNB is 6–8 months (excluding permitting, reporting preparation, and programmatic and administrative considerations).[594]

While the cost estimates in this section on combustion modification are of a cost basis that spans a timeframe from 1986–2018, it is important to note that, beginning in 2006, several state and local air agencies adopted rules to lower NOx emission limits of 30 ppmv to as low as 5–12 ppm for larger units and found it was cost effective to require such a level of control on existing boilers and heating units. This will be discussed further in Section F. below. It is not possible to accurately escalate the older costs to more current dollars. EPA cautions against escalating costs over a period longer than five years because it can lead to inaccuracies in price estimation.[595] Further, the prices of an air pollution control do not always rise at the same level as price inflation rates. In some cases, the cost of the air pollution control decreases over time due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc.[596] In any event, the fact that air agencies have found low NOx combustion technologies to be cost effective to meet NOx emission limits in the range of 5 to 30 ppm indicates that similar sources have had to incur the costs reflected in Tables 36-40 to meet reduced NOx emission limits, and thus the costs of low NOx combustion technology should be considered reasonable for most heaters and boilers.

B. POST-COMBUSTION CONTROLS: SCR AND SNCR

Post-combustion controls, such as SCR and SNCR, reduce NOx formation in the flue gas. The following is EPA's description of these add-on control techniques:

> These techniques control NOx by using a reactant that reduces NOx to nitrogen (N2) and water. The reactant, ammonia (NH3) or urea for SNCR, and NH3 for SCR, is injected into the flue gas stream. Temperature and residence time are the primary factors that influence the reduction reaction. Selective catalytic reduction uses a catalyst to facilitate the reaction.[597]

[593] EPA 1993 ACT for Process Heaters Section 2.4.
[594] 2016 EPA CSAPR TSD for Non-EGU Emissions Controls at 15.
[595] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.
[596] For example, SCAQMD concluded from its 2008 cost analysis that, "[t]he capital cost for retrofitting a unit has decreased by about 70%...." (SCAQMD 2018 Draft Staff Report at 4-3).
[597] EPA 1993 ACT for Process Heaters at 2-6.

SCR systems on natural gas-fired boilers and heaters should be able to achieve NOx removal efficiencies in the range of 80 to 90+%.[598] SNCR systems on natural gas-fired industrial boilers and heaters can achieve NOx reductions in the range of 30-75%.[599]

As early as 1991, CARB, in its 1991 RACT / BARCT determination for Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, identified SCR and SNCR as two of four control methods (along with FGR and LNB).[600] CARB concluded that, for units ≥5 MMBtu/hr (and ≥90,000 therms annual heat input), a BARCT NOx limit of 30 ppmv (0.036 lbs/MMBtu) could be achieved by installing new burners with FGR, noting that some units would "need to install selective noncatalytic reduction or other emission control technology instead of flue gas recirculation due to particular unit design problems."[601]

EPA provided cost effectiveness data for SNCR at model heaters in its 1993 Alternative Control Techniques document. Specifically, cost effectiveness of SNCR for heaters, at the time, ranged from: (1) $3,200–$6,700/ton for a 77 MMBtu/hr heater; (2) $2,700–$5,700/ton for a 121 MMBtu/hr heater; and (3) $2,300–$4,900/ton for 186 MMBtu/hr heater.[602]

California Air Districts have long been regulating NOx emissions from boilers and process heaters, with CARB issuing RACT / BARCT guidance to Air Districts in 1991.[603] In its 1991 guidance, CARB determined the cost effectiveness of SNCR (in 1986$) for units as small as 50 MMBtu/hr and as large as 375 MMBtu/hr, as follows: (1) $1,500–$6,000/ton for units operating at a 50% capacity factor; and (2) $1,300–$3,800/ton for units operating at a 90% capacity factor.[604]

More recent and more detailed cost data are available from California Air Districts that have adopted, and continue to update, regulations for these sources. A recent analysis by California's SCAQMD for revisions to its series of rules for boilers and process heaters (i.e., Rules 1146, 1146.1, and 1146.2) concluded that, "[u]pon reviewing the type of pollution control technologies available to control NOx emissions applicable to the boilers, steam generators and process heaters subject to Rule 1146 and 1146.1, SCR and ultra-low NOx burners are still the main technologies that can achieve the NOx concentration limits specified in these rules."[605] SCAQMD further determined that, "[b]ased on the 2008 staff reports for Rule 1146 and 1146.1, SCR as applied to Rule 1146 boilers can achieve NOx

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[598] *See* Petroleum Refinery Tier 2 BACT Analysis Report, Prepared for EPA by Eastern Research Group, Inc., January 16, 2001, at 3-11, available at: https://archive.epa.gov/airquality/ttnnsr01/web/pdf/bactrpt.pdf. *See* also NESCAUM 2000 Status Report at II-7. These are both cited by EPA in its Chapter 2, Selective Catalytic Reduction, June 2019, in Section 4 of EPA's Control Cost Manual (References 19 and 24)

[599] *See* EPA, Control Cost Manual, Section 4, Chapter 1, Selective Noncatalytic Reduction, at 1-2, *available at:* https://www.epa.gov/sites/production/files/2017-12/documents/sncrcostmanualchapter7thedition20162017revisions.pdf.

[600] CARB 1991 Guidance at 8.

[601] CARB 1991 Guidance at 6.

[602] EPA 1993 ACT for Process Heaters Table 2-4. EPA calculates an annualized cost of control assuming a capital recovery factor of 0.131474 (i.e., assuming a 15-year life of controls and a 10% interest rate).

[603] CARB 1991 Guidance.

[604] CARB 1991 Guidance Table 4. Note, CARB does not identify the underlying assumptions for annualized costs, life of controls, etc.

[605] SCAQMD 2018 Draft Staff Report at 2-4.

concentrations from 5 to 6 ppm for units greater than or equal to 75 MMBtu/hr."[606] SCAQMD's revisions to Rule 1146 for Boilers, steam generators, and process heaters ≥5 MMBtu/hr allow facilities until January 1, 2022 to retrofit all existing units and until January 1, 2023 to replace any existing units to meet a NOx emission limit of 5 ppm for units ≥75 MMBtu/hr burning natural gas.[607] SCAQMD determined that the 1146 rule series are cost effective, including for units ≥75 MMBtu/hr retrofitted with SCR to meet an emission limit of 5 ppm.[608]

In the SJVAPCD, the District described the following approach to achieving lower NOx limits, acknowledging certain technical and cost feasibility considerations with SCR for certain units:

> The amendment of Rule 4306 in October 2008 was initially proposed to lower the NOx emission limit from 9 ppmv to 6 ppmv for units greater than 20 MMBtu/hr. It was determined that the proposed NOx limits could be accomplished by using selective catalytic reduction (SCR) or a combination of SCR and ultra-low NOx burners (ULNBs), thus making the lower limits technologically feasible. However, through the public workshop process and additional research it was also determined that most of the units subject to Rule 4306 have undergone several generations of NOx controls, and consequently, certain applications of SCR may not be cost effective and/or technological infeasible because of physical limitations. Therefore, the lower NOx limits were included in new Rule 4320 and an option was provided in the rule that allows for the payment of an annual emissions fee based on total actual emissions, rather than installation of additional NOx controls. These fees are used by the District to achieve cost effective NOx reductions through District incentive programs, the District's Technology Advancement Program, and other routes.[609]

SJVAPCD is in the process of reviewing its rules for boilers and process heaters >5 MMBtu/hr and is proposing updates as part of its 2018 $PM_{2.5}$ Attainment Plan commitments to reduce NOx emissions.[610] SJVAPCD is considering lowering NOx limits for units >5 MMBtu/hr to levels ranging from 2–3.5 ppm.[611] As part of its control measure analysis, SJVAPCD analyzed the cost effectiveness of retrofitting units of varying sizes with SCR to achieve these NOx levels, based on information from SCR vendors. We assume these data are in 2018$.

The SJVAPCD cost data for retrofitting existing units with SCR includes detailed direct and indirect capital, installation, and operating and maintenance costs for two unit size categories: (1) units >5 and ≤20 MMBtu/hr; and (2) units >20 MMBtu/hr.[612]

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[606] *Id.* at 2-2.
[607] *Id.* at 1-2.
[608] *Id.* at 4-6.
[609] *See* SJVAPCD 2016 Plan for the 2008 8-Hour Ozone Standard (June 16, 2016), p. C-27, *available at:* http://www.valleyair.org/Air_Quality_Plans/Ozone-Plan-2016/c.pdf.
[610] SJVAPCD Rules 4306 and 4320. *See*: https://www.valleyair.org/Workshops/public_workshops_idx.htm#12-05-19_ICE.
[611] SJVAPCD 2018 $PM_{2.5}$ Attainment Plan pp. C-84–C-87.
[612] SJVAPCD 2018 $PM_{2.5}$ Attainment Plan pp. C-80–C-82. Note, the cost estimates assume that the existing foundation and supports will not be replaced and that direct and indirect annual costs are presumed to be the same as the existing burner.

Table 41 below summarizes the total costs for retrofitting existing units ≥5 MMBtu/hr with SCR, based on SJCAPCD-obtained vendor data, along with calculated annualized costs of the control, assuming a 5.5% interest rate and a 25-year life for SCR. SCAQMD is currently assuming a 25-year life for refinery heaters and boilers.[613] Table 41 also presents the cost effectiveness of applying SCR existing units to reduce NOx emissions from uncontrolled levels to levels of: (1) 2.5 ppm for units >20 MMBtu/hr; and (2) 3.5 ppm for units >5 and ≤20 MMBtu/hr.[614] Uncontrolled emissions are based on the EPA AP-42 uncontrolled emission rate for small boilers <100 MMBtu/hr of 100 lb/MMscf (0.098 lb/MMBtu). Meeting emission limits of 2.5 ppm and 3.5 ppm from this uncontrolled level reflects a control efficiency using state-of-the-art SCR technology of 96% and 97%, respectively. Cost effectiveness is presented for operation at a 50% and 90% capacity factor.

Table 41. Cost Effectiveness of Retrofitting Existing Units with SCR to Achieve NOx Levels of 2.5 ppm for Units >20 MMBtu/hr and 3.5 ppm for Units >5 and ≤20 MMBtu/hr Operating at a 50% and 90% Capacity Factor.[615]

UNIT SIZE (MMBtu/hr)	TOTAL CAPITAL COSTS (2018$)	TOTAL ANNUALIZED COSTS (2018$)	COST EFFECTIVENESS ($/TON) 50% CAPACITY FACTOR	COST EFFECTIVENESS ($/TON) 90% CAPACITY FACTOR
5	$261,728	$26,055	$25,354	$14,086
10			$12,677	$7,043
15			$8,451	$4,695
20			$6,339	$3,521
30	$385,705	$38,397	$6,149	$3,416
40			$4,612	$2,562
50			$3,689	$2,050
60			$3,074	$1,708
70			$2,635	$1,464
80			$2,306	$1,281
90			$2,050	$1,139
100			$1,845	$1,025

[613] *See, e.g.,* SCAQMD Presentation for Rule 1109.1 – NO_x Emission Reduction for Refinery Equipment, Working Group Meeting #9, December 12, 2019, slides 41 and 57, *available at:* http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pr1109-1-wgm_9_final.pdf?sfvrsn=12.

[614] *See* SJVAPCD 2018 $PM_{2.5}$ Attainment Plan at C-85 and C-87, stating: "Source test results of various units with SCR systems indicate that an SCR can potentially achieve 3.5 ppmv NOx @ 3% O2 for units rated between 5 to 20 MMBtu/hr." and "Source test results of various units with SCR system indicate that an SCR can reliably achieve 2.5 ppmv NOx @ 3% O2 (or less) emissions for units greater than 20 MMBtu/hr."

[615] Cost data provided by vendors to SJVAPCD, annualized costs calculated assuming a 25-year life and a 5.5% interest rate.

SJVAPCD based its cost analysis on vendor data for the SCR systems and largely on EPA's Air Pollution Control Cost Manual (6th Edition) for installation, operating and maintenance costs, etc., for these systems.

This analysis indicates that it is cost effective to retrofit units, especially those >20 MMBtu/hr, with SCR to achieve NOx levels as low as 2.5–3.5 ppm.

The energy and non-air environmental impacts of post-combustion control techniques include:

- Parasitic load of operating an SCR system, which requires additional energy (fuel use and electricity) in order to maintain output across the catalyst;
- Solid waste disposal of spent SCR catalyst;
- Ammonia, CO, and nitrous oxide emissions with the use of SNCR;
- Ammonia and sulfite emissions with the use of SCR; and
- Ammonia handling and storage with SNCR and SCR.[616]

According to EPA, the length of time to install SCR is 28–58 weeks (excluding permitting, reporting preparation, and programmatic and administrative considerations).[617] The Institute of Clean Air Companies has stated that SCRs for smaller units (less than 20,000 standard cubic feet per minute gas throughput) are often available in ready-to-install SCR skid packages, and thus SCR for smaller units would take closer to 28 weeks to install.[618] An SNCR would take much less time to install. The Institute of Clean Air Companies states that it takes about 10-13 months to install SNCR, which covers the time from bid evaluations to startup of the SNCR.[619]

C. NOx CONTROLS FOR SEPARATORS

Colorado's Reasonable Progress Evaluation for the heater-treater source category evaluated the installation of insulation on the separator to reduce fuel usage, and resulting combustion emissions (including NOx).[620] Installation of insulation on separators was also included in the Four Corners Air Quality Task Force Report of Mitigation Options for the oil and gas industry and determined to be a technically feasible technique for reducing NOx emissions.[621] Estimates for NOx emission reductions from insulating separators were not provided in the Four Corners Air Quality Task Force report and were not assessed by Colorado. The cost effectiveness of this control will depend on the remaining life of the

[616] EPA 1993 ACT for Process Heaters Section 2.4.
[617] 2016 EPA CSAPR TSD for Non-EGU Emissions Controls at 15.
[618] *See* Institute of Clean Air Companies, Typical Installation Timelines for NOx Emissions Control Technologies on Industrial Sources, December 4, 2006, at 4-5, *available at:* https://cdn.ymaws.com/icac.site-ym.com/resource/resmgr/ICAC_NOx_Control_Installatio.pdf.
[619] *Id.* at 7-8.
[620] CDPHE RP for Heater-Treaters.
[621] Four Corners Air Quality Task Force Report of Mitigation Options (November 1, 2007) at 89.

equipment to which it is applied. Colorado anticipated that there would be no additional time needed for achieving compliance with this technology and that there would be no non-air quality impacts.

D. NOx CONTROLS FOR DEHYDRATORS

Use of a zero emission dehydrator can significantly reduce fuel requirements for a reboiler and therefore reduce combustion emissions (including NOx). The Four Corners Air Quality Task Force report identified this type of dehydrator as a mitigation option and described this type of unit and its emissions, as follows:

> The zero emissions dehydrator combines several technologies that lower emissions. These technologies eliminate emissions from glycol circulation pumps, gas strippers and the majority of the still column effluent. . . . Benefits of this technology include: . . . Reduces emissions of particulate matter, sulfur dioxide, NOx or CO emissions . . . Significantly reduces fuel requirements for glycol reboiler. Natural gas that was used for this purpose can now be sent to market.[622]

The Four Corners Air Quality Task Force report describes how existing dehydrators can be retrofitted to zero emissions dehydrators, "by modifying the gas stream piping and using a 5 kW engine-generator for electricity needs."[623] The Four Corners Air Quality Task Force reports that operating and maintenance costs are lower than for conventional glycol dehydrators and further reports that EPA estimates the payback for installing a zero emission dehydrator in place of a conventional glycol dehydrator to occur in less than a year.[624]

E. CENTRAL GATHERING FACILITIES TO REDUCE NOx EMISSIONS FROM WELLHEAD SEPARATION SOURCES

Centralization of gas well gathering facilities can be employed to reduce and consolidate wellsite sources, including heaters and separators. Colorado's Reasonable Progress Evaluation for the heater-treater source category evaluated central gathering facilities to remove wellhead separation.[625] With centralization, emissions from heater-treaters would be reduced because fewer heater-treaters would be needed. Colorado described the effectiveness of this restructuring, as follows:

> Removing individual heater-treaters and replacing them with a central gathering facility would eliminate emissions from the heater-treaters. The central gathering facility would be a new source of emissions; however, overall emissions will be reduced. Not only would combustion emissions from the multiple heater-treaters be eliminated, VOC emissions from condensate

[622] *Id.* at 92.
[623] *Id.* at 93. The report further notes that the electricity needs require a "fuel or power source, for which associated emissions need to be quantified."
[624] *Id.* at 93.
[625] CDPHE RP for Heater-Treaters.

> tanks (which would also be removed from wellheads if this technology was implemented) would be eliminated. If a vapor recovery unit (VRU) were used at the central gathering facility, VOCs could be compressed back into the gas stream.[626]

Colorado acknowledges that it would be most cost effective to implement a centralized gathering facility on a new field but indicates that retrofitting a field already set up with infrastructure for wellhead separation would be site-specific and depends on several considerations, including the number of heater-treaters being removed, topography, gas composition, mineral rights, etc. Additional benefits of a centralized gathering facility include reduced truck traffic to wellheads (which can be significant sources of fugitive PM emissions) and a reduction in condensate and water tanks (and their associated fugitive emissions). States should consider requiring or otherwise advocating for centralized gathering facilities for new oil and gas development as a measure to prevent future visibility impairment.

Estimates for NOx emission reductions from the centralization of gas well gathering facilities were not assessed by Colorado other than saying that overall emissions will be reduced. Colorado anticipated that additional time needed for achieving centralization would be site-specific, e.g., depending on gas well density and topographical barriers. Finally, Colorado notes that central gathering facilities would be more efficient to operate, reducing overall energy impacts.

F. NOx EMISSION LIMITS THAT HAVE BEEN REQUIRED FOR HEATERS AND BOILERS

States and local air agencies have adopted NOx limits for existing boilers and heaters, many of which have been in place for more than 20 years and many of which have been strengthened over the years. In Table 42 below, we summarize some of those state and local air pollution requirements. Primarily, a review of California Air District rules was done for this report, because several of those air districts have adopted the most stringent NOx emission limitations.

Table 42 is a summary of the NOx emission limits required of existing boilers and heaters in states and local air districts across the United States. It is important to note that these are limits that, unless otherwise noted, currently apply to existing units and generally required an air pollution control retrofit. These NOx limits were most likely adopted to address nonattainment issues with the ozone and $PM_{2.5}$ NAAQS. Regardless of the reason for adopting the NOx emission limits, what becomes clear in this analysis is that governments have adopted NOx limitations that require low NOx technologies at boilers and heaters as small as 0.4 MMBtu/hr and SCR for units ≥75 MMBtu/hr. The lowest, most broadly applicable NOx limits are those recently adopted by SCAQMD and SJVAPCD. SJVAPCD has a more stringent limit than SCAQMD rules for units between 20 and 75 MMBtu/hr (7 ppm in SJVUAPCD Rule 4320 vs. 9 ppm in SCAQMD Rule 1146), however, it is important to note that for SJVUAPCD's Rules 4306 and 4320, the owner or operator has the option of paying into an annual emissions fee in lieu of

[626] *Id.* at 3.

complying with these limits. For units ≥ 75 MMBtu/hr, the emission limit in SCAQMD Rule 1146 of 5 ppm is more stringent than SJVAPCD's limit of 7 ppm.

Table 42. State/Local Air Agency Natural Gas-Fired Boiler and Heater Rules[627]

State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
CA–SCAQMD	Rule 1146.[628] Adopted 9/9/98 Last revised 12/7/18	≥5 MMBtu/hr Effective 9/5/08	30 ppm (0.036 lb/MMBtu)
		≥5 MMBtu/hr Effective 1/1/14 Atmospheric units	12 ppm (0.015 lb/MMBtu)
		≥75 MMBtu/hr Effective 1/1/13 Excluding thermal fluid heaters	5 ppm (0.0062 lb/MMBtu)
		≥20 and <75 MMBtu/hr Effective 12/7/18 Excluding thermal fluid heaters, certain fire-tube boilers, and units with a previous NOx limit ≤12 and >5 ppm prior to 12/7/18	5 ppm (0.0062 lb/MMBtu)
		≥5 and <20 MMBtu/hr Effective 1/1/15 (or later for units with a previous NOx limit ≤12 ppm prior to 9/5/08) Excluding atmospheric units and thermal fluid heaters	9 ppm (0.011 lb/MMBtu)
		≥5 and <20 MMBtu/hr Effective 12/7/18 (or later for units with a previous NOx limit ≤9 ppm prior to 12/7/18) Fire-tube boilers excluding units with a previous NOx limit ≤12 and >9 ppm prior to 12/7/18	7 ppm (0.0085 lb/MMBtu)
		≥5 MMBtu/hr Effective 12/7/18 (or later for certain units at non-RECLAIM facilities) Thermal fluid heaters	12 ppm (0.015 lb/MMBtu)

[627] This table attempts to summarize the requirements and emission limits of State and Local Air Agency rules applicable to the types of units found in the oil and gas industry, but the authors recommend that readers check each specific rule for the details of how the rule applies to different units, and in case of any errors in this table.
[628] https://ww3.arb.ca.gov/drdb/sc/curhtml/r1146.pdf.

State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
CA–SCAQMD	Rule 1146.1[629] Adopted 10/5/90 Last revised 12/7/18	>2 and <5 MMBtu/hr Effective 9/5/08	30 ppm (0.036 lb/MMBtu)
		>2 and <5 MMBtu/hr Effective 1/1/14 Atmospheric units	12 ppm (0.015 lb/MMBtu)
		>2 and <5 MMBtu/hr Effective 1/1/14 (or later for units with a previous NOx limit ≤12 and >9 ppm prior to 9/5/08) Excluding atmospheric units, thermal fluid heaters, and certain fire-tube boilers	9 ppm (0.011 lb/MMBtu)
		>2 and <5 MMBtu/hr Effective 12/7/18 (or later for units with a previous NOx limit ≤9 ppm prior to 12/7/18) Fire-tube boilers excluding units with ≤12 and >9 ppm prior to 12/7/18	7 ppm (0.0085 lb/MMBtu)
		>2 and <5 MMBtu/hr Effective 12/7/18 (or later for certain units at non-RECLAIM facilities) Thermal fluid heaters	12 ppm (0.015 lb/MMBtu)
CA–SCAQMD	Rule 1146.2[630] Adopted 1/9/98 Last revised 12/7/18	>0.4 and ≤2 MMBtu/hr Effective 1/1/10 Units manufactured or offered for sale	20 ppm (0.024 lb/MMBtu)
		>1 and ≤2 MMBtu/hr Effective 1/1/06 Units more than 15 years old manufactured on or after 1/1/92, except for units at a RECLAIM or former RECLAIM facility	30 ppm (0.037 lb/MMBtu)
		>0.4 and ≤1 MMBtu/hr Effective 1/1/06 Units more than 15 years old manufactured prior to 1/1/00, except for units at a	30 ppm (0.037 lb/MMBtu)

[629] http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1146-1.pdf.
[630] http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1146-2.pdf?sfvrsn=17.

State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
		RECLAIM or former RECLAIM facility	
CA–SJVAPCD	Rule 4320[631] Adopted 10/16/08	>5 and ≤20 MMBtu/hr Effective 1/1/14 Except for certain other units[632]	6 ppmv (0.007 lb/MMBtu)[633]
		>20 MMBtu/hr Effective 1/1/14[634] Except for refinery units,[635] and certain other units[636]	5 ppmv (0.0062 lb/MMBtu)[637]
		>5 MMBtu/hr Effective at the next unit replacement but no later than 1/1/14 Certain units[638]	9 ppmv (0.011 lb/MMBtu)
CA–SJVAPCD	Rule 4306 (Phase 3)[639]	>5 and ≤20 MMBtu/hr	9 ppmv (0.011 lb/MMBtu)

[631] https://www.valleyair.org/rules/currntrules/r4320.pdf.

[632] These certain other units include: (1) those installed prior to 1/1/09 and limited by a Permit to Operate to an annual heat input >1.8 billion Btu/yr but ≤30 billion Btu/yr; (2) units at a wastewater treatment facility firing on less than 50%, by volume, PUC quality gas; and (3) units operated by a small producer in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is rated between 5 and 20 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.

[633] Note, the owner or operator has the option of paying into an annual emissions fee based on total actual emissions, rather than installation of additional NOx controls. These fees are used by the District to achieve cost effective NOx reductions through incentives programs, etc.

[634] The rule allows for a "Staged Enhanced Schedule" for oil field steam generators and refinery units as follows: (1) Initial Limit of 9 ppmv (0.011 lb/MMBtu), effective 7/1/12; and (2) Final Limit of 5 ppmv (0.0062 lb/MMBtu), effective 1/1/14.

[635] Note, refinery unit requirements are the same except that these units have a Standard Schedule limit of 6 ppm, effective 7/1/11.

[636] These certain other units include: (1) those installed prior to 1/1/09 and limited by a Permit to Operate to an annual heat input >1.8 billion Btu/yr but ≤30 billion Btu/yr; (2) units at a wastewater treatment facility firing on less than 50%, by volume, PUC quality gas; and (3) units operated by a small producer in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is rated between 5 and 20 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.

[637] Note, the owner or operator has the option of paying into an annual emissions fee based on total actual emissions, rather than installation of additional NOx controls. These fees are used by the District to achieve cost effective NOx reductions through incentives programs, etc.

[638] These certain other units include: (1) those installed prior to 1/1/09 and limited by a Permit to Operate to an annual heat input >1.8 billion Btu/yr but ≤30 billion Btu/yr; (2) units at a wastewater treatment facility firing on less than 50%, by volume, PUC quality gas; and (3) units operated by a small producer in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is rated between 5 and 20 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.

[639] https://ww3.arb.ca.gov/drdb/sju/curhtml/r4306.pdf.

State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
	Adopted 9/18/03 Last revised 10/16/08	Effective 12/1/08 Except for oil field steam generators, refinery units, and certain other units[640]	
		>20 MMBtu/hr Effective 1/1/14 Except for oil field steam generators, refinery units, and certain other units[641]	6 ppmv (0.007 lb/MMBtu)
		>5 MMBtu/hr Effective 6/1/07 Oilfield steam generators Load-following units[642]	15 ppm (0.036 lb/MMBtu)
		>5 MMBtu/hr Effective 6/1/07 Certain other units[643]	30 ppm (0.036 lb/MMBtu)
CA–SJVAPCD	Rule 4307[644] Adopted 12/15/05 Last revised 4/21/16	>2 and ≤5 MMBtu/hr Existing units	30 ppm (0.036 lb/MMBtu)
		>2 and ≤5 MMBtu/hr New or replacement units Effective 1/1/16 Atmospheric units Non-atmospheric units	 12 ppm (0.014 lb/MMBtu) 9 ppm (0.011 lb/MMBtu)
CA–SJVAPCD	Rule 4308[645] Adopted 10/20/05 Last revised 11/14/13	>0.4 and <2 MMBtu/hr Effective 1/1/15 Point-of-sale[646] PUC gas Non-PUC gas	 20 ppm (0.024 lb/MMBtu) 30 ppm (0.036 lb/MMBtu)
CA–SMAQMD	Rule 411[647]	Effective 10/27/09	

[640] These certain other units include: (1) load-following units; (2) units limited by a Permit to Operate to an annual heat input 9–30 billion Btu/yr; and (3) units in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is > 5 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.
[641] *Id*.
[642] Load-following units must meet a limit of 9 ppm under the Enhanced Schedule, with a compliance date of 12/1/08.
[643] These certain other units include: (1) refinery units >5 and ≤65 MMBtu/hr (note that units >65 and ≤110 MMBtu/hr are required to meet a limit of 25 ppm (0.031 lb/MMBtu and units >110 MMBtu/hr are required to meet a limit of 5 ppm); (2) units limited by a Permit to Operate to an annual heat input 9–30 billion Btu/yr; and (3) units in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is > 5 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.
[644] https://www.valleyair.org/rules/currntrules/Rule4307.pdf.
[645] https://www.valleyair.org/rules/currntrules/03-4308_CleanRule.pdf.
[646] This point-of-sale rule covers units supplied, sold, offered for sale, installed, or solicited for installation.
[647] http://www.airquality.org/ProgramCoordination/Documents/rule411.pdf.

State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
	Adopted 2/2/95 Last revised 8/23/07	New and existing units ≥1 and <5 MMBtu/hr ≥5 and ≤20 MMBtu/hr >20 MMBtu/hr	 30 ppm (0.036 lb/MMBtu) 15 ppm (0.036 lb/MMBtu) 9 ppm (0.011 lb/MMBtu)
CA–SMAQMD	Rule 414[648] Adopted 8/1/96 Last revised 10/25/18	>0.4 and <1 MMBtu/hr Effective 10/25/18 (date of last revision) Point-of-sale[649]	20 ppm (0.024 lb/MMBtu)
CA–VCAPCD	Rule 74.15.1[650] Adopted 5/11/93 Last revised 6/23/15	≥1 and <5 MMBtu/hr Effective 1/1/16 Existing units New and Replacement: Atmospheric units Pressurized Units	 30 ppm (0.036 lb/MMBtu) 12 ppm (0.014 lb/MMBtu) 9 ppm (0.011 lb/MMBtu)
CA–Santa Barbara County APCD	Rule 361[651] Adopted 1/17/08 Last revised 6/20/19	>2 and <5 MMBtu/hr Existing units Installed and modified (after 1/1/20): Atmospheric units Non-atmospheric Units	 30 ppm (0.036 lb/MMBtu) 12 ppm (0.014 lb/MMBtu) 9 ppm (0.011 lb/MMBtu)
CA–Santa Barbara County APCD	Rule 342[652] Adopted 3/10/92 Last revised 6/20/19	≥5 MMBtu/hr Existing units Installed and modified (after 1/1/20): ≥5 and ≤20 MMBtu/hr >20 MMBtu/hr	 30 ppm (0.036 lb/MMBtu) 9 ppm (0.011 lb/MMBtu) 7 ppm (0.0085 lb/MMBtu)
CA–Feather River AQMD	Rule 3.23[653] Adopted 10/3/16	>0.4 and <1 MMBtu/hr Effective 1/1/17 Point-of-sale[654]	20 ppm (0.024 lb/MMBtu)
CA–Bay Area AQMD	Regulation 9 Rule 7[655] Adopted 9/16/92	>2 and ≤5 MMBtu/hr Effective 1/1/15	30 ppm (0.036 lb/MMBtu)

[648] http://www.airquality.org/ProgramCoordination/Documents/rule414.pdf.
[649] This point-of-sale rule covers units manufactured, distributed, offered for sale, sold, or installed.
[650] http://www.vcapcd.org/Rulebook/Reg4/RULE%2074.15.1.pdf.
[651] https://www.ourair.org/wp-content/uploads/rule361.pdf.
[652] https://www.ourair.org/wp-content/uploads/rule342.pdf.
[653] https://ww3.arb.ca.gov/drdb/fr/curhtml/r3-23.pdf.
[654] This point-of-sale rule covers units offered for sale, sold, or installed.
[655] https://www.baaqmd.gov/~/media/dotgov/files/rules/reg-9-rule-7-nitrogen-oxides-and-carbon-monoxide-from-industrial-institutional-and-commercial-boiler/documents/rg0907.pdf?la=en.

State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
		>5 and <10 MMBtu/hr Effective 1/1/15 ≥10 and <20 MMBtu/hr Effective 1/1/14 ≥20 and <75 MMBtu/hr Effective 1/1/14 ≥75 MMBtu/hr Effective 1/1/14 Excluding thermal fluid heaters	15 ppm (0.036 lb/MMBtu) 15 ppm (0.036 lb/MMBtu) 9 ppm (0.011 lb/MMBtu) 5 ppm (0.0062 lb/MMBtu)
TX- Houston-Galveston-Brazoria Area	30 TAC 117.2010(c)(1) Emission Specs for 8hr ozone demo[656]	Emission specs for mass emission cap and trade	0.036 lb/MMBtu (or, alternatively 30 ppm @ 3% O2)
TX	30 TAC 117.3205(a) [657]	Statewide Point-of-sale[658] Effective 7/1/02 >0.4 and ≤2 MMBtu/hr	30 ppm or 0.037 lb/MMBtu
MA	310 CMR 7.26(30)[659]	≥10 and <40 MMBtu/hr Effective 9/14/01	0.0350 lb/MMBtu
NY	6 CRR-NY 227-2.4[660]	>25 and ≤100 MMBtu/hr	0.05 lb/MMBtu
GA	Rule 391-3-1-.02.(2)(III)1.[661]	Effective 5/1/00 Fuel-burning equipment 45 county area – ozone May 1 – September 30 each year	30 ppm

[656] https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=117&rl=2010.

[657] https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=117&rl=3205.

[658] Applies to units sold, distributed, installed, or offered for sale.

[659] https://www.mass.gov/doc/310-cmr-700-air-pollution-control-regulations/download.

[660] RACT for major sources of NOx: https://govt.westlaw.com/nycrr/Document/I4e978e48cd1711dda432a117e6e0f345?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default).

[661] http://rules.sos.ga.gov/gac/391-3-1.

Most stringent NOx Limits of State/Local Rules:

5 ppm (0.0062 lb/MMBtu)……Units ≥75 MMBtu/hr
5–12 ppm (0.0062–0.015 lb/MMBtu) …….…….…….…… Units >2 and <75 MMBtu/hr
20 ppm (0.024 lb/MMBtu)……. Units ≤2 MMBtu/hr

As Table 42 shows, several state and local air pollution control agencies have adopted NOx emission limits for boilers and heaters that reflect the application of low NOx burner technologies, and reflect SCR for units ≥75 MMBtu/hr. These air agencies have thus found that the levels of NOx control listed in Table 42, including NOx limits as low as 5 ppm for larger units, in the range of 5–12 ppm for smaller units, and as low as 20 ppm for very small units, providing relevant examples for states to consider in their second round haze plans to help make reasonable progress towards remedying existing visibility impairment. The fact that these limits could apply to modified units >2 MMBtu/hr means that the states consider retrofit controls to meet the emission limits in Table 42 above to be cost effective, and should also consider the cost effectiveness of retrofitting units >5 MMBtu/hr to meet NOx limits as low as 2–3.5 ppm based on the work being done in the SJVAPCD.

G. SUMMARY – NO_x CONTROLS FOR NATURAL GAS-FIRED HEATERS AND BOILERS

The above analyses and rule data demonstrate that numerous state and local air agencies have found that low NOx burner technology is a cost effective retrofit NOx control for boilers and heaters >5 MMBtu/hr with costs ranging from $545/ton to $5,232/ton. Smaller units ≤5 MMBtu/hr can be replaced with new units with low NOx burner technology at costs ranging from $4,055/ton to $10,809/ton. Low NOx burner technologies can generally meet limits down to 5–6 ppm, with the potential for emerging technologies to meet NOx levels lower than 5 ppm. For most units, including atmospheric units, a blower may be required to mix the fuel and air prior to combustion. It is possible to reach NOx levels of 9 ppm for non-atmospheric units and 12 ppm for atmospheric units without the use of FGR.[662]

Further, SJVAPCD has found that SCR is cost effective for larger units with costs ranging from $1,025/ton to $6,149/ton to meet NOx levels as low as 2.5 ppm. For the lowest NOx limit of 5–6 ppm currently applicable to units under rules adopted by SCAQMD and SJVAPCD, SCR is presumably necessary to meet these limits.

As states evaluate regulation of NOx emissions from boilers and heaters, there are several factors to consider, such as draft type (i.e., atmospheric vs. non-atmospheric), operating capacity factor, and size. Nonetheless, given the numerous local NOx limits in Table 42 above that reflect operation of low NOx burner technology, and SCR for larger units, these controls for units of all sizes should generally be considered as cost effective measures available to make reasonable progress from boilers, reboilers, and

[662] *See, e.g.,* Santa Barbara County APCD 2019 Draft Staff Report.

heaters, given that similar sources have assumed similar costs of control to meet Clean Air Act requirements.

VIII. ADDRESSING VISIBILITY-IMPAIRING EMISSIONS FROM FLARING AND THERMAL INCINERATION OF EXCESS GAS AND WASTE GAS

Gas flaring is a process to combust excess or waste gases from oil wells, gas processing plants, or oil refineries. Flaring is intended as a means of disposal of excess gas as a safety measure and is also done to relieve pressure in gas pipelines. Combustion of excess or waste gas can also be accomplished with thermal incinerators rather than flaring.[663] Combustion of excess gas whether done through flaring or thermal incineration is also a VOC control device, as the combustion of the gas destroys most of the VOCs. However, the extent to which VOC emissions are effectively destroyed depends on the design and operation of the combustion device.

There are several processes associated with oil and gas development in which excess gas is flared or combusted, including the following: during testing of a new oil or gas well, when natural gas co-occurs with a new oil well, at gas pipeline headers and at gas processing plants when needed to relieve pressure, at gas compressor stations to combust vapors captured by a dehydrator unit, at gas processing plants and at oil refineries when an upset occurs or to allow maintenance of equipment, and at gas sweetening plants.[664]

A flare system is a thermal oxidation process using an open flame. It consists of an elevated flare stack through which the waste or excess gas stream flows, where it is combusted at the tip of the stack producing a flame. This is sometimes referred to as a "candlestick" flare. A thermal incinerator, which is also called a direct flame incinerator, thermal oxidizer, or an afterburner, is a thermal oxidation process that occurs in an enclosed combustion chamber. The temperature of the waste gas is raised in the combustion chamber in the presence of oxygen above its autoignition point by passing the gas through a flame which is maintained by the waste gas and auxiliary fuel, and combustion of the waste gas occurs. More specific descriptions of these control devices are provided below. The purpose of both a flare and a thermal incinerator is to combust the excess or waste gas and reduce VOC emissions.

A. FLARING SYSTEM

EPA describes a flare system as follows:

> Flaring is a high-temperature oxidation process used to burn waste gases containing combustible components such as volatile organic compounds (VOCs), natural gas (or

[663] *See* Alberta Energy Regulator, EnerFAQS, Flaring and Incineration, *available at:* https://www.aer.ca/providing-information/news-and-resources/enerfaqs-and-fact-sheets/enerfaqs-flaring.

[664] *See,* e.g., Ohio EPA, Understanding the Basics of Gas Flaring, November 2014, *available at*: https://www.epa.state.oh.us/portals/27/oil%20and%20gas/basics%20of%20gas%20flaring.pdf. *See also* Eman, Eman A., Gas Flaring in Industry: An Overview, Petroleum & Coal 57(5) 532-555, 2015, *available at:* http://large.stanford.edu/courses/2016/ph240/miller1/docs/emam.pdf.

> methane), carbon monoxide (CO), and hydrogen (H_2). The waste gases are piped to a remote, usually elevated location, and burned in an open flame in ambient air using a specially designed burner tip, auxiliary fuel, and, in some cases, assist gases like steam or air to promote mixing for nearly complete (e.g., ≥ 98%) destruction of the combustible components in the waste gas. Note that destruction efficiency is the percentage of a specific pollutant in the flare vent gas that is converted to a different compound (such as carbon dioxide [CO_2], carbon monoxide, or another hydrocarbon intermediate), while combustion efficiency is the percentage of hydrocarbon in the flare vent gas that is completely converted to CO_2 and water vapor. . . .
>
> Combustion requires three ingredients: fuel, an oxidizing agent (typically oxygen in the air), and heat (or ignition source). Flares typically operate with pilot flames to provide the ignition sources, and they use ambient air as the oxidizing agent. The waste gases to be flared typically provide the fuel necessary for combustion. Combustible gases generally have an upper and lower flammability limit. The upper flammability limit (UFL) is the highest concentration of a gas in air that is capable of burning. Above this flammability limit, the fuel is too rich to burn. The lower flammability limit (LFL) is the lowest concentration of the gas in air that is capable of burning. Below the LFL, the fuel is too lean to burn. Between the UFL and the UFL, combustion can occur. Completeness of combustion in a flare is governed by flame temperature, residence time and flammability of the gas in the combustion zone, turbulent mixing of the components to complete the oxidation reaction, and available oxygen for free radical formation. Combustion is complete if all hydrocarbons and CO are converted to CO_2 and water. Incomplete combustion results in some hydrocarbons or CO discharged to the flare being unaltered or converted to other organic compounds such as aldehydes or acids.[665]

Flares, if operated in a manner to provide for complete combustion, are intended to destroy hydrocarbons and VOCs. Flaring also converts methane to CO_2. Both are greenhouse gases, but methane is a more powerful greenhouse gas.[666] EPA indicates that properly operated flares should achieve 98% destruction efficiency of VOCs.[667] However, according to EPA studies, flares "can operate at a wide range of Destruction and Removal Efficiency (DRE)." As a result, although flares are a VOC control device, flares are also a source of VOC emissions especially when not designed or operated in a manner to achieve high levels of DRE. Further, "[s]mall amounts of uncombusted vent gas will escape the flare combustion zone along with products of incomplete combustion,"[668] which can add to VOC emissions as well as methane emitted from the flare. Flaring of natural gas also results in emissions of NOx, as well as particulate matter emissions of carbon particles (soot) and unburned hydrocarbons.

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[665] EPA, VOC Destruction Controls, Chapter 1 Flares, August 2019, at 1-1, *available at:* https://www.epa.gov/sites/production/files/2019-08/documents/flarescostmanualchapter7thedition_august2019vff.pdf.

[666] *See* https://www.epa.gov/ghgemissions/understanding-global-warming-potentials#Learn%20why

[667] *See* EPA, Air Pollution Control Fact Sheet, Flare, EPA-452/F-03-019, *available at:* https://www3.epa.gov/ttn/catc/dir1/fflare.pdf.

[668] Shah, Tejas, Ramboll Environ (EPA Contractor), Greg Yarwood (Ramboll Environ), Alison Eyth (EPA), and Madeleine Strum (EPA), Composition of Organic Gas Emissions from Flaring Natural Gas, August 18, 2017, at 6, *available at:* https://www.epa.gov/sites/production/files/2017-11/documents/organic_gas.pdf.

Flaring is also a significant cause of SO_2 emissions when sour gas or acid gas is flared. Although the sulfur content for gas to be considered sour gas can vary by state, gas with a hydrogen sulfide (H_2S) content of 5.7 milligrams per cubic meter of gas (about 4 ppm) is generally considered to be sour gas.[669] Among other places in the United States, sour gas exists in areas of New Mexico, Texas, Wyoming, and North Dakota.

In terms of air pollution control measures to apply directly to flare design and operation, controls and techniques to ensure or improve DRE are the primary pollution control for natural gas flares. These are discussed further below in Section E.

B. THERMAL INCINERATION

Thermal incineration of gases is generally able to result in more complete combustion due to the greatly improved ability to control fuel and air flow, temperature, turbulence, and residence time.[670] Thus, incineration of excess gases may result in greater destruction of hydrocarbons and lower VOC emissions than if the same amount of gas was flared. As with flaring, while thermal incineration is a VOC control technology, the incineration of waste gas does result in emissions of NOx and some particulate matter as a result of incomplete combustion, along with CO_2. Further, when sour gas or acid gas is combusted in a thermal incinerator, SO_2 will be emitted. In the absence of SO_2 pollution controls, incineration of waste or excess gases may not be the best choice compared to flaring for gas with sulfur compounds, because the elevated height of the flare can allow for greater dispersion of the SO_2 emissions.[671] On the other hand, use of a thermal incinerator to combust excess or waste gas allows for the addition of an acid gas scrubber to remove SO_2 and also could allow for use of the thermal heat produced by the waste gas combustion, whereas those opportunities for SO_2 control and for getting some energy benefit from the combustion of waste gases do not exist with a flare. Further, low NOx combustion controls exist for thermal incinerators. The pollution controls to apply directly to thermal incinerators are discussed further below in Section F.

The best method to reduce/eliminate air emissions from flaring or incineration of excess or waste gas is to avoid the need for combustion of the gases altogether. The options for doing so are discussed further below in Section D.

C. SO_2 EMISSIONS FROM THE DESTRUCTION OF SOUR GAS WASTE STREAMS

For sour gas, the sulfur compounds must be removed to produce pipeline quality natural gas. H_2S is the sulfur compound of most concern in sour gas because the majority of sulfur compounds in sour gas are in the form of H_2S and because it is it is very poisonous, explosive and corrosive. According to the Occupational Safety and Health Administration (OSHA), exposure to H_2S can cause significant eye and respiratory irritation and exposure to high concentrations of H_2S "can cause shock, convulsions, inability

[669] http://naturalgas.org/naturalgas/processing-ng/.
[670] *See*, e.g., EPA, Air Pollution Control Technology Fact Sheet, Thermal Incinerator, EPA-452/F-03-022, *available at:* https://www3.epa.gov/ttnchie1/mkb/documents/fthermal.pdf.
[671] *See* https://www.aer.ca/providing-information/news-and-resources/enerfaqs-and-fact-sheets/enerfaqs-flaring#what.

to breathe, extremely rapid unconsciousness, coma and death."[672] It is also very corrosive to gas pipelines and can be explosive. Thus, H_2S has to be removed from sour gas streams before the gas can be sent into gas pipelines to consumers. H_2S is removed from the gas in gas sweetening plants, usually via an amine process which separates the H_2S and also CO_2 from the natural gas.[673] Since 1985, the EPA's NSPS have required gas sweetening plants with a capacity of more than 2 long tons per day of H_2S in the acid gas to either 1) completely reinject the acid gas stream into oil- or gas-bearing geologic strata or 2) to use a sulfur reduction and removal technology to reduce SO_2 emissions from the acid gas before it is flared or combusted.[674] Sweetening plants that aren't subject to such requirements may be allowed to flare the acid gas stream or incinerate the gas stream, either of which could release very significant quantities of SO_2 emissions, although it is not clear that any such plants continue to operate. However, even for gas sweetening plants required to control the H_2S by reinjecting into the geologic strata or by using a sulfur recovery unit or other control method, SO_2 emissions from flaring or from thermal incineration is of significant concern. For those plants, flaring episodes occur due to malfunctions or due to maintenance or possibly for other reasons.[675] When flared or combusted, the H_2S in the acid gas stream converts to SO_2, which is a significant visibility-impairing pollutant. EPA states that "100 tons or more of SO_2 can be released in [a flaring episode] within a 24-hour period."[676] In the case of flaring of acid gas streams, the only methods to reduce SO_2 emissions directly from flaring acid gas streams at gas sweetening plants are to reduce or eliminate flaring episodes. Methods to reduce such flaring episodes are discussed in the next section.

D. CONTROL MEASURES, TECHNIQUES, AND OPERATING PRACTICES TO PREVENT FLARING OR INCINERATION OF EXCESS OR WASTE GAS

Prevention of flaring/incineration of excess or waste gases is the best method to reduce the air emissions from this source category. It will also prevent NOx, particulate matter, air toxic emissions including formaldehyde, and CO_2 emissions, as well as any VOCs and methane that are not destroyed in the combustion process. Available methods and techniques to reduce flaring or thermal combustion of excess or waste gas are discussed below.

1. REDUCING FLARING AT THE WELL SITE

In 2016, the U.S. Bureau of Land Management (BLM) issued a rule intended "to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas production on onshore Federal and Indian (other than Osage Tribe) leases."[677] This rule is often referred to as the "BLM Waste Prevention Rule."

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[672] OHSA Fact Sheet, Hydrogen Sulfide (H_2S), *available at:* https://www.osha.gov/OshDoc/data_Hurricane_Facts/hydrogen_sulfide_fact.pdf.
[673] *See*, e.g., http://operoenergy.com/gas-sweetening-technologies/.
[674] *See* 40 C.F.R. Subparts LLL and OOOO.
[675] *See* EPA, Enforcement Alert, Frequent, Routine Flaring May Cause Excessive, Uncontrolled Sulfur Dioxide Releases, October 2000, *available at:* https://www.epa.gov/sites/production/files/documents/flaring.pdf.
[676] *Id.*
[677] 81 Fed. Reg. 83,008 (Nov. 18, 2016).

The fact sheet issued by EPA at the time of the rulemaking stated that the rule would phase in, over several years, a flaring limit per development oil well that ratcheted down over time.[678] There were several options for complying with the flaring limits, including: "expanding gas-capture infrastructure (e.g., installing compressors to increase pipeline capacity, or connecting wells to existing infrastructure through gathering lines); adopting alternative on-site capture technologies (e.g., compressing the natural gas or stripping out natural gas liquids and trucking the product to a gas processing plant); or temporarily slowing production at a well to minimize losses until capture infrastructure is installed."[679] The rule also required operators to evaluate opportunities for gas capture before drilling a development oil well, which were to be submitted with an Application for a Permit to Drill and which were to be shared with midstream gas capture companies "to facilitate timely pipeline development. . . ."[680] In 2018, the BLM rescinded the gas capture requirements of the 2016 rule "in favor of an approach that relies on State and tribal regulations and reinstates the NTL-4A standard for flaring in the absence of State or tribal regulations."[681] The 2018 BLM rulemaking describes the NTL-4A standard as the BLM's existing policy from before the 2016 BLM Waste Prevention Rule, which was published in the Federal Register in 1979 (44 Fed. Reg. 76600, Dec. 27, 1979)[682] and "governed venting and flaring from BLM-administered leases for more than 35 years."[683] The BLM has clearly indicated that states could regulate flaring. Indeed, development of the BLM Waste Prevention Rule considered "analogous state requirements related to waste of oil and gas resources," and the BLM "reviewed requirements from Alaska, California, Colorado, Montana, North Dakota, Ohio, Pennsylvania, Utah, and Wyoming."[684] Further, EPA has been requiring the capture and collection of excess gas from the drilling of natural gas wells under the NSPS since 2012.[685]

Thus, there are example state and federal rules[686] and methods that states should adopt, if not already in place, to reduce flaring of gas associated with oil wells, that would not only reduce visibility-impairing pollution from flaring, but that would also reduce air toxics and greenhouse gases emissions as well as ensure that the natural gas produced along with oil at oil wells is utilized as an energy source rather than just flared or combusted to destroy the VOCs.

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[678] *See* BLM Fact Sheet on Methane and Waste Prevention Rule, at 3, *available at:* https://www.doi.gov/sites/doi.gov/files/uploads/methane_waste_prevention_rule_factsheet_final.pdf.

[679] *Id. See also* Clean Air Task Force's publication entitled "Putting Out the Fire: Reducing Flaring in Tight Oil Fields," April 2, 2015, for additional discussion of additional alternatives to flaring excess gas, *available at:* https://www.catf.us/resource/putting-out-the-fire/; and U.S.DOE, Office of Fossil Energy, Natural Gas Flaring and Venting: State and Federal Regulatory Overview, Trends, and *see* Impacts, June 2019, at 50-55 *available at:* https://www.energy.gov/sites/prod/files/2019/08/f65/Natural%20Gas%20Flaring%20and%20Venting%20Report.pdf.

[680] *Id.*

[681] 83 Fed. Reg. 49,184 at 49,188 (Sept. 28, 2018).

[682] 83 Fed. Reg. 49,184 at 49,185 (Sept. 28, 2018).

[683] 83 Fed. Reg. 49,189 at 49,185 (Sept. 28, 2018).

[684] 81 Fed. Reg. 83,008 at 83,019 (Nov. 18, 2016).

[685] 40 C.F.R. Part 60, Subpart OOOO, §60.5375.

[686] The U.S. Department of Energy has a recent report that summarizes the state and federal rules on flaring. *See* U.S.DOE, Office of Fossil Energy, Natural Gas Flaring and Venting: State and Federal Regulatory Overview, Trends, and Impacts, June 2019, at 20-48.

2. REDUCING FLARING AT COMPRESSOR STATIONS, GAS PROCESSING PLANTS, AND GAS SWEETENING PLANTS

As discussed above, flaring at compressor stations and gas processing plants including gas sweetening plants, is often due primarily to plant upsets and maintenance. Flaring of sour gas or acid gas streams at gas sweetening plants can be a significant source of visibility-impairing SO_2, and thus reducing flaring emissions at gas sweetening plants could be an effective reasonable progress measure to address regional haze. Reducing flaring will also reduce the NOx, PM, VOCs, and CO_2 emitted from the flares.

EPA listed the following measure to prevent excess flaring at refineries, and this same approach can be used to identify methods and techniques to reduce flaring at natural gas compressor stations and at gas processing facilities:

> Conduct a root-cause analysis of each flaring incident to identify if any equipment and/or operational changes are necessary to eliminate or minimize that cause so as to reduce or avoid future flaring events. As appropriate, corrective measures should be taken and implemented. If the analysis shows that the same cause has happened before, the incident should not be considered a malfunction and corrective measures should be taken to prevent future occurrences….[687]

In addition, it is imperative to ensure that there is adequate gas handling capacity at the various processing points in a compressor station, gas processing or gas sweetening plant. EPA states that "[r]edundant units can prevent flaring by allowing one unit to operate if the other needs to be shut down for maintenance or an upset. . . ."[688] Thus, adding excess capacity and/or backup units could be very important in reducing the amount of flaring due to upsets.

As part of their evaluation of measures to provide for reasonable progress towards the national visibility goal, states should evaluate the flaring episodes at the compressor station and at gas processing plants, including the collection of data on the length of time of each flaring episode, frequency, and causes. For plants that have more frequent flaring episodes, and especially for those plants flaring sour gas or acid gas streams from a gas sweetening plant, states should evaluate the root causes of upsets that cause flaring episodes to determine if measures, such as improved maintenance or duplicative parts or processing units, can be employed to reduce flaring episodes.

E. POLLUTION CONTROL TECHNIQUES FOR FLARES

EPA has described the control techniques for flares, based on the federal requirements in EPA's New Source Performance Standards (NSPS) (at 40 C.F.R. §60.8) and EPA's National Emission Standards for Hazardous Air Pollutants (NESHAPs) (at 40 C.F.R. §63.11) as follows:

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[687] *See* EPA, Enforcement Alert, Frequent, Routine Flaring May Cause Excessive, Uncontrolled Sulfur Dioxide Releases, October 2000, at 3 *available at:* https://www.epa.gov/sites/production/files/documents/flaring.pdf.
[687] 81 Fed. Reg. 83,008 (Nov. 18, 2016).
[688] *Id.*

> At a minimum, these [NSPS and NESHAP] rules require flares to be:
>
> - Designed and operated with no visible emissions using EPA [test] Method 22 (except for periods not to exceed 5 minutes in 2 hours);
> - Operated with a flame present at all times, confirmed by the use of a thermocouple or equivalent device;
> - Used only when the net heating value of the gas to be combusted is 300 BTU per standard cubic foot (BTU/scf) or greater (if the flare is steam- or air-assisted), or 200 BTU/scf or greater (if the flare is nonassisted); and
> - Designed for and operated with an exit velocity less than 60 feet per second (f/sec). An exit velocity of greater than 60 ft/sec but less than 400 ft/sec may be used if the net heating value of the gas being combusted is sufficiently high.[689]

Other requirements that must be met include that the flare must be operated at all times in a manner consistent with good air pollution control practices for minimizing emissions, and that flaring operations must be monitored to ensure they are operated and maintained according to their design.[690] EPA has listed several other more detailed guidelines to ensure flares are properly operated.[691] Proper training of employees is also an important part of ensuring the flares are properly operated. States must require documentation of each flaring episode to ensure that the flaring regulations of the NSPS and NESHAPs have been complied with, as well as to ensure that adequate records of the amount of gas flared and causes of flaring are maintained and reported.

The above operating standards are required for all flaring. Alternatives to flaring include 1) gas capture to decrease or eliminate flaring as discussed above, or 2) combusting the gas in a thermal incinerator which can provide for greater destruction of VOC emissions. Also, additional air pollution controls can be used at an incinerator, as is discussed below.

F. POLLUTION CONTROL TECHNIQUES FOR THERMAL INCINERATION OF EXCESS OR WASTE GAS

As discussed above, waste gases or excess gas can be disposed of via thermal incineration rather than a flare. EPA describes a thermal incinerator, or a thermal oxidizer, as follows:

> Incineration, or thermal oxidation is the process of oxidizing combustible materials by raising the temperature of the material above its auto-ignition point in the presence of oxygen, and maintaining it at high temperature for sufficient time to complete combustion to carbon dioxide and water. Time, temperature, turbulence (for mixing), and the availability of oxygen all affect the rate and efficiency of the combustion process. These factors provide the basic design parameters for VOC oxidation systems (ICAC, 1999).

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[689] *See* EPA, Enforcement Alert, EPA Enforcement Targets Flaring Efficiency Violations, August 2012, at 1, *available at:* https://www.epa.gov/sites/production/files/documents/flaringviolations.pdf.
[690] *Id.* at 2; see also 40 C.F.R. §63.172(e) and 60.482-10.
[691] *See*, e.g., EPA, Enforcement Alert, EPA Enforcement Targets Flaring Efficiency Violations, August 2012, at 3.

> A straight thermal incinerator is comprised of a combustion chamber and does not include any heat recovery of exhaust air by a heat exchanger (this type of incinerator is referred to as a recuperative incinerator).
>
> The heart of the thermal incinerator is a nozzle-stabilized flame maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. Upon passing through the flame, the waste gas is heated from its preheated inlet temperature to its ignition temperature. . . The required level of VOC control of the waste gas that must be achieved within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. The nominal residence time of the reacting waste gas in the combustion chamber is defined as the combustion chamber volume divided by the volumetric flow rate of the gas. . . .[692]

EPA indicates that thermal incinerators can achieve 98% to 99.9999% destruction of VOCs.[693] However, thermal incinerators typically require auxiliary fuel to preheat the waste gas and sustain the heat necessary for destruction of VOCs.[694] The high temperature reaction necessary in an incinerator to destroy the VOC and air toxic emissions can result in increased NOx emissions. To limit NOx emissions, low NOx burners or other low NOx processes are available control measures to integrate into the thermal incinerator to limit NOx emissions.[695] Thus, for any thermal incinerators or thermal oxidizers, low NOx burners or other low NOx emission systems should be installed to minimize NOx emissions from the thermal incinerator.

It is important to note that thermal incinerators can be used at gas sweetening plants along with acid gas scrubbers to remove the SO_2 that is formed from combusting the H_2S in the acid gas. Such a system could potentially be used as an SO_2 control,[696] or it could be used as a backup system for a sulfur recovery unit when it is down due to malfunction, maintenance, or during startup or shutdown.[697] This method of control could greatly reduce if not eliminate the SO_2 emissions that occur at gas sweetening

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[692] EPA, Air Pollution Control Technology Fact Sheet, Thermal Incinerator, EPA-452/F-03-022, at 4, *available at:* https://www3.epa.gov/ttnchie1/mkb/documents/fthermal.pdf.

[693] *Id.* at 5.

[694] *Id. See also* EPA, Control Cost Manual, Section 3, Chapter 2 – Incinerators and Oxidizers, at 2-3 to 2-4, *available at:* https://www.epa.gov/sites/production/files/2017-12/documents/oxidizersincinerators_chapter2_7theditionfinal.pdf.

[695] *See*, e.g., Zeeco Products & Applications, Incinerators & Thermal Oxidizers Multi-Stage Low-NOx Incinerator/Thermal Oxidizer, *available at:* https://www.zeeco.com/incinerators/incinerators-therm-ox-multi-stage.php. *See also* AERON, Thermal Oxidation/Incineration Systems, Ultra-Low Emissions Systems, *available at:* http://www.aereon.com/enclosed-combustion-systems/ultra-low-emissions-systems/certified-ultra-low-emissions-burner-ceb.

[696] *See*, e.g., AERON, Thermal Oxidation/Incineration Systems, Tail Gas Incineration Units, which discusses acid flue gas scrubbers as an available option, *available at:* http://www.aereon.com/enclosed-combustion-systems/thermal-oxidationincineration-systems/tail-gas-incineration-units.

[697] *See* Envitech, Industrial Gas Cleaning Systems, Air Pollution Control Innovations, Refinery Sulfur Recovery Unit (SRU) SO_2 Scrubber for Startup, Shutdown, and Malfunctions, *available at:* https://www.envitechinc.com/air-pollution-control-innovations/refinery-sulfur-recovery-unit-sru-so2-scrubber-for-startup-shutdown-and-malfunctiong-post-title-here.

facilities when the gas injection well or sulfur recovery unit is not in operation due to malfunctions or maintenance.

In many respects, combusting of waste gases and/or excess gas in a thermal incinerator seems more preferable from an air pollutant perspective than flaring, because thermal incineration will likely result in a greater destruction efficiency of VOCs and because control options exist for limiting emissions of NOx and of SO_2 (to the extent that sour gas or an acid gas stream is what was being flared). Further, there could be an option of gathering and routing excess gas emission from multiple points to a centralized thermal incinerator. Moreover, continuous emission monitoring systems (CEMS) could be installed in the thermal oxidizer stack to provide valuable actual emissions data due to the combustion of waste or excess gases, including information to ensure that optimal VOC destruction efficiency is achieved.

However, the need for auxiliary fuel in thermal combustion means more CO_2 will be emitted than if the gas stream was flared. Yet, there are options for thermal incinerators that recover the waste heat, which are called recuperative oxidizers or regenerative oxidizers.[698] The recovered waste heat can be used to preheat the incoming air which would reduce the amount of supplemental fuel required.[699]

To sum up, use of a recuperative or regenerative thermal incinerator (thermal oxidizer) with low NOx combustion controls, CEMs, and an acid gas scrubber if necessary, seems to be a preferable alternative to flaring of waste gas streams. Such a system would provide better control of VOCs, reduce NOx emissions from combustion of the waste gas via the use of low NOx combustion controls, and provide the ability to add an acid gas scrubber to remove SO_2 (which is a control option that does not exist for flares).

G. SUMMARY – BEST OPTIONS FOR CONTROLLING EMISSIONS DUE TO FLARING OR INCINERATION OF EXCESS OR WASTE GAS

Based on the above analysis, it seems evident that prevention of flaring through the collection of excess gas is the most beneficial option for reducing emissions from flaring. Capturing and using the natural gas that is produced at oil wells would ensure that the energy value of the gas is not wasted by being combusted in a flare or in an incinerator, and it is very likely that the end user of the gas would at least be using some level of NOx and VOC control.

Thermal incineration should be considered in lieu of flaring for waste gases due to the pollution controls for NOx and SO_2 that are available and because of the improved operation and VOC destruction. Moreover, use of a thermal incinerator provides the opportunity to monitor and accurately track emissions from the combustion of waste or excess gases with the use of CEMS.

At gas processing facilities including gas sweetening plants, it is important that the causes of flaring episodes be documented and assessed to determine any changes in operations, training, and/or in equipment that may be needed to reduce plant upsets and maintenance during which flaring occurs due

[698] EPA, Air Pollution Control Technology Fact Sheet, Thermal Incinerator, EPA-452/F-03-022, at 5.
[699] *Id.*

to the unavailability of plant equipment to process the gas stream. As stated above, adding excess capacity and/or backup units could be very effective in reducing the amount of flaring due to upsets. Proper maintenance of equipment is also key, as is appropriate training of staff to minimize flaring episodes due to maintenance and upsets.

In general, states should ensure that their rules require companies to document all flaring episodes, including the cause, duration of the flaring, flue gas flow, actions taken to stop the flaring, and emission estimates, and to submit such documentation to the state or local air agency in a timely manner. This data will best enable states to develop appropriate rules and procedures to limit the various causes of flaring emissions within its state.

Overall, the goal of state programs to address flaring emissions should be to minimize flaring to the maximum extent possible. However, for those situations when flaring does occur, it is imperative that the flares be operated in accordance with NSPS and NESHAP requirements, and that the flares are operated and maintained in accordance with their design. Moreover, to ensure these requirements are being met and to ensure that flaring is minimized to the maximum extent possible, the state or local air agencies must conduct thorough oversight into the causes of flaring episodes, to ensure that the facility is being maintained and operated in a manner to minimize all flaring episodes to the extent possible.

Attn: Mark Jones & Cember Hardison
New Mexico Environment Department

May 22, 2020

Dear Mr. Jones and Ms. Hardison,

Thank you for the opportunity to discuss the options available for best mitigating haze-causing pollutants from sources in the oil and gas sector in New Mexico. We appreciate your work to develop a strong regional haze state implementation plan (SIP). While this letter is focused on emission reducing options for engines in the oil and gas sector, as we've identified elsewhere, other facilities in this and other sectors also contribute to regional haze, such as the San Juan Generating Station, and we maintain an interest in seeing the New Mexico haze SIP control pollution from those sources as well.

In response to your request for more information regarding selective catalytic reduction (SCR) for lean burn engines, we have attached an expert report prepared by Victoria Stamper and Megan Williams. As the report describes in detail, SCR is a feasible and cost-effective pollution control option. However, rather than require SCR, we urge NMED to require operators to replace gas-fueled engines with electric motors wherever feasible. To that end, the agency must establish clear and specific criteria for determining "infeasibility." Electrification is ultimately the best option for reducing or eliminating emissions of NO_x (and all other air pollutants from gas-fired engines), thereby better reducing visibility and public health harming emissions while helping New Mexico achieve its climate goals. Electrification can also be highly cost-effective. State and federal regulations establish the authority for NMED to require electrification of gas engines or replacement or set near-zero NO_x emissions limits, as detailed below. Where electrification is not feasible, SCR provides a feasible and cost-effective alternative.

I. <u>Benefits of Electrification</u>

Gas-fired engines used in oil and gas development contribute significantly to NO_x and other air pollution in New Mexico. Electric engines, by contrast, eliminate NO_x and other pollutants, decrease noise levels, and are easier to maintain. Compared to gas-fired engines, electric engines also result in fewer upset events at wells – events that can release large quantities of pollutants, including volatile organic compounds ("VOCs") and methane, a powerful greenhouse gas with 86 times the 20-year global warming potential of CO_2.[1] Mandatory electrification would significantly reduce methane emissions and waste, ozone, and haze, leading to improved air quality and thus improved visibility and health throughout New Mexico. It would also help New Mexico achieve its climate and energy goals, including but not limited to those articulated in Governor Michelle Lujan Grisham's January 2019 Executive Order

[1] *See* Vicki Stamper & Megan Williams, Nat'l Parks Conservation Ass'n, *Oil & Gas Sector Reasonable Progress Four-Factor Analysis of Controls For Five Source Categories* 57 (2020) [hereinafter Stamper & Williams, *Oil and Gas Four-Factor Analysis of Controls*].

2019-003, "Executive Order on Addressing Climate Change and Energy Waste Prevention."[2] Mandatory electrification would also complement and reinforce NMED's (and EMNRD's) ongoing efforts to reduce ozone and methane emissions through the Ozone Attainment Initiative (OAI) and Methane rulemakings, respectively.

Electrification can also be highly cost-effective. In 2001, the California Air Resources Board (CARB) found that electrification of units between 50 and 500 hp can control NOx pollution at a cost of about $900 to $1,100 per ton of NOx reduced.[3] CARB further concluded that for units between 500 and 1,000 hp the installed costs of electrification and internal combustion engines are about the same, and that below 500 hp the installed costs of electrification are lower than the installed costs of comparable internal combustion engines.[4] Given the significant advances in technology during the past 20 years, electrification is likely even more cost effective today.

II. Legal Authority for Electrification

Under state and federal law, NMED has the authority to mandate the electrification of engines used in oil and gas development, and/or to set NO_x emissions limitations near zero to favor electrification. Requiring SCR is also well within the scope of the state's regulatory authority. However, in order to create a SIP that will best meet state and federal clean air objectives, electrification should be required.

A. State Law

Broadly, New Mexico's Air Quality Control Act, Chapter 74, Article 2, NMSA 1978 ("Air Quality Control Act") requires the New Mexico Environmental Improvement Board (Board) to "prevent or abate air pollution."[5] The Board shall "adopt, promulgate, publish, amend and repeal rules and standards consistent with the Air Quality Control Act to attain and maintain national ambient air quality standards and prevent or abate air pollution," and "adopt a plan for the regulation, control, prevention or abatement of air pollution, recognizing the differences, needs, requirements and conditions within the geographic area of the environmental improvement board's jurisdiction . . ."[6]

Further, the Environmental Improvement Board may take action inclusive of "rules to protect visibility in mandatory class I areas to prevent significant deterioration of air quality and to achieve national ambient air quality standards in nonattainment areas . . . "[7] A rule requiring electrification of oil and gas engines would further NMED's duty to prevent or abate air pollution, including via adoption, promulgation, publication, or amendment of rules and adoption of a plan for the regulation, control,

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[2] Executive Order 2019-003, "Executive Order on Addressing Climate Change and Energy Waste Prevention," (January 29, 2019), *Available at* https://www.governor.state.nm.us/wp-content/uploads/2019/01/EO_2019-003.pdf

[3] *Id.* at 41-42. CARB's conservative cost estimate, which is in 1999 dollars, assumed only 2,000 hours of operation each year and a 10-year, rather than a 30-year, life of the equipment. *Id.* at 42; *See generally Id.* at 41-46.

[4] Cal. Air Res. Bd., *Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines*, at V-5 (2001), https://ww3.arb.ca.gov/ractbarc/rb-iceall.pdf.

[5] Air Quality Control Act, 74-2-5 (A) NMSA 1978 (emphasis added).

[6] Air Quality Control Act, 74-2-5 (B)(1) and (B)(2) NMSA 1978.

[7] Air Quality Control Act, 74-2-5 (C)(1) and (C)(2) NMSA 1978.

prevention or abatement of air pollution. Mandating electrification would also further NMED's duty to adopt rules to protect visibility in mandatory Class I areas to prevent significant deterioration of air quality.

Electrification would also account for the "character and degree of injury to or interference with health, welfare, visibility, and property" caused by engines and "the public interest, including the social and economic value of the sources *and subjects* of air contaminants."[8] (*Emphasis added*). Electrification of gas-fired RICE engines would eliminate 100% of NOx and other emissions.

These emissions degrade air resources in and around class 1 airsheds, which negatively impacts the health of nearby communities, and undercuts the economic benefits of the national parks and wilderness areas which comprise these airsheds. For example, NOx emissions from increased energy activity in the Permian Basin have led to noted degradation of visibility for park visitors, and repeated instances of 24-hour non-attainment of ozone near Carlsbad Caverns National Park, and deposition of NOx in the area's fragile ecosystem threatens its unique flora and fauna. Damage to the park's resources would greatly harm the area's economy; a 2019 National Park Service report shows that 466,000 visitors to Carlsbad Caverns National Park in 2018 spent $30.2 million in communities near the park. That spending supported 405 jobs in the local area and had a cumulative benefit to the local economy of $34 million.[9]

Given its technical feasibility and cost effectiveness, electrification also ensures that NMED considers measures through the lens of its duty to consider "technical practicability and economic reasonableness of reducing or eliminating air contaminants from the sources involved and previous experience with equipment and methods available to control the air contaminants involved."[10]

Finally, electrification of oil and gas drilling and other operations serves to fulfill cross-cutting initiatives by the state to address various air pollutant emissions. Electrification is mentioned as a pollution control technology for many methane emissions sources. The MAP Technical Report notes that due to the resulting elimination of criteria pollutants, HAPs, and methane, "In some situations, oil and gas operators determine that electrified compression is a viable and preferred technology in place of natural gas fired engines or turbines."(MAP Technical Report p. 99). Further discussion of recommendations for putting electrification into practice can be found in the following sections of the MAP Technical Report, to aid in establishing paths forward for achievement of air quality goals:

- Section 10.4, outlining utility co-op incentives to expand service territories in the pursuit of providing well sites with electricity;
- Section 10.8, recommends the establishment of interagency coordination to more efficiently and speedily develop electrical oilfield infrastructure in cooperation with utilities to manage distributed generation, increasing the ability of operators to cost effectively adopt electrification;
- Section 10.15, recommends that the state allow temporary gen set power on a site, in case of delays in getting line power to the site, mitigating methane as well as haze-causing pollutant emissions.

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[8] Air Quality Control Act, 74-2-5 (E)(1) and (E)(2) NMSA 1978.

[9] U.S. National Park Service (NPS), "Tourism to Carlsbad Caverns National Park Creates $34 Million in Economic Benefits" (May 24, 2019), *Available at* https://www.nps.gov/cave/learn/news/tourism-creates-34-million-in-economic-benefits.htm

[10] Air Quality Control Act, 74-2-5 (E)(3) NMSA 1978.

We thus emphasize the need for interagency coordination among waste and pollution regulators and electric utility regulators, including the Public Regulation Commission, to facilitate policies to most effectively enable electrification.

B. Federal Law

In developing the state's regional haze plan under the federal Clean Air Act, the state has discretion to set NOx emissions limitations that favor electrification. In developing a regional haze SIP, a state must include reasonable progress requirements based on consideration of four factors, including the energy and non-air quality environmental impacts of compliance.[11] The state must also develop a long-term strategy for regional haze that includes enforceable emissions limitations, and emissions reduction measures necessary to make reasonable progress.[12] As explained above, and discussed in further detail in the March 6, 2020 report on Reasonable Progress Controls for the Oil and Gas Sector, electrification of engines used in oil and gas development is a cost-effective pollution control strategy with an array of environmental, climate, and public health co-benefits. The cost effectiveness of this NOx pollution control strategy supports requiring electrification of oil and gas engines and establishing a corresponding very low (near-zero) NOx limit for this source category.

Setting low NO_x emissions limits and considering technology that reduces or eliminates emissions, such as electrification, for oil and gas engines is well within the scope of regional haze analysis and SIP development, and is consistent with the Clean Air Act, and regulatory requirements for reasonable progress outlined in 40 C.F.R. § 51.308(d)(1). Regional haze SIPs must contain "emissions limits, schedules of compliance, and other measures as may be necessary to make reasonable progress toward the national goal." 42 U.S.C. § 7491 (b)(2). In determining what emissions reductions measures are needed to make reasonable progress, states must consider four factors: the cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts of compliance, and remaining useful life of any potentially affected sources. 40 C.F.R. § 51.308(d)(1)(i)(A). Near-zero NO_x emissions limitations would be well within these parameters–and indeed would have positive energy and non-air quality environmental impacts.

Requiring the replacement of gas-fired engines with electric motors would serve as a reasonable progress measure applicable to a source type and would not constitute "redesigning the source" or otherwise fall outside the allowable scope of the state's regional haze planning authority. These engines assume a variety of applications, including gas compression, pumping, and power generation and the functionality of the source is undisturbed irrespective of whether it is subject to more or less stringent emission limitations. The difference is in the scale of pollution emitted or avoided as determined by the type of control strategy or technology employed to achieve an emission limit in order to help achieve a variety of benefits in the public interest, here motivated by requirements to achieve reasonable progress towards natural visibility conditions.

In looking at other regional haze requirements, the BART Guidelines allow states to "establish design, equipment, work practice or other operational standards when limitations on measurement technologies make emission standards infeasible." 40 C.F.R. Appendix Y to Part 51, Section I (E)(3). More broadly, Clean Air Act programs and analyses such as BACT, and PSD afford considerable flexibility

[11] *See* 40 C.F.R. § 51.308(d)(1)(i)(A), (f)(2)(i), (f)(3)(i).
[12] *See* 40 C.F.R. § 51.308 (f)(2)(i), (f)(3)(i).

to regulators in determining the range and type of pollution reduction practices or control strategies for states to consider as well. As the U.S. EPA Environmental Appeals Board has stated:

> "Permit issuers generally have broad discretion in conducting BACT determinations, but they are strongly discouraged from categorizing emissions control options as "impermissible redesign" without first taking the requisite "hard look" at the project. ***To skip this step might result in their "paving an automatic BACT off-ramp" that "frustrates congressional will" and may constitute a reversible abuse of discretion***. *In re N. Mich. Univ.*, 14 E.A.D. 283, 302 (EAB 2009); *accord La Paloma*, slip op. at 26, 16 E.A.D. ___. "[13] (Emphasis added).

Nothing in the Clean Air Act, applicable regulations or guidance, prohibits emissions limitations that reflect the reductions achievable through electrification. NMED should thus exercise its authority under state and federal law to require that oil and gas operators electrify oil and gas engines by either mandating electrification or establishing a NOx emission limit near 0 g/hp-hr. Doing so will expedite New Mexico's progress toward attaining natural visibility in national parks and other Class I areas, help the state in its Ozone Attainment Initiative and efforts to reduce methane emissions and waste, and help New Mexico achieve its climate goals, including but not limited to those outlined in Governor Lujan Grisham's Executive Order 2019-003.

III. <u>SCR as a Feasible, Cost Effective Option Where Electrification is Infeasible</u>

While replacement of gas-fired engines in oil and gas development with electric motors is our preferred pollution control measure, we recognize that there may be instances in which electrification is not feasible. If electrification is demonstrated to be infeasible in a given case, e.g., when there is no reasonable access or reasonable opportunity to create access to a power grid, we recommend that NMED require selective catalytic reduction (SCR), a cost-effective and practicable option as described in the attached Expert Report and the March 6, 2020 report on Reasonable Progress Controls for the Oil and Gas Sector. Some highlights from the Expert Report include:

- SCR has been an effective, feasible technology applied to lean burn engines for nearly four decades.

- Multiple emissions tests conducted in California for several lean burn engines with SCR showed 84% to 87% NO_x reductions, even after several years of operation.

- While space constraints can be a concern for SCR retrofits, there are several proven ways to address this issue. For example, SCR systems can be installed in place of existing exhaust mufflers on the roof of buildings.

- Given the relatively advanced age of most lean-burn engines for which NMED has requested reasonable progress analysis (with many manufactured before the Clean Air Act was enacted in 1970), NMED should also consider replacing these engines with new engines with

[13] *See, e.g., In Re: Arizona Public Service Company Ocotillo Power Plant,* 17 EAD 323, 336-37 (E.P.A. Sept. 1, 2016) *(citing In re N. Mich. Univ.,* 14 E.A.D. 283, 302 (EAB 2009*); In re La Paloma,* 16 EAD 267, 289 (EAB 2014)). ("Each such determination, like each BACT analysis itself, requires a case-by-case analysis and is highly fact- and circumstance-specific. *La Paloma,* slip op. at 26, 16 E.A.D. at ___ (citing CAA § 169(3), 42 U.S.C. § 7479(3)) (defining "BACT" as a "case-by-case" determination); GHG Guidance at 26.").

state-of-the-art low NO_x emission control technology, or, as advocated throughout this letter, replacing them with electric engines that would eliminate NO_x emissions (and other air pollutant emissions) altogether.

IV. Conclusion

Electrification is a feasible, cost-effective pollution control technology which NMED has the authority to require in its regional haze SIP. In addition to helping NMED achieve reasonable progress towards national visibility goals as required by the Clean Air Act, electrification has several co-benefits for climate, health, and ongoing regulatory and policy initiatives in New Mexico. Thus, we request that NMED require emission limitations as reasonable progress for gas-fueled engines reflective of replacement with electric-motors, with limitations reflective of SCR instead as an option when electrification is not feasible.

Thank you again for your continued engagement with the public during the regional haze SIP development process, even amidst the difficult conditions of the COVID-19 pandemic, and for your consideration of the recommendations and information in this letter and attached Expert Report. Please do not hesitate to contact us with any questions or concerns, or to discuss the attached SCR analysis or electrification further.

Sincerely,

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Review of Claims Made by New Mexico Oil and Gas Companies
Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines

May 21, 2020

By

Victoria Stamper and Megan Williams

We have reviewed most of the claims raised by New Mexico oil and gas companies regarding applicability of selective catalytic reduction (SCR) to lean burn engines and have conducted additional research beyond what was provided in our March 6, 2020 report. We are providing some additional information to address some of the issues raised in the New Mexico company submittals with respect to SCR on lean burn engines. Specifically, claims were raised that SCR has not been proven for lean burn engines or specifically for two-stroke engines.

As discussed in our March 6, 2020 report on Reasonable Progress Controls for the Oil and Gas Sector, SCR has been applied to lean burn engines since the 1980's. EPA's 1993 Alternative Control Techniques Document for RICE said they had found "23 SCR installations with lean-burn SI engines [] in the United States from information provided by catalyst vendors, in addition to over 40 overseas installations."[1]

EPA's 1993 Alternative Control Techniques (ACT) Document for RICE had emissions test information for 16 SCR applications at lean burn engines at 9 installations in California, including for Cooper-Bessemer engines.[2] Specifically, EPA provided performance data from a California vendor for an SCR application on a 660 hp Cooper-Bessemer Engine (Model GMV-6) that achieved 80% NOx control and data for two Cooper-Bessemer engines Model GMV-8 that also achieved 80% control of NOx.[3] Notably, the GMV-8 engines were using a load-following ammonia control, which is best suited for engines operated at variable load. In addition, EPA's 1993 ACT Document also provided emissions test data from California's Ventura County Air Pollution Control District for SCR used with lean burn RICE, including test data from 1987-1990 for two Cooper-Bessemer engines (Models GMV and GMV-8) and several Clark engines (Engine Models HRA-6 and HRA-32).[4] Note, some of the engines were no longer operating at the time of EPA's 1993 ACT Document due to being electrified as a result of Southern California Edison's incentive program.[5]

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[1]March 6, 2020 Report at 34; EPA 1993 Alternative Control Techniques Document for RICE.
[2] U.S. EPA, Alternative Control Techniques Document – NOx Emissions from Stationary Reciprocating Internal Combustion Engines, EPA -453/R-93-032, July 1993, *available at:* https://www3.epa.gov/airquality/ctg_act/199307_nox_epa453_r-93-032_internal_combustion_engines.pdf ("EPA 1993 ACT Document") at 5-61 to 5-62
[3] *Id.* at Table 5-8 at 5-62.
[4] *Id.*, Appendix A at A-16 (Table A-5).
[5]*Id.*

In September 2000, EPA issued an updated report on Stationary RICE controls.[6] Based on that EPA report, we said in our March 2020 report that "…while diesel engines are the most prevalent applications of SCR at RICE units, SCR has also been applied at lean-burn spark-ignition engines fired with natural gas, including at natural gas pipeline compressor stations."[7] The SCR installations at the time of EPA's 1993 and 2000 reports were mostly if not all from California. Several California air districts had adopted NOx limits for existing RICE that required SCR on lean burn engines particularly if low emissions combustion systems would not have allowed the unit to meet the applicable limits (or were not as cost effective as SCR), as was demonstrated in the cost reports relied on or cited in our report.[8]

In EPA's 2000 Update, it discusses one facility that operated SCR on a lean burn engine for 12 years (from 1984-1996). According to EPA, "[t]he SCR system met or exceeded the guaranteed level of NOx control (70 percent), allowing the facility to meet the applicable emission limit."[9] Indeed, emissions testing from 1993 of this lean-burn SCR retrofit as well as another lean-burn engine the company operated with SCR – eight to nine years after SCR installation – showed the SCR achieving between 84 to 87% NOx reduction.[10] This data certainly seems indicative of SCR working to significantly reduce NOx at lean-burn engines. The EPA 2000 Update identifies costs with operating the SCR, including the costs of continuous emissions monitoring systems (CEMs), cost of anhydrous ammonia, and cost of catalyst replacement.[11] The EPA 2000 Update also said that the facility found operation and maintenance required additional work not normally required for an engine.[12] These are cost issues with the control, but SCR is still a technically feasible control. Twelve years of operational data on a lean-burn engine with the engine continuing to meet high levels of NOx control even after several years of operation clearly show that SCR is a demonstrated technology for lean-burn engines. According to EPA, the company subsequently – twelve years after installation of SCR – replaced the engine with Low Emissions Combustion (LEC)-equipped engines.[13] Thus, there is no current emissions data for the engine reflective of SCR.

The EPA 2000 Update also refers to emissions test data from the Ventura County Air Pollution Control District (VCAPCD) for 7 lean burn engines with SCR, ranging in size from 291 bhp to 800 bhp.[14] The average percent NOx reduction from the test data was 84%.[15] Again, this data indicates that SCR is technically feasible for lean-burn engines. Instead, this data shows that SCR works to significantly reduce NOx from lean-burn engines. This test data was conducted from 1986 to 1993.[16] After 1993, EPA noted that the VCAPCD database did not include test data for lean-burn engines with SCR, but EPA also noted that several engines were replaced with electric motors and that a 1998 paper indicated that

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[6] *See* U.S. EPA, Stationary Reciprocating Internal Combustion Engines Updated Information on NOx Emissions and Control Techniques, EPA-457/R-00-001, September 2000, *available at:* https://nepis.epa.gov/Exe/ZyPDF.cgi/P100V343.PDF?Dockey=P100V343.PDF ("EPA 2000 Update").
[7] March 6, 2020 Report at 35; EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-13.
[8] March 6, 2020 Report at 36-40.
[9] EPA 2000 Update at 4-14.
[10] *Id.*
[11] *Id.*
[12] *Id.*
[13] *Id.*
[14] *Id.*
[15] *Id.*
[16] *Id.*

VCAPCD's more stringent NOx limits adopted in 1993 were intended to encourage electrification of engines.[17]

EPA's 2000 Update also cited to information from vendors of SCR systems, indicating that SCRs on lean-burn engines since 1993 have been designed to achieve 80-95% control and citing to a design outlet NOx emissions levels for three lean-burn engines at one natural gas pipeline compressor facility of less than 30 ppmv. Again, that information indicates that SCR continued to be applied to lean-burn engines, including those used at compressor stations.

Also, EPA's 2000 Update discussed test summary data for three 3,130 bhp 4-stroke lean-burn engines equipped with SCR systems that were believed to be urea-based.[18] These engines were at a liquid fuel pipeline pumping station and operated at variable loads and variable speeds, "depending on the quantity, pressure, and density of the fuel being pumped."[19] EPA stated, "[t]he SCR system utilizes a feedforward system based on engine load and speed and on exhaust temperature." According to EPA, the engines achieved their required NOx emission limit (15 ppmv or about 0.2 g/bhp-hr) during all testing with NOx emission ranging between 0.11 grams per brake horsepower per hour (g/bhp-hr) and 0.21 g/bhp-hr.[20]

EPA's 2000 Update also discussed a plot of CEM data over a 10 minute period from a heavy-duty diesel truck engine equipped with a feedforward urea SCR system. According to EPA:

> During this period, the engine varied from a speed of about 700 rotations per minute (rpm) at idle to about 2,300 rpm, with load varying concurrently from nearly 0 foot-pounds (ft-lbs) to about 800 ft-lbs. Inlet NOX concentrations varied closely with load, ranging from a less than 10 ppmv up to over 150 ppmv. Outlet NOX concentrations remained relatively stable, varying from nearly 0 ppmv up to about 20 ppmv.[21]

While this CEM data is from a diesel engine, this data shows how a feedforward urea system can address issues of variable NOx emissions due to variable loads and engines speeds – regardless of whether coming from a diesel-fired or gas-fired engine.

EPA further stated:

> Vendors of SCR systems indicate that the feedforward controls on modern systems provide for excellent NOX control in load-following applications. One representative indicated that the advance in technology has been driven by the interest of diesel engine manufacturers, working with catalyst vendors, in developing urea SCR for on-road vehicles. Such vehicles exhibit varying load by nature. [Fn omitted]. Another source also stressed that the PEMS feedforward system, with optional CEMS feedback system, has been advanced by a strong research and development effort. This vendor

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[17] *Id.* at 4-15.
[18] EPA 2000 Update at 4-15.
[19] *Id.*
[20] *Id.*
[21] *Id.*

> has supplied such SCR systems for a variety of applications, including stationary IC engines, ship engines, railroad engines, and diesel truck engines. [Fn omitted].[22]

In a more recent example of SCR being applied to two-stroke lean-burn engines, such engines at a power generating facility in Utah were successfully retrofit with SCR systems. Specifically, a Power Engineering article from 2006 discusses the retrofit of SCR systems along with catalytic convertors at lean burn engines at a Springville Utilities power station in Utah.[23] These engines burned 90% natural gas and 10% diesel. The article discusses one of the main problems using a catalyst on a two-stroke engine is the poisoning of the catalyst by the engine lubricant and states that the catalyst selected (manufactured by Miratech Corporation) was "designed to be durable and overcomes this problem."[24] While these units are used to generate electricity, this is still a relevant example of SCR being applied to two-stroke lean-burn engines. It is not known what the age of the two-stroke lean-burn engines that were retrofitted with SCR at the Springville Utilities power station in Utah. It appears that the power station being referred to is the Whitehead Power Plant, which (according to the Springville City website) was built in 1985 and was powered by Enterprise R4-V16 engines and EMD 645 engines.[25]

As another more recent example, a demonstration project was conducted at the Orange County Sanitation District's Central Power Generating Station, which is fueled by 95% landfill digester gas and 5% natural gas.[26] A demonstration project done at one Cooper Bessemer LSBV-12-SGC (a 3,471 hp lean-burn engine that drives a 2.5 MW generator) found that 78-86% NOx reduction could be achieved.[27]

SCR was also installed at the Bio Energy Washington landfill-gas dual-fuel power plant at which there are 18 dual-fuel 350 kW engine generators fueled by landfill gas and diesel.[28] This is a power plant located at the Cedar Hills gas processing facility in Washington.[29] An interesting fact about this application is that each SCR plus oxidation catalyst system treats the exhaust from 6 engines. Thus, only three SCR systems were required for 18 engines,[30] an approach that could greatly reduce the capital cost of NOx reduction and also address space constraints for SCR installation.

While we realize that space constraints can be an issue for SCR retrofits, this is something that has been dealt with on numerous instances for SCR retrofits for numerous industrial facilities. A concern about lack of space for an SCR should not be a reason to discount an SCR as not technically feasible without consultations with vendors about options for SCR locations. For example, the Manufacturers of

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[22] *Id.* at 4-15 to 4-16.
[23] *See* "Emissions Control for Huge Two-Stroke Engines: It Can Work, Power Engineering, 2/3/06, available at https://www.power-eng.com/2006/02/03/emissions-control-for-huge-two-stroke-engines-it-can-work/#gref.
[24] *Id.*
[25] *See* https://www.springville.org/power/about/.
[26] *See* Institute of Clean Air Companies, NJ DEP/ICAC Technology Seminar, November 24, 2014, at Slide 26.
[27] *Id*. at Slide 31. *See also* Johnson Matthey Application fact sheet 1304 for Orange County Sanitation District, available at https://www.jmsec.com/references/application-fact-sheets/?L=0.
[28] *See* Institute of Clean Air Companies, NJ DEP/ICAC Technology Seminar, November 24, 2014, at Slide 24.
[29] *Id.* at 21.
[30] *Id.* at Slide 24.

Emission Controls Association (MECA) describes situations where SCR systems have been installed in place of the existing exhaust muffler on the roof of buildings housing a lean-burn engine.[31]

In terms of SCR applications on lean-burn engines in the EPA's RACT/BACT/LAER Clearinghouse, we found several examples. The table below lists those RBLC entries that we found, which was not necessarily an exhaustive search.

EPA RACT/BACT/LAER Clearinghouse Entries for Lean-burn Engines with SCR

RBLC ID Number	Company Name	Permit Date	Weblink
MI-0440	MICHIGAN STATE UNIVERSITY	5/22/2019	https://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.PollutantInfo&Facility_ID=28704&Process_ID=113037&Pollutant_ID=149&Per_Control_Equipment_Id=166066
CA-1240	GOLD COAST PACKING	3/17/2017	https://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.PollutantInfo&Facility_ID=28389&Process_ID=111763&Pollutant_ID=149&Per_Control_Equipment_Id=161706
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	3/31/2016	https://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.ProcessInfo&facility_id=28279&PROCESS_ID=111490
KS-0035	TRADEWIND ENERGY, INC.	1/24/2014	https://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.ProcessInfo&facility_id=28362&PROCESS_ID=111715 and https://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.PollutantInfo&Facility_ID=28362&Process_ID=111715&Pollutant_ID=149&Per_Control_Equipment_Id=161501
TX-0692	SOUTH TEXAS ELECTRIC COOPERATIVE, INC.	12/20/2013	https://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.PollutantInfo&Facility_ID=27823&Process_ID=109804&Pollutant_ID=149&Per_Control_Equipment_Id=156478
TX-0663	ETC TEXAS PIPELINE, LTD.	5/25/2012	https://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.PollutantInfo&Facility_ID=27718&Process_ID=109572&Pollutant_ID=149&Per_Control_Equipment_Id=155758
PA-0303	NATL FUEL GAS SUPPLY CORP	2/2/2012	https://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.ProcessInfo&facility_id=28009&PROCESS_ID=110380
CA-0959	NEO CALIFORNIA POWER	4/9/2001	https://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.PollutantInfo&Facility_ID=25194&Process_ID=99462&Pollutant_ID=149&Per_Control_Equipment_Id=125492

In addition to these specific examples of SCR applications, a 2011 report from the state of Delaware highlights many examples of commercially available retrofit NOx controls for engines and turbines used in gas compressor prime mover service, including SCR.[32] Several of the SCR systems were specifically

[31] Written Statement of the Manufacturers of Emission Controls Association on the San Joaquin Valley Unified Air Pollution Control District's Proposed Amendments to Rule 4702 (August 2, 2011), *available at:* http://www.meca.org/galleries/files/MECA_SJV_Rule_4702_testimony_080211.pdf.

[32] *See* Background Information Oil and Gas Sector Significant Sources of NOx Emissions, *available online at*: https://fossil.energy.gov/ng_regulation/sites/default/files/programs/gasregulation/authorizations/2011/applications/exhibits_11-161-LNG/36_DE_Nox.pdf.

advertised as being applicable to lean-burn natural gas fired engines utilized for gas compression (e.g., CleanAir Systems, Johnson Matthey, Miratech Corporation, Clean Air Power, etc.).[33] We highlighted some of these vendors in our March 2020 report, and pointed out how catalysts have been developed to operate over a wide range of temperatures.[34] Some of the information provided in the Delaware report included specific announcements for orders and installations at lean-burn natural gas compressor engines and / or at natural gas midstream sources (e.g., installations on large lean-burn natural gas compressor engines at gas storage sites in Texas and Mississippi).[35] The Delaware report discusses some of the SCR systems being formulated for operation at a wide range of temperatures, allowing for NOx control over a wide range of engine operation.[36] More generally, the Delaware Report dispels several technical issues specific to two-stroke lean-burn SCR retrofits, including the availability of: (1) modern controls and communication technologies to help overcome potential issues with remotely manned units; (2) catalysts that are effective over wide temperature ranges that are reflective of a wider range in engine operating loads (noting that SCR systems "have been installed on EGUs that start and stop on a daily basis, and change loads across a wider range while on line to balance electric generation to electric demand"); and (3) the ability to closely regulate fuel, air, and reagent flow to ensure proper SCR function over a broad range of operating condition.[37]

Targa's February 2020 Regional Haze Four-Factor Analysis Addendum stated the following in response to NMED's request for the "historical precedent that installation of SACR on two-stroke lean-burn (@SLB) engines can result in significant technical complications, require deration of engines, and unreliable operation post-retrofit:"

> Selective catalytic reduction technology has not been applied successfully to 2SLB engines. After researching SCR controls on 2SLB engines, the EPA document titled "Technical Issues Related to the Potential Use of Selective Catalytic Reduction (SCR) to Reduce NOx Emissions from Natural Gas-Fired Lean Burn Engines" is the only document found with information on the application of SCR's on 2SLB engines. This documentation shows that many units did not perform properly after SCR was installed. Targa was unable to find any historical installation of SCR on 2SLB engines in the RLBC tables. The only proven technology to control NOX for 2SLB engines is Clean Burn Technology. This is also the technology recommended by the engine control vendor to control NOX for the units at Targa's three gas plants.[38]

It must first be pointed out that the document that Targa referred to as an "EPA document" is a 1998 document prepared for the Gas Research Institute. Second, the document referred to is now twenty-two years old. We provided one example of SCR being successfully retrofit to lean-burn engines at the Springville Utilities Power Station in Utah. Further, the 2011 Delaware reported discussed above highlights several SCR vendors with a focus on lean-burn engines, including two-stroke lean-burn

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[33] *Id.* at PDF pp. 29-32.
[34] March 6, 2020 Report at 34. *See also* https://matthey.com/en/products-and-services/emission-control-technologies/mobile-emissionscontrol/selective-catalytic-reaction, https://www.miratechcorp.com/products/cbl/, and http://intermountainelectronics.com/uploads/media/Media_633929646982817973.pdf.
[35] *Id.* at PDF p. 31.
[36] *Id.* at PDF p. 30. (Johnson Matthey).
[37] *Id.* at PDF p. 35.
[38] February 2020 Regional Haze Four-Factor Analysis Addendum, Targa Midstream Services LLC, at pdf page 7.

engines. With respect to the RLBC not identifying any two-stroke engines using SCR, the RBLC entries that we found showing SCR being required on lean-burn engines generally do not specify whether the engines are two-stroke or four-stroke.

In summary, the information provided herein shows that SCR is considered a demonstrated technology that can be applied to lean-burn engines. The information presented above shows examples of SCR being applied to Cooper-Bessemer and Clark lean-burn engines. including two-stroke lean-burn engines. The reports cited above show application of SCR to natural gas-fired lean-burn engines used in the oil and gas industry starting in the 1980's to 1990's, and the RBLC data show SCR being required on lean-burn engines in more recent years including those used in the oil and gas industry. While application of SCR to lean-burn engines used in the oil and gas industry may not be commonplace, one cannot say it has not been required or implemented on lean-burn natural gas-fired engines used in the natural gas industry. Further, the fact that SCR has been retrofit and installed on lean-burn engines used in electricity production is still relevant information. Because most of those lean-burn engines operate as peaking or peak shaving power plants, the lean-burn engine load will vary greatly, more in line with how a compressor engine would operate. Thus, the use of SCR at natural gas-fired power generating lean-burn engines provides further support of the feasibility of SCR for lean-burn engines used in the oil and gas industry.

We understand that the age of the lean-burn engines for which NMED has requested reasonable progress analyses are quite old. Our review based on age of engines reported in permits for the New Mexico facilities shows that the age range of the lean-burn engines for which New Mexico has targeted for reasonable progress controls ranges from 39 years to as high as 72 years. Most of the engines were manufactured before the 1970 Clean Air Act was enacted. It appears that in most cases, the companies have not proposed any NOx controls for these older lean-burn engines in their reasonable progress analyses, claiming that SCR is not feasible and that Clean Burn (i.e., low emissions combustions) is too costly to retrofit. Given the age of these engines, consideration should be given to the control of replacing the engines with new engines with state-of-the-art low NOx emission control, or replacing the engines with electric engines powered off the grid which would reduce emissions of NOx (and all other pollutants from the engines) down to zero. As discussed in our March 6, 2020 Report, replacement of engines with electric motors can be quite cost effective.[39]

[39] March 6, 2020 Report at 41-46.

July 10, 2020

Attn: Sandra Ely, Michael Baca, Mark Jones, and Kerwin Singleton

New Mexico Environment Department
Harold L. Runnels Building
1190 St. Francis Drive, Suite N4050
Santa Fe, New Mexico 87505
Re: Comments responding to 4-factor analysis submittals from identified oil & gas operators

Dear Ms. Ely, Mr. Baca, Mr. Jones, and Mr. Singleton,

We applaud the New Mexico Environment Department for welcoming public input and engagement throughout the development of its Regional Haze State Implementation Plan (SIP). We encourage the agency to require robust measures in its forthcoming SIP that will result in clearer skies and better air quality in our state and region's Class 1 Airsheds and communities.

We submit the attached expert comments on the four-factor analyses submitted by oil and gas facilities in New Mexico prepared by consultants Megan Williams and Vicki Stamper.

The report identifies numerous errors in operators' 4-factor analyses, including overestimation of interest rate and underestimation of life of controls, high capital estimates, failure to annualize costs in some cases, failure to provide emissions data that reflect a reasonable estimate of current and future actual operations, failure to document sources of emissions data and/or claims made regarding feasibility of controls, and failure to analyze available control options, including electrification.

We value NMED's inclusion of the 20 oil and gas facilities in the state's four-factor list and encourage the state to consider the contents of the attached report. We also request NMED assess control options applicable to source categories within the oil and gas sector from facilities that were excluded from its four-factor list. We urge the state to pursue electrification across the sector and in the alternative ask the state to apply category-wide requirements that would result in effective reductions in visibility-impairing pollution.[1]

We re-emphasize our request that NMED require electrification of engines as an overarching control option. As detailed in our May 22, 2020 cover letter accompanying a report on SCR feasibility at Lean Burn engines, electrification is ultimately the best option for reducing or eliminating emissions of NOx and all other air pollutants from gas-fired engines, thereby better reducing visibility and public health-harming emissions while helping New Mexico achieve its climate goals.

NPCA, Western Environmental Law Center, and other allies across the state are committed to working with the agency, operators, and utilities to identify solutions to overcome spatial and regulatory questions regarding oilfield electrification. We believe a harmonized framework is within reach to aggregate emissions and load, and generate power as a collective instead of operating as a dispersed set of points. Acknowledging the structural questions of oilfield electrification, we urge NMED to move forward on a parallel track with emission-limiting requirements necessitating electrification. Public lands and our communities deserve no less than a forward-looking regional haze plan that will effectively curb existing burdens and mitigate future impacts to air quality.

[1] We refer NMED back to the March 2020 NCPA Oil and Gas Four-Factor Report for consideration of effective control options for oil and gas source categories.

Notwithstanding the above, we offer the following summary takeaways from the attached assessment.

Summary of Effective Controls for Emission Units at New Mexico Oil and Gas Facilities

Combustion Turbines: Based on the revised and additional cost analyses provided in the report, SCR is cost effective for most combustion turbines at the New Mexico Gas Plants evaluated, with the few exceptions potentially being units that limit operating hours (for example, Kutz Canyon Unit 4 appears not to operate much based on its reported NOx emissions in 2016, should limited operations be enforceable, SCR would not be considered cost effective). While several operators summarily dismissed SCR as a feasible pollution control, they failed to support their claims, failing to provide site details or vendor proposals for claims of site constraints or other claimed retrofit difficulties. Although the attached report did not evaluate SCR cost effectiveness for the turbines at Kutz Canyon, Indian Basin or South Carlsbad due to lack of the needed inputs to utilize EPA's SCR cost spreadsheet, based on the other SCR cost analyses that are provided in the report for several similar combustion turbines, SCR should be considered the most cost effective, and most effective in terms of NOx reductions, for all combustion turbines operating more than ~1,000 hours per year. Beyond superior emission-reducing capabilities, SCR is also preferable as water use is not an adverse impact from use of the technology. We further note that SCR combined with SoLoNOx or other dry low-NOx combustion techniques may be the more fitting control option at some units because it would achieve the greatest reduction in NOx emissions.

Lean Burn Engines: As found in NPCA's March 2020 Oil and Gas Four-Factor Report, LEC has been required for retrofit controls—and has been deemed cost effective—for Lean Burn RICE units of a wide size range (e.g., down to 50 hp).[1] In many cases when considering LEC as a potential control, operators failed to specify achievable emission rates, often greatly underestimating the reductions that might be achieved and therefore underestimating the cost effectiveness of the technology. In the accompanying comments on four-factor analyses for oil and gas facilities in New Mexico, LEC is shown to be cost effective for most engines except for those that consistently operate a limited number of hours per year. However, it's important to note that, for some engines, operation may be limited in one year but that may not hold true for the same unit for other years. For example, Targa indicated that "[w]ith regards to the engine usage, Targa attempts to use its engines uniformly but this does not mean equally on a calendar year basis."[2] So, when looking at the cost effectiveness of LEC control for RICE it's important to consider how the engine will be used, on average, over the life of controls rather than just looking at one year that may or may not be representative of that engine's usage in other years. Generally, LEC is cost effective for the specific engine models analyzed operating over 1,000 per year and can achieve 80–90% NOx reduction and reduce NOx emission rates to 2 g/hp-hr and lower. In addition, SCR is shown to be cost effective for Lean Burn engines at the two plants that evaluated SCR for such engines (Roswell Compressor Station No. 9 and Jal No. 3 Gas Plant). Based on those cost analyses as revised in the attached report, SCR should also be considered a cost effective control, with the capability to achieve 90% NOx reduction and reduce NOx emission rates to 1 g/hp-hr.

Rich Burn Engines: As with Lean Burn RICE, control of NOx emissions from Rich Burn RICE has been widely required for retrofit controls—and deemed exceedingly cost effective—for a wide range of units (e.g., down to 50 hp). Specifically, the Rich Burn RICE units at Targa's Saunders Gas Plant NSCR was shown to be extremely cost effective—at under $300 per ton of NOx reduced—based on Targa's own analysis. No other New Mexico facilities submitted cost analyses for Rich Burn RICE but, given that NSCR is often extraordinarily cost effective, NMED should assess the Rich Burn units at the facilities that submitted four-factor analyses, even if those units have NOx emissions that fall below NMED's original cutoffs of 10 lb/hr or 5 tpy; cumulatively, control of NOx emissions from these emissions units using NSCR would be a very cost effective way to achieve additional, meaningful NOx reductions.

Amine Units/Acid Gas Flaring: For amine units and associated acid gas flares at gas sweetening plants, an acid gas injection well with a backup electric acid gas compressor is the minimum level of control of SO2

that should be required. In fact, NMED has required this suite of controls in some settlement agreements, according to information provided in the Targa Eunice Gas Plant and Monument Gas Plant four-factor analyses. For those locations at which an acid gas injection well may not work effectively, then a sulfur recovery unit (SRU) along with an incinerator *and* acid gas scrubber should be used to most effectively control SO2 emissions. Alternatively, a facility could employ both an acid gas injection well and a sulfur recovery unit, as is implemented at the Jal No. 3 amine unit, although improvements should be made at that facility, such as adding an acid gas scrubber to the SRU or routing the acid gas stream from the SRU to the acid gas injection well. Any maintenance or upset that requires the flaring of the acid gas stream from an amine unit can be a significant source of SO2 emissions and thus redundancy of controls is key for reducing/eliminating SO2 emissions associated with amine units at gas sweetening plants.

In a 2018 presentation from the Air Resources Division of the National Parks Service, entitled "Source Attribution Using Volatile Organic Compound Measurements to Assess Air Quality Impacts at Five National Parks in the Western US," data is shown confirming that Carlsbad is impacted by VOCs from oil and gas activity in the Permian. This further warrants the implementation of the strongest suites of controls at amine units and associated gas flares.

NOx is a visibility-impairing pollutant of interest: We urge the agency to dispel the claim made by several operators that SO_2, not NOx, is the contaminant of interest for visibility impairment in various Class 1 Airsheds. Both pollutants contribute to visibility impairment and emissions of nitrogen oxides must be mitigated to make reasonable progress toward the national goal of restoring natural air quality conditions. Some operators claim that NOx emissions from these pieces of equipment are inconsequential for regional haze purposes, while numerous federal agencies and groups have maintained that reducing NOx is necessary for best reducing visibility-reducing haze.

Colorado State's IMPROVE website makes available a Particulate Matter and Haze Composition Browser (available at http://vista.cira.colostate.edu/Improve/pm-and-haze-composition/), in which there is a map of all Class I areas, with associated 2018 data of PM composition by day. The recent data found in this IMPROVE resource reinforces the importance of controlling NOx in improving visibility in Class 1 airsheds impacted by oil and gas – particularly as this industrial activity has been accelerating greatly in the past several years. As shown in the data for 2018 for Carlsbad Caverns (Figure 1), nitrates are a significant contributor to PM in the winter months.

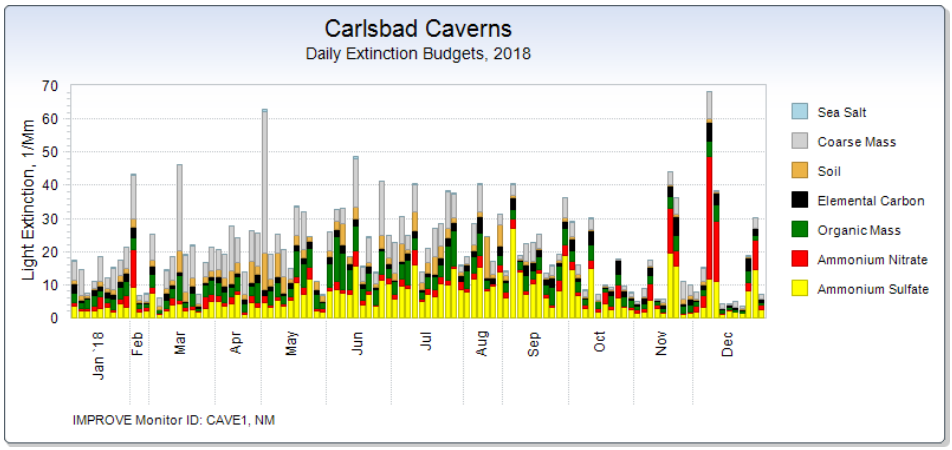

Figure 1.

Moreover, EPA's 2019 Regional Haze Guidance specifies that a state may use a number of screening tools and New Mexico's Q/d approach is a recognized screening methodology that reflects emissions of both SO2 and NOx.

Additional facilities that warrant reduction requirements: The agency's 10 lb/hr and 5 tpy criteria leaves out a wide array of facilities and equipment which contribute significantly to regional haze. In some cases, the agency did not require four-factor analysis for all units at a plant that had PTE greater than these thresholds (such as Units 7 and 8 at Kutz Canyon Gas Plant) - even though the company submitted other four-factor analyses for other units at the same facility.

NPCA has analyzed facilities not identified by NMED as being required to submit four-factor analyses (Figure 2). We have detailed the findings below, including the number of like sources and emissions and emission rate equivalents. In all, we assessed 62 additional facilities, with NOx emissions greater than 50 tpy. The NOx emissions from these 62 additional facilities total 10,711 tons per year according to the 2019 emissions NMED data. Within these 62 facilities, are 209 Lean Burn RICE units (Figure 3):

- 134 Lean Burn RICE units have NOx limits that equate to values greater than 1.0 gr/hp-hr.
- 69 Lean Burn RICE units have NOx limits that equate to values greater than 1.5 gr/hp-hr.
- 17 Lean Burn RICE units have NOx limits that equate to values greater than 2.0 gr/hp-hr.

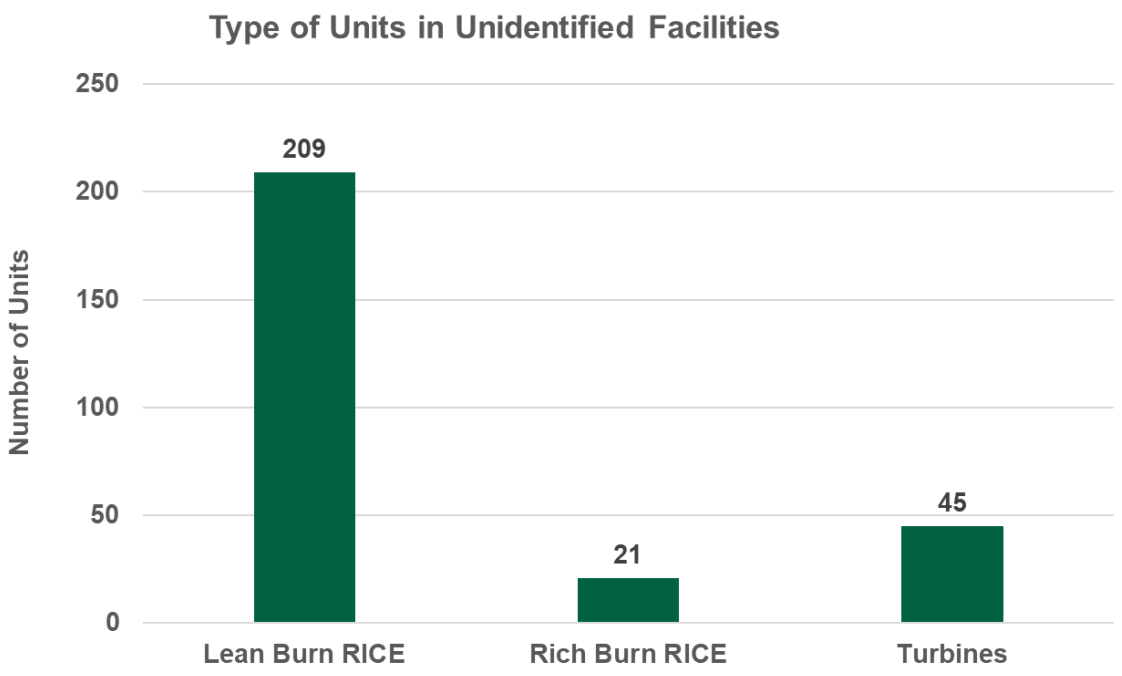

Figure 2.

As discussed above, emission reduction controls such as LEC and SCR are cost effective controls and can be used at these units to achieve NOx limits that equate to 0.15 to 2 g/hp-hr. with a NOx removal efficiency ranging from 87% to 95%. NPCA recommends NMED require a four-factor analysis of any Lean Burn RICE with equivalent NOx emission rates greater than 1.0 gr/hp-hr.

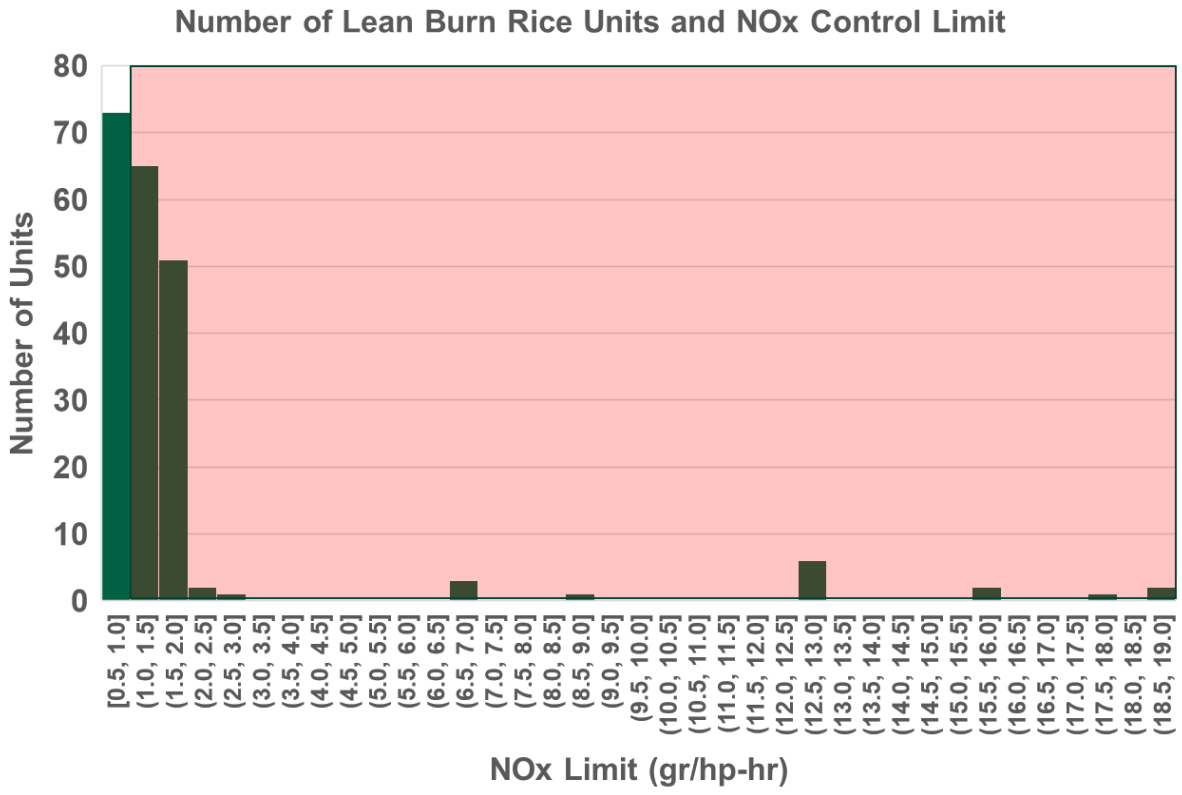

Figure 3.

In addition, we identified 21 Rich Burn RICE units at the 62 facilities not selected by NMED for a four-factor analysis. Of these Rich Burn RICE units, 17 have NOx limits that equate to 1.0 gr/hp-hr (Figure 4). Controlled NOx emission rates from 0.3 to 1.6 g/hp-hr. can be achieved using NSCR with a NOx removal efficiency ranging from 90% to 98%. Given the extremely favorable cost effectiveness of NSCR, NPCA recommends NMED require a four-factor analysis for any Rich Burn RICE with equivalent NOx emission rates greater than 1.0 gr/hp-hr.

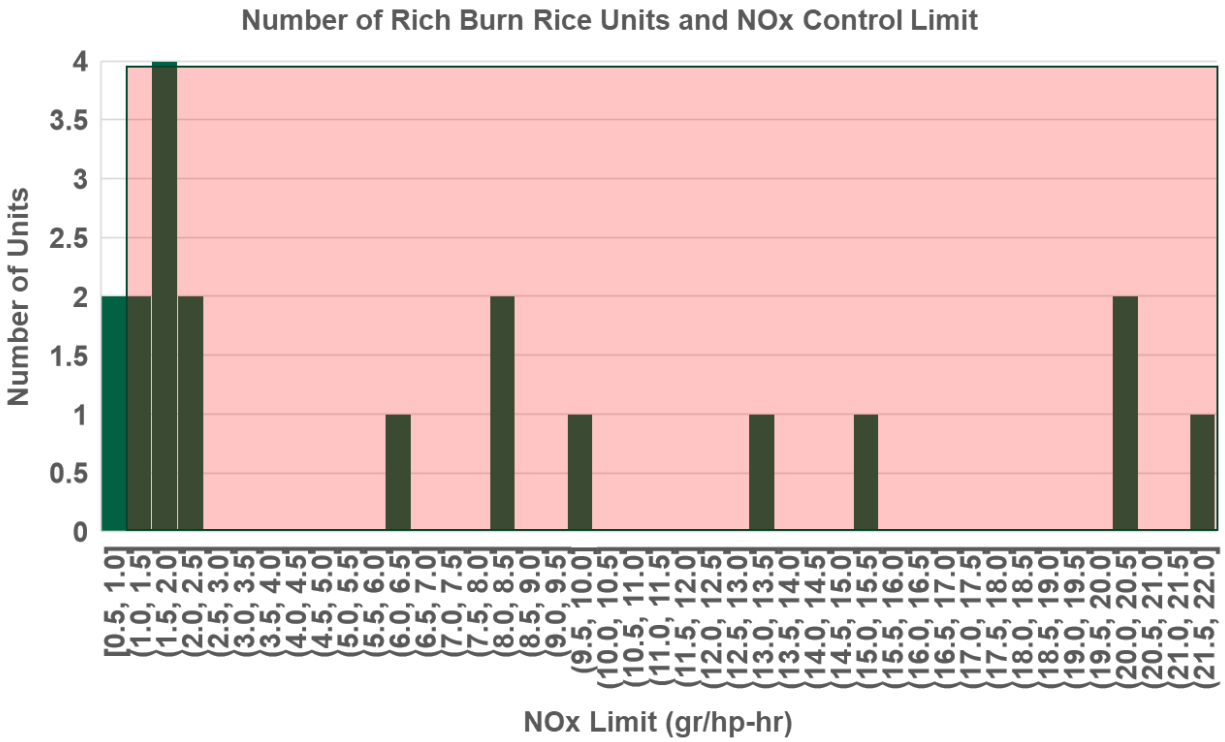

Figure 4.

Lastly, NPCA identified 45 turbines at compressor stations not selected for a four-factor analysis by NMED. Of them, 43 turbines have NOx limits higher than 15 parts per million (ppm) (~0.06 lb/MMBtu) (Figure 5), which reflects a controlled NOx emissions rate achievable with Dry Low NOx Combustors (DLNC) such as SoLoNOx or with SCR. NPCA recommends NMED require a four-factor analysis of these 45 gas turbines with equivalent NOx emission rates greater than 15 ppm.

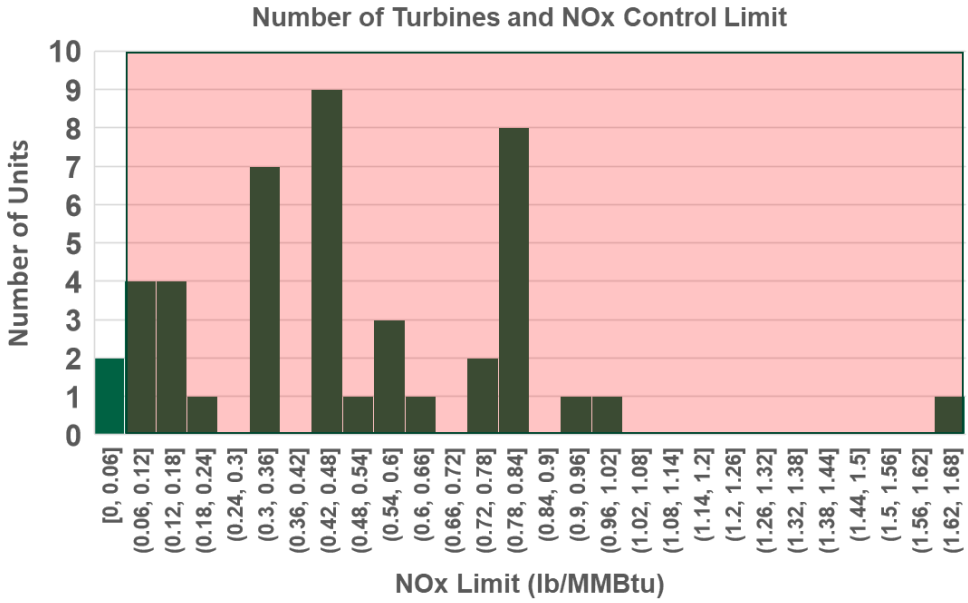

Figure 5.

In closing, we greatly appreciate the opportunity to work with New Mexico Environment Department, and welcome any questions and discussion regarding the attached comments and next steps to ensure the New Mexico Regional Haze Plan results in significant improvements to the visibility at our treasured Class I landscapes and across our communities.

Thank you,

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Assessment of Cost Effectiveness Analyses for Controls Evaluated Four – Factor Analyses for Oil and Gas Facilities For the New Mexico Environment Department's Regional Haze Plan for the Second Implementation Period

July 2, 2020

Prepared for National Parks Conservation Organization

Prepared by:

Vicki Stamper & Megan Williams

Executive Summary

In a March 2020 report on reasonable progress controls for several sources in the oil and gas sector, the authors provided general four-factor analyses of regional haze pollution control options for five source categories in the oil and gas industry, including natural gas-fired engines, combustion turbines, boilers, heaters, diesel-fired engines, and flaring and incineration.[1] That report identified regional haze pollution control options that are cost-effective and have been required by state and local air pollution control agencies through adaptation of emission limitations requiring retrofit of pollution controls for most of these source categories. For example, the report showed that, for natural gas-fired reciprocating internal combustion engines (RICE), cost effective controls include replacing engines with electric compressors, use of nonselective catalytic reduction (NSCR) at rich burn RICE, and use of low emissions combustion (LEC) or selective catalytic reduction (SCR) at lean burn RICE.[2] For natural gas-fired combustion turbines, the report found that the installation of dry low NOx combustion or the use of SCR (or in combination with dry low NOx combustion) is cost effective.[3] And for natural gas-fired heaters and boilers, the use of ultra-low NOx burners and/or SCR were found to be cost effective.[4] We refer the New Mexico Environment Department (NMED) to the March 2020 NCPA Oil and Gas Four-Factor Report for consideration in deciding the pollution controls to require of the New Mexico oil and gas sources for which NMED requested four-factor analyses.

In this document, we provide more specific comments on the cost of controls in the four-factor analyses submitted by oil and gas companies to NMED. The document is organized to provide comments on the facilities' four-factor analyses in order of magnitude of each facilities' "Q/d" value based on 2014 emissions. In the last sections of this document, we provide comments on two additional sources for which NMED did not request four-factor analyses but for which NPCA requested that NMED evaluate based on the facilities' Q/d—the Corona Compressor Station and the Empire Abo Gas Plant. And in the very last section, we provide comments on the four-factor analyses and control options for SO_2 emissions from amine units and flaring including startup, shutdown, malfunction emissions. Specifically, this report provides comments on the company cost analyses and/or provides cost analyses on the listed emission units at the following gas compressor stations and gas processing plants in New Mexico.

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[1] *See* National Parks Conservation Association (NPCA) Report Entitled Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, and Flaring and Incineration, prepared by Vicki Stamper and Megan Williams, March 6, 2020 {hereinafter referred to as March 2020 NPCA Oil and Gas Four-Factor Report"].

[2] *Id.* at 10-57.

[3] *Id.* at 61-90.

[4] *Id.* at 116-146.

Emission Units and Facilities Evaluated in this Report

Plant	Units	Type of Emission Unit
Enterprise Chaco Gas Plant	17, 18, 35, 36, & 37	Gas Turbines
	12, 13, 14	2SLB RICE
DCP Eunice Gas Plant	17A, 18A, & 19A, 25A & 26A	Gas Turbines
	31	Amine Unit/SRU incinerator
IACX Bitter Lake Compressor Station	C-891 & C-893	2SLB RICE
Targa Eunice Gas Plant	C-01 thru C-07, & C-09 thru C-12	2SLB RICE
	B-01 & B-02	Gas-fired Boiler
Targa Monument Gas Plant	C-01, C-02, C-04 through C-06, & C-28	2SLB RICE
	AM-01/F-03	Amine Unit/Flare
Targa Saunders Gas Plant	C-01 thru C-09	2SLB RICE
	G-01 thru G-03	4SRB RICE
	AM-10/I-01	Amine Unit/Incinerator
Artesia Gas Plant		Flares
Harvest Four Corners Kutz Canyon Gas Plant	1 thru 6, 19, & 20	Gas Turbines
	16, 17, & 18	2SLB RICE
EPNG Pecos River Compressor	A-01, A-02, & A-03	Gas Turbines
DCP Linam Ranch Gas Plant	29, 30, 31, & 32B	Gas Turbines
	6 thru 11	2SLB RICE
ETC Texas Pipeline Jal No. 3 Gas Plant	4A & 5A	2SLB RICE
Davis Gas Processing Denton Gas Plant	007	Amine Unit/Flare
El Paso Natural Gas Co Washington Ranch Storage Facility	A-01 & B-01	2SLB RICE
Enterprise Blanco C&D Compressor	T-C01, T-C02, & T-D01	Gas Turbines
Harvest Pipeline San Juan Gas Plant	1 thru 7	Gas Turbines
Oxy USA WTP Indian Basin Gas Plant	ES-06/07, 08/09, & 10/11	Gas Turbines
		Amine Units
Enterprise South Carlsbad Compressor	1 & 2	Gas Turbines
El Paso Natural Gas Co Blanco Compressor Station A	A1 thru A14	2SLB RICE
Transwestern Roswell Compressor Station No. 9	903 & 904	4SLB RICE
Transwestern Mountainair Compressor	701, 702, & 703	4SLB RICE
Transwestern Corona Compressor Station	801 & 802, 821 & 822	2SLB RICE
	821 & 822	4SRB RICE
Empire Abo Gas Plant		Sulfur Recovery/Incinerator

RICE Notes: 2SLB: Two-Stroke Lean Burn; 4SLB: Four-Stroke Lean-Burn; 4SRB: Four-Stroke Rich-Burn

In general, the facilities' four-factor analyses are addressed in the order given in the above table, except that amine units and acid gas flares are addressed collectively in Section XXIII at the end of this report.

One overarching control option that NMED should give serious consideration to for lean burn RICE is the electrification of these engines. As was demonstrated in the March 2020 NCPA Oil and Gas Four-Factor Report, electrification of RICE units used for gas compression can be very cost effective just considering the NOx removal benefits, in the range of $1,200-$2,800/ton of NOx removed.[5] And several other pollution control benefits would occur with electrification of engines. From the regional haze perspective, replacing fossil fuel-fired RICE with electric engines would also reduce other visibility-impairing pollutants formed by the engines including volatile organic compounds (VOCs) and, for diesel-fired engines, particulate matter and sulfur dioxide (SO_2). Further, there would be reduced emissions of VOCs from compressor blowdowns. In addition, electric engines would require less maintenance time and have fewer upsets, which would not only reduce high NOx emissions that occur due to startups, shutdowns, and malfunctions, but would also reduce flaring of gas during compressor engine downtime which will reduce VOCs, NOx and, if the gas is sour gas, SO_2. And, of course, the additional significant co-benefit of the reduction in fossil fuel-firing and the reduction in upsets/less maintenance is that greenhouse gases will be greatly reduced. As stated in the NPCA Oil and Gas Report, replacing five RICE engines at a compressor station with electric compressors could eliminate approximately 16,000,000 cubic feet per year of fugitive methane emissions, which along with the greenhouse gas reductions from not burning natural gas in the engines would reflect a reduction of about 12,000 tons per year of carbon dioxide (CO_2) equivalent emissions.[6]

While the analysis of the costs to electrify units in the March 2020 NCPA Oil and Gas Four-Factor Report did not include any costs to upgrade electricity to a facility if needed, there are options that NMED should consider to reduce costs of power upgrades. For example, if more than one facility is located nearby each other, the facilities could partner to bring and/or upgrade electricity to the facilities. In a review of permits for midstream oil and gas facilities on NMED's Emissions Analysis Tool website,[7] there are at least five natural gas processing plants with electric engines in the New Mexico portion of the Permian Basin: 1) Targa -Eunice Gas Processing Plant, 2) Transwestern - Roswell Compressor No. 9, 3) Occidental- South Hobbs Reinjection Compression Facility, 4) DCP – Zia II Gas Plant, and 5) Durango Midstream – Maljammer Gas Plant. NMED should explore whether there are options for these plants to either electrify more engines and/or partner with nearby facilities to enable any necessary electric utility upgrades to electrify currently gas-fired engines. In the northwest part of New Mexico, there are three facilities that are co-located and are actually considered to be one source for Title V purposes despite having different owners: Blanco A Compressor Station,

[5] *Id.* at 44.
[6] *Id.* at 45-46.
[7] https://eatool.air.net.env.nm.gov/aqbeatool/.

Blanco C&D Compressor Station, and San Juan Gas Plant.[8] These facilities are about 1 mile from the city of Bloomfield, so they are not very remote. There are several lean burn RICE that could be replaced with electric engines at these facilities. Given the significant regional haze benefits that could be realized with electrification of engines, NMED should consider these and other options to facilitate implementation of this highly effective control measure.

With respect to other, albeit less effective than electrification control measures that should be considered cost effective for the emission units in the above table, the revised and supplemental cost effectiveness analyses provided herein support the findings of the March 2020 NCPA Oil and Gas Four-Factor Report. First, nonselective catalytic reduction (NSCR) is extremely cost effective for rich burn RICE. Given how cost effective NSCR is and how effective the control is for reducing NOx emissions, NMED should request analyses for all rich burn RICE at the facilities that submitted four-factor analyses, even if those units have NOx emissions that fall below NMED's emission thresholds of 10 pounds per hour (lb/hr) or 5 tons per year (tpy). Installation of NSCR could be a very cost effective way to achieve additional, meaningful NOx reductions at midstream facilities in New Mexico.

With respect to lean burn RICE, low emissions combustion (LEC) and, where evaluated, selective catalytic reduction (SCR), is generally cost effective for lean burn RICE that are operated greater than 500-1,000 hours per year. While several of the four-factor submittals to NMED had very high cost effectiveness values for LEC, those cost effectiveness analyses were often improperly inflated for the reasons discussed herein, including the assumption of low baseline emissions by focusing on a single year of baseline emissions. A single year of operational data of a lean burn engine used in a gas processing facility may not reflect how the unit will operate on average over its lifetime. For example, Targa, indicated that "[w]ith regards to the engine usage, Targa attempts to use its engines uniformly but this does not mean equally on a calendar year basis."[9] If an engine operates less than 1,000 hours per year—consistently, from year to year—LEC may not be cost effective. However, generally, LEC is cost effective for the specific engine models analyzed and can achieve 80–90% NOx reduction and reduce NOx emission rates to 2 g/hp-hr and lower. In addition, SCR is also shown below to be cost effective for lean burn engines at the two plants that evaluated SCR for such engines (Roswell Compressor Station No. 9 and Jal No. 3 Gas Plant). Based on those cost analyses provided herein, SCR should also be considered a cost effective control for lean burn engines, with the capability to achieve 90% NOx reduction and NOx emission rates of 1 g/hp-hr. With respect to claims made about whether SCR can be effectively used at lean burn engines, we refer NMED to the May 21, 2020 report "Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines" that NPCA provided to NMED via a May 22, 2020 letter.

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[8] *See* 2/16/2015 Title V Operating Permit No. P048-R3 for Blanco Compressor Station A at 3.

[9] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 6.

For gas-fired combustion turbines, combustion controls and SCR have been required as best available control technology for new gas-fired turbines that power compressors at compressor stations.[10] In addition, combustion controls and SCR have been retrofit to numerous combustion turbines in numerous instances, primarily at electric utility combustion turbines. In revised and supplemental cost analyses presented herein, SCR is shown to be cost effective for most of the combustion turbine evaluated. While several companies made claims of space constraints and retrofit difficulty for SCR, the fact that SCR has been retrofit to numerous existing combustion turbines, coal-fired boilers, refineries, and other emissions sources that were not originally designed with space for SCR indicates that retrofit difficulties can and have been overcome. NMED should not allow a company to ignore evaluation of SCR based on purported retrofit difficulty claims without getting a vendor analysis of retrofit options for this highly effective control. The revised and supplemental cost effectiveness analyses provided herein show that SCR is cost effective for most of the combustion turbines evaluated in the New Mexico oil and gas facility four-factor analyses, unless the turbine has consistently low levels of operation and a low level of baseline emissions (in which case NMED should consider capping operations or emissions as a regional haze control).

For amine units and associated acid gas incineration or flaring, an acid gas injection well with, at the minimum, a backup electric acid gas compressor is the minimum level of control of SO2 that should be required. In fact, NMED has required this suite of controls in some settlement agreements, according to information provided in the Targa Eunice Gas Plant and Monument Gas Plant four-factor analyses. For those locations at which an acid gas injection well may not work effectively, then a sulfur recovery unit along with an incinerator and acid gas scrubber should be used to most effectively control SO2 emissions. Any maintenance or upset that requires the flaring of the acid gas stream from an amine unit can be a significant source of SO2 emissions and thus redundancy of controls is key for reducing/eliminating SO2 emissions associated with amine units at gas sweetening plants.

Below, we provide comments on the cost analyses in the company submittals made to NMED and provide revised and/or supplement cost analyses for the emission units analyzed.

[10] *See*, e.g., January 9, 2019 Registration No. 21599 for Buckingham Compressor Station, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.

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I. Enterprise Field Services Chaco Gas Plant

The Enterprise Field Services (Enterprise) Chaco Gas Plant is a natural gas processing plant. NMED has described the plant process as follows:

> The function of the facility is to receive field natural gas, process the gas through removal of water, then extraction/separation of natural gas liquids (NGL) through a cryogenic process. NGL recovered are then treated to remove carbon dioxide and hydrogen sulfide. Recovered NGL is delivered to a pipeline for transport to fractionation facilities downstream. The facility compresses/pumps residue and sales natural gas for distribution through mainline natural gas pipelines.

3/1/2019 Statement of Basis for Title V Permit Significant Modification (Permit Nos. 1555-M6 (revisions through M6R2) and P116-R2M1 at 1.

According to the permit, the plant includes several 2-stroke and 4-stroke lean-burn RICE, several natural gas-fired turbines, a diesel generator, flares, and a heater.[11] In Enterprise's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- General Electric (GE) Frame 5 Turbines: Units 17 and 18
- Solar Mars T-15000 Turbines: Units 35, 36, and 37
- Clark TLA-10 2SLB SI-RICE Engines: Units 12, 13, and 14.[12]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tons per year (tpy), which is the criteria established by NMED to identify sources subject to four-factor analyses.[13] The following provides a review of the company's four-factor analyses.

A. Interest Rate Used in Cost Analyses.

Enterprise used an 8.38% interest rate in the cost analyses for all the controls evaluated in its 4-factor analyses.[14] This is an unreasonably high interest rate for cost effectiveness analyses. EPA's Control Cost Manual indicates that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[15] The current bank prime rate is 3.25%.[16] The highest

[11] Title V Operating Permit P116-R2M1 for Chaco Natural Gas Processing Plant at A6 to A8.
[12] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 1-2.
[13] *Id.*
[14] *Id.* at Section 8.0 Supporting Documentation.
[15] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at:

the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[17] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. However, in a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[18] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. Enterprise's use of an 8.38% interest rate is unreasonably high and overstates the cost effectiveness of pollution controls evaluated in the four-factor analyses.

B. GE Frame 5 Turbines: Units 17 and 18.

Units 17 and 18 at the Chaco Gas Plant are 19,500 horsepower natural gas-fired turbines that were constructed in 1970 and 1971.[19] The units each have a NOx emissions limit of 78.5 lb/hr and 344 tpy.[20] For these units, Enterprise identified water or steam injection as viable combustion controls for NOx but claimed that dry low NOx combustors were not available for retrofit to these types of gas turbines.[21] Enterprise claimed that SCR installation was not possible for these gas turbines, due to the size estimates of the SCR.[22] Presumably, Enterprise is claiming issues of retrofit difficulty. There is no question that SCR is technically feasible for natural gas-fired combustion turbines, including those used at compressor stations.

1. Evaluation of Baseline NOx Emissions.

According to the company's cost analysis for water/steam injection, Unit 17 has an actual NOx emission rate of 29.15 lb/hr (54.7 ppm) and Unit 18 has an actual NOx emission rate of 29.15 lb/hr (48.7 ppm) based on 2016 stack test data.[23] These actual emission rates are much lower than the units' 78.5 lb/hr allowable NOx emission rates, so either the 2016 stack test data was not performed while the engines were operating at maximum capacity, or the allowable NOx

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https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.

[16] https://www.federalreserve.gov/releases/h15/.

[17] https://fred.stlouisfed.org/series/DPRIME.

[18] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.

[19] Title V Operating Permit P116-R2M1 for Chaco Natural Gas Processing Plant at A6 to A8.

[20] *Id.* at A10.

[21] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant, Part 3 of zipped file available on NMED's Emission Analysis Tool, at pdf page 11.

[22] *Id.* at 2-4.

[23] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 82- to 8-3.

emission rates have been set unreasonably high. NMED should present information on the 2016 stack test data so the circumstances of the stack tests can be reviewed. In addition, NMED and Enterprise should review other stack tests for these units to ensure that the actual emission rates can be considered to truly reflect actual emissions over the lifetime of the controls being evaluated. For example, in the November 2007 Title V renewal application for the Chaco Gas Plant, the actual emission test results were listed for Unit 17 as 49.22 lb/hr when the unit was operating at 83% load and was listed for Unit 18 as 69.8 lb/hr when the unit was operated at 89% load.[24] In addition, test data from 1995 was also included in the November 2007 permit application which shows Unit 17 with a NOx emission rate of 78.7 ppm @15% oxygen (O_2) and 90.6 ppm @ 15% O_2 and Unit 18 with a NOx emission rate of 93.4 ppm @ 15% O_2 and 109.5 ppm @15% O_2.[25] Clearly, these actual emission rates from Enterprise's 2007 Title V permit application are significantly higher than the 29.15 lb/hr (48.7-54.7 ppm) NOx emission rates that the company's four-factor cost effectiveness analysis is based upon. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on an estimate of emissions expected in 2028 pursuant to EPA's regional haze guidance for the second implementation period.[26]

2. Evaluation of Water Injection and Steam Injection for NOx Control

As a result of assuming what appears to be unreasonably low NOx emission rates for current emissions from the GE Frame 5 turbines, Enterprise also assumed an unreasonably low level of NOx reduction in its cost effectiveness analysis of water injection and steam injection. Specifically, Enterprise only assumed a 15% NOx reduction from water or steam injection.[27] While Enterprise cites EPA's AP-42 emission factor documentation for the 15% control with water or steam injection, EPA's AP-42 states that such controls can achieve 60% or higher NOx removal.[28] EPA's 1993 Alternative Control Techniques Document (ACT) for NOx emissions from Stationary Gas Turbines, cited in EPA's AP-42 emission factor documentation, states that NOx rates in the range of 25 to 42 ppmv can be achieved with water or steam injection as gas-fired combustion turbines.[29] For the Frame 5 turbines installed at the Chaco Gas Plant which, based on the 1978 year of manufacture indicated in the Title V permit, were presumably Model MS5001P,[30] EPA's 1993 Gas Turbine ACT listed the uncontrolled NOx emissions as 142 ppmv, dry, at 15% O_2.[31] Thus, a reduction to 25-42 ppm with water or steam injection would equate

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[24] November 2007 Title V Permit Application for Chaco Gas Plant, Part 3 at pdf page 11.
[25] *Id.* at pdf pages 14 and 15.
[26] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation period, at 29.
[27] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 2-3.
[28] EPA, AP-42 Emission Factor Documentation, at 3.1-6.
[29] *See* EPA. Alternative Control Techniques Document – NOx Emissions form Stationary Gas Turbines, EPA-453/R-93-007, January 1993, at 2-5 [hereinafter EPA 1993 Gas Turbine ACT].
[30] *See* https://www.ccj-online.com/3q-2012/special-report-the-venerable-frame-5-gas-turbine/.
[31] *See* EPA. Alternative Control Techniques Document – NOx Emissions form Stationary Gas Turbines, EPA-453/R-93-007, January 1993, at 2-3.

to a 70% to 82% reduction in NOx emissions with water or steam injection from EPA's listed uncontrolled NOx rate of 142 ppmv. If the uncontrolled emissions of Units 17 and 18 are truly in the range of 48.7 to 54.7 ppm as indicated in Enterprise's 4-Factor analyses (assuming this is parts per million by volume at 15% oxygen, which NMED should confirm) and that is a reasonable projection of NOx emission rates into 2028 despite prior emission tests that were much higher than these levels, it seems very likely that the water or steam injection could reduce NOx down to at least 25 ppmv @ 15% O_2, which would be a reduction in emissions of 56% at Unit 17 and of 50.7% at Unit 18. Thus, NMED must require that Enterprise evaluate water or steam injection for Units 17 and 18 assuming a 25 ppmv @ 15% O_2 NOx rate could be achieved.

With respect to the life assumed of water or steam injection, Enterprise only assumed a 15-year life of these controls.[32] Enterprise did not provide any justification for assuming such a short life of water or steam injection. As discussed in NPCA's March 2020 report, the life of water or steam injection should be the life of the combustion turbines. In NPCA's March 2020 report, we assumed a 25-year life of water or steam injection.[33]

In terms of Enterprise's costs for water injection or steam injection, the company's capital costs seem very high for the size turbines, based on a comparison to the 1999 Department of Energy (DOE) report entitled "Cost Analyses of NOx Control Alternatives for Stationary Gas Turbines," which is cited in several EPA and State documents on the costs of NOx controls at gas turbines.[34] In that 1999 DOE report, the costs of water or steam injection for a slightly larger gas turbine, a GE LM2500 turbine which is of 22.7 megawatt capacity or about 30,400 hp, the capital cost in 1999 dollars of water injection was estimated to be $1,083,175.[35] Although EPA's Control Cost Manual advises against escalating costs more than five years because it can lead to inaccuracies in price estimation,[36] just using the Chemical Engineering Plant Cost Indices between 1999 and 2018, the DOE's 1999 costs of water injection for a larger GE LM2500 gas turbine would increase to $1.67 million.[37] Using a different cost index specific to oil refineries, the Nelson-Farrar index, the 1999 costs of water injection increase from $1.0 million to $1.88 million as of 2016 (the most recent annual Nelson-Farrer cost index found online).[38] Yet,

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[32] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 6-1.
[33] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 64.
[34] Bill Major, ONSITE SYCOM Energy Corporation, and Bill Powers, Powers Engineering, Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines, prepared for U.S. Department of Energy, November 5, 1999, available at: https://www.energy.gov/sites/prod/files/2013/11/f4/gas_turbines_nox_cost_analysis.pdf [hereinafter "1999 DOE Report"].
[35] *Id.*, Appendix A at A-4.
[36] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.
[37] Based on multiplying the 1999 cost estimate for water injection from the 1999 DOE report by the ratio of the CEPCI indices for 2018 to 1999 (603.1/390.6).
[38] Based on multiplying the 1999 cost estimate for water injection from the 1999 DOE report by the ratio of Nelson-Farrar indices for 2016 to 1999 (2598.7/1497.2).

Enterprise's capital cost estimate for water injection at Units 17 and 18 was $6.6 million, more than three times the escalated capital costs from the 1999 DOE report based on either the CEPCI index or the Nelson-Farrar index. Thus, Enterprise's capital cost estimate of water injection for a smaller capacity gas turbine at Units 17 and 18 seems very high. Further, the inspection and operating costs of water injection, which Enterprise stated would be $1,238,327 per year,[39] are not explained or documented and seem unreasonably high. NMED must request more details and support for these cost estimates of water injection and steam injection at Units 17 and 18.

We addressed just some of these issues to revise Enterprise's cost effectiveness analyses to reflect 1) a 4.7% interest rate (instead of 8.38%), 2) a 25-year life of water or steam injection (instead of an assumed 15-year life), 3) a controlled NOx rate with water or steam injection of 25 ppmvd at 15% O_2, and 4) revising Enterprise's baseline emissions to reflect EPA's NOx rate for uncontrolled GE Frame 5 gas turbines of 142 ppmvd[40] and a controlled NOx rate of 42 ppmvd. With the revisions listed in items 1 through 3 above, Enterprise's cost effectiveness of water or steam injection reduction from approximately $107,000 to $149,000/ton of NOx removed to $24,500- $38,692/ton, and it is important to note that no changes were made to Enterprise's own seemingly high estimates for capital and operating costs of water or steam injection. Revising Enterprise's cost estimates to use EPA's uncontrolled NOx rate for the turbine models of 142 ppmvd and a controlled NOx rate of 42 ppmvd with water or steam injection (the least stringent NOx emission rate that EPA indicates can be met with the control), reduces cost effectiveness of these controls to $7,300-$10,500/ton. Again, these revisions do not reflect any changes to Enterprise's seemingly high capital and operating costs for water or steam injection.

In its identification of energy and non-air quality environmental impacts of compliance, Enterprise did not list water use as an adverse environmental impact, but it is an issue to be concerned with for water injection.[41] That is why dry low NOx combustion, if available (which Enterprise claims is not available for the Unit 17 and 18 turbine models) or SCR are more preferable choices for NOx control from gas-fired turbines in New Mexico.

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[39] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 8-2 to 8-3.
[40] *See* EPA. Alternative Control Techniques Document – NOx Emissions form Stationary Gas Turbines, EPA-453/R-93-007, January 1993, at 2-3.
[41] *See* March 6, 2020 NPCA Oil and Gas Four-Factor Report at 67-68.

3. Evaluation of SCR for Units 17 and 18 Gas Turbines.

Enterprise did not evaluate SCR for the Units 17 and 18 gas turbines, stating that it was "not possible to install these units at the Chaco facility" due to "the amount of buffer space needed to maintain accessibility to equipment and to avoid compromising worker safety."[42] While the facility and gas turbines may not have been originally designed to have space to accommodate SCR, that is typically the case with most SCR retrofits. As such, there have been numerous SCR retrofits installations at various industrial facilities that have had to overcome space constraints. For example, for many large coal-fired power plants, SCR reactors have been elevated above the air preheaters. Indeed, a report about SCR retrofits at GE LM2500 turbines at Chevron's Eastridge Cogeneration plant in California showed that some significant changes to the facility had to be made to accommodate SCR, including cutting the duct between economizers and moving the stack and one economizer onto new foundations to make way for the SCR reactor.[43] Thus, before NMED accepts a very brief claim of retrofit difficulty of SCR at any emissions unit being evaluated for reasonable progress controls, it is imperative that NMED ask Enterprise for a site plan and photos that show whatever space constraints are being claimed, and that NMED asks Enterprise to consult with SCR vendors for options for SCR installation at the gas turbines of Units 17 and 18. For Unit 18, a schematic of the unit provided in the 2007 Title V permit application shows an oil heat recovery unit labeled as "out of commission."[44] Perhaps extracting that heat recovery unit out of the unit would enable for the relocation of the stack and space for the SCR. Unit 17 is also shown as being equipped with a heat recovery unit[45] and it is not clear if that is still operating or whether it could also be removed to make room for an SCR installation. In addition, there may be other options for the location of the SCR system. Depending on the proximity of the gas turbines, it is possible that one SCR reactor could be used by both Units 17 and 18, which would reduce costs and potentially be easier to install at the site. NMED must require all possibilities for SCR installation be evaluated and documented by Enterprise. The state must not simply discount this highly effective NOx control based on a claim of some retrofit difficulty.

In terms of the costs of SCR control, NPCA's March 2020 Oil and Gas Four-Factor Report showed the cost effectiveness in 1999 dollars for SCR achieving about 90% NOx reductions would range from $2,000/ton to $3,400/ton for a 5 MW combustion turbine (~6800 hp engine) depending on the operating capacity factor, and costs decrease for larger turbines like Units 17 and 19 which are approximately 19,500 hp engines.[46] For much larger combustion turbines of 75 MW

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[42] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 2-4.
[43] *See* Seebold, James et al., Gas Turbine NOx Reduction Retrofit, available at https://www.onepetro.org/conference-paper/SPE-66501-MS.
[44] November 2007 Title V Permit Application for Chaco Gas Plant, Part 3 at pdf page 16.
[45] *Id.*
[46] *See* NPCA March 2020 Oil and Gas Four-Factor Report at 75.

generating capacity (~100,500 hp), cost effectiveness of SCR was significantly lower in the range of $560-$850/ton depending on operating capacity factor.[47]

To get an idea of the costs for SCR at Units 17 and 18 in current dollars, one can use EPA's SCR cost spreadsheet made available as part of EPA's Control Cost Manual.[48] While the EPA SCR cost spreadsheet was not specifically designed for simple cycle gas combustion turbines, it can be modified to estimate SCR cost for gas-fired combustion turbines. It seems likely that this EPA cost spreadsheet for boilers will overestimate the cost of SCR for natural gas-fired combustion turbines. This is because gas turbines, particularly those used in power generation, are routinely equipped with SCR systems, and for simple cycle gas turbines, the SCR systems are typically placed in an enclosure attached to the combustion turbine exhaust.[49] Boilers are not as commonly equipped with SCR compared to natural gas combustion turbines, and the SCR placement is more complicated with its placement usually between the economizer and air preheater and upstream of pollution control equipment. This EPA SCR cost spreadsheet is based on cost assumptions from the Integrated Planning Model (IPM) and those costs are, in turn, based on actual SCR retrofit costs for boilers.[50] Because SCR systems are more commonly applied at gas combustion turbines, especially those used in power generation (including simple cycle turbines) and because SCR installation at a simple cycle combustion turbine is often more straightforward than at a boiler, the EPA SCR cost spreadsheet likely overestimates the cost of SCR for a natural gas-fired combustion turbine. Thus, to generate a more current cost estimate of SCR for the natural gas-fired combustion turbines of Units 17 and 18 at the Chaco Gas Plant, EPA's SCR cost spreadsheet was also used to estimate SCR cost effectiveness.

For this analysis, Enterprise's claimed baseline NOx emission rates of 54.7 ppm and 48.7 ppm for Units 17 and 18, respectively, were used. These are assumed to be reflective of ppm by dry volume at 15% oxygen. As previously discussed, NMED should ensure that this 2016 test data reflects operations at maximum operating capacity and ensure that these emission rates are a reasonable projection of NOx emissions as of 2028, especially given that past NOx emission rates have been identified as significantly higher than these NOx rates. The company's actual NOx rates were converted to lb/MMBtu emission rates using a conversion formula from EPA's

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[47] *Id.*

[48] While this spreadsheet was not identified to be used with natural gas-fired combustion turbines, as EPA states that its use is for boilers fired by coal, fuel oil, or natural gas with heat input greater than 250 MMBtu/hr or generating capacity greater than or equal to 25 MW, the spreadsheet can be used to estimate SCR capital and operations costs for any fossil fuel-fired unit as long as the necessary input data is available. In fact, it has been utilized by several oil and gas facilities in their four-factor analyses to NMED.

[49] *See*, e.g., Managing the Catalysts of a Combustion Turbine Fleet, Power, April 30, 2012, under 2. Typical simple cycle SCR. Available at https://www.powermag.com/managing-the-catalysts-of-a-combustion-turbine-fleet/.

[50] *See* Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, SCR Cost Development Methodology, January 2017, at 1, available at https://www.epa.gov/airmarkets/ipm-v6-emission-control-technologies-attachment-5-3-scr-cost-development-methodology.

1993 Gas Turbine ACT.[51] Enterprise's ppm NOx baseline rates thus were converted to 0.22 lb/MMBtu for Unit 17 and 0.20 lb/MMBtu for Unit 18. With this data, the authors input unit-specific information into EPA's SCR cost spreadsheet to estimate cost effectiveness of SCR at Units 17 and 18, including the altitude of the site listed in the 2007 Title V permit application of 6,020 feet and the exhaust gas temperature of 766 degrees Fahrenheit.[52] Two different SCR control levels were assumed: approximately 70% control to achieve a 15 ppmvd NOx rate and a 90% control efficiency to achieve approximately a 5 ppmvd NOx emission rate. In an analysis of SCR cost effectiveness from an uncontrolled gas turbine, NESCAUM estimated that a 15 ppmvd NOx rate reflective of 90% NOx control (from uncontrolled NOx rates) could be achieved with SCR.[53] As stated above, the 2016 baseline emission rates assumed by Enterprise are much lower than worse case NOx rates, and a 15 ppmvd limit only reflects 70% control across the SCR, when such controls can achieve 90% or greater NOx reduction. Thus, two levels of NOx emission reduction were assumed to reflect a low and a high level of NOx reduction with the SCR. The heat value of the fuel and hourly heat input for Units 17 and 18 identified in Part 3 of Enterprise's 2007 Title V permit application (i.e., 1,245 Btu/standard cubic feet and 181 MMBtu/hr)[54] were assumed to reflect current operations at the units. With Enterprise's 2016 actual annual NOx emissions and its reported ppm NOx emissions and the reported heat value of the fuel, actual annual gas consumption rates were estimated for each unit for input into the SCR cost spreadsheet. Capital costs were annualized applying a cost recovery factor using a 4.7% interest rate and a 25-year life which EPA has identified as typical for SCR systems used at industrial boilers.[55] Last, two different reagent types were evaluated: 29% aqueous ammonia and 50% urea solution. Urea was evaluated due to concerns raised by Enterprise in the use of ammonia as a reagent because, with urea used as a reagent, the concerns from hazards of using pressurized ammonia do not apply. The results of these analyses are provided in Table 1 below.

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[51] *See* EPA, Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines, EPA-453/R-93-007, January 1993, Appendix A which has conversion equations for natural gas-fired combustion turbines.
[52] November 2007 Title V Permit Application for Chaco Gas Plant, Part 3 at pdf pages 12 and 13.
[53] NESCAUM 2000 Status Report at III-21 through III-24 and at III-40 (see references 11, 16, 9, 14, and 15).
[54] November 2007 Title V Permit Application for Chaco Gas Plant, Part 3 at pdf pages 11-12.
[55] *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80.

Table 1. Cost Effectiveness of SCR at Chaco Gas Plant Units 17 and 18 GE Frame 5 Gas Combustion Turbines, Using EPA's SCR Cost Calculation Spreadsheet for Boilers

Unit	Assumed NOx Removal Efficiency with SCR	Capital Cost of SCR (2018 $)	Annual O&M Costs with 29% Ammonia	Annual O&M Costs with Urea	NOx Removed from 2016 Baseline, tpy	Cost Effectiveness of SCR with Ammonia (2018 $), $/ton	Cost Effectiveness of SCR with Urea (2018 $), $/ton
17	72%	$5,725,135	$95,677	$125,129	79	$6,264	$6,638
17	90%	$5,725,135	$100,385	$137,200	98	$5,059	$5,433
18	70%	$5,725,135	$110,586	$144,582	91	$5,591	$5,965
18	90%	$5,725,135	$116,197	$159,905	117	$4,396	$4,771

The cost estimates of SCR based on EPA's boiler SCR cost spreadsheet project costs for SCR that are significantly lower than Enterprise's water or steam injection capital cost estimates, which were projected to range from $6.6 to $8.7 million, as well as the company's annual operating cost estimates, which ranged from $1.2 to $1.8 million per year.[56] Given that SCR can achieve much higher levels of control at much lower costs than water or steam injection, NMED must require Enterprise to more fully evaluate the ability to install SCR at Unit 17 and/or 18. Ninety percent control should be readily achievable with SCR at these units to meet a NOx emission rate of 5 ppmvd (0.02 lb/MMBtu). Before allowing Enterprise to dismiss SCR due to claims that it is not feasible to locate one or more SCR reactors at Units 17 and 18, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at Units 17 and 18, including any potential options for a shared SCR system between Units 17 and 18 if such options exist. SCR can be a very effective method for reducing NOx emissions from the Units 17 and 18 gas turbines and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for Units 17 and 18 at the Chaco Gas Plant.

C. Solar Mars T-15000 Turbines

Units 35, 36, and 37 at the Chaco Gas Plant are 15,000 horsepower natural gas-fired Solar Mars T-15000 combustion turbines that were constructed in 1996.[57] The units each have a NOx emissions limit of 76.2 lb/hr and 333.6 tpy.[58] For these units, Enterprise identified dry low NOx combustors made by the turbine manufacturer ("SoLoNOx") as a viable control technology, but claimed that SCR was not possible for these turbines due to retrofit difficulty; namely, due to the size estimates of the SCR.[59] As previously discussed, there is no question that SCR is

[56] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 8-1 to 8-3.
[57] Title V Operating Permit P116-R2M1 for Chaco Natural Gas Processing Plant at A7.
[58] *Id.* at A11.
[59] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 2-4.

technically feasible for natural gas-fired combustion turbines, including those used at compressor stations.

1. SoLoNOx at Units 35, 36, and 37

Enterprise evaluated SoLoNOx for the Solar Mars turbines of Units 35, 36, and 37, stating that it could reduce NOx concentrations down to 15 ppmv which reflects 85-88% NOx reduction efficiency from the 2016 stack test data that Enterprise assumed as baseline emissions.[60] NMED must ensure that the 2016 stack test data reflect actual emissions from the units and expected actual emissions from the units in 2028.

Enterprise's cost estimates for SoLoNOx at Units 35, 36, and 37 are based on vendor quotes from Solar Turbines.[61] Enterprise then determined cost effectiveness of SoLoNOx controls to meet a 15 ppmv NOx emissions rate, using an interest rate of 8.38% and an assumed life of controls of 20 years.[62] As previously discussed, a 4.7% interest rate is more reflective of current and likely near future interest rates. In terms of the life of SoLoNOx controls, the combustors should last the life of a combustion turbine, which is at least 25 years. Thus, to more accurately reflect cost effectiveness for the SoLoNOx controls at Units 35, 36, and 37, Enterprise's cost effectiveness calculations were revised to reflect a 4.7% interest rate and a 25-year life of controls. The revised costs are reflected in Table 2.

Table 2. Revised Cost Effectiveness of SoLoNOx at Units 35, 36, and 37 of the Chaco Gas Plant, to Reflect a 4.7% Interest Rate and a 25 Year Life

Unit	Enterprise's Total Annual Costs of SoLoNOx (at 8.38% Interest and 20-Year Life)	Enterprise's Cost Effectiveness at 8.38% Interest and 20 Year Life	Revised Total Annual Costs of SoLoNOx	Revised Cost Effectiveness at 4.7% Interest and 25-Year Life
35	$715,215	$6,800/ton	$512,744	$4,875/ton
36	$688,967	$6,668/ton	$495,494	$4,796/ton
37	$693,345	$9,434/ton	$498,371	$6,781/ton

Thus, SoLoNOx at Units 35, 36, and 37 should be considered much more cost effective than reflected in Enterprise's cost analysis.

[60] *Id.* at 2-2.
[61] *Id.* at 3-2.
[62] *Id.* at 8-4 through 8-6.

2. SCR at Units 35, 36, and 37

As with Units 17 and 18, Enterprise did not evaluate SCR for Units 35, 36, and 37, claiming it was "not possibly to install these units at the Chaco facility" due to "the amount of buffer space needed to maintain accessibility to equipment and to avoid compromising worker safety."[63] For the reasons discussed above in Section I.B.3, NMED must request more information and documentation before allowing Enterprise to dismiss SCR due to claims that it is not feasible to locate one or more SCR reactors at Units 35, 36, and 37. NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at Units 35, 36, and 37, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions from the Units 35-37 gas turbines and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for Units 35-37 at the Chaco Gas Plant.

There are two options for the evaluation of cost effectiveness of SCR at Units 35, 36 and 37: One is to consider SCR as a control option without SoLoNOx installed. A second option is to consider SoLoNOx plus SCR as the maximum achievable reductions in NOx emissions. As discussed in the NPCA March 2020 Oil and Gas Four-Factor Report, SCR has recently been proposed to be installed at several compressor stations.[64] Once such compressor station is the Buckingham Compressor station to be located in Virginia. That compressor station was proposed to be constructed with Solar Mars combustion turbines equipped with SoLoNOx and SCR to achieve a NOx emission rate of 3.75 ppmv @ 15% oxygen.[65] SCR installed along with the SoLoNOx combustion control could achieve 96 to 97% reduction in NOx emissions from Units 35, 36, and 37. However, emission rates with SoLoNOx and SCR at gas-fired combustion turbines could be even lower, as best available control technology (BACT) or Lowest Achievable Emission Rate (LAER) for such turbines operated for power generation are generally set at 2 to 2.5 ppmv at 15% oxygen.[66]

To get an idea of the costs for SCR at Units 35, 36, and 37 in more current dollars, we used EPA's SCR cost spreadsheet made available as part of EPA's Control Cost Manual. Two different costs analyses were completed for these comments: 1) SCR plus SoLoNOx to achieve a 3.75 ppmv NOx rate and 2) SCR by itself to achieve 15 ppmv. The costs analyses were based on the

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[63] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 2-4.
[64] NPCA March 2020 Oil and Gas Four-Factor Report at 89.
[65] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.
[66] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand and Curve Reset, at 9.

use of a 50% urea solution as the reagent. As shown in Table 1 above, if a 29% aqueous ammonia reagent is used, the cost effectiveness will be lower than if urea is used – thus, these cost estimates reflect a worst case estimate. The company's actual NOx rates and the emission limits evaluated were converted to lb/MMBtu emission rates for input into EPA's SCR spreadsheet using a conversion formula from EPA's 1993 ACT for Gas Turbines.[67] With this data, unit-specific information was input into EPA's SCR cost spreadsheet to estimate cost effectiveness of SCR at Units 35-37, including the altitude of the site listed in the 2007 Title V permit application of 6,020 feet and the exhaust gas temperature of the turbines of 907 degrees Fahrenheit.[68] The heat value of the fuel and hourly heat input for Units 35-37 identified in Part 3 of Enterprise's 2007 Title V permit application (i.e., 900 Btu/standard cubic feet[69] and 91.2 MMBtu/hr)[70] were assumed to reflect current operations at the units. With Enterprise's 2016 actual annual NOx emissions and its reported ppm NOx emissions and the reported heat value of the fuel, actual annual gas consumption rates were estimated for each unit for input into the SCR cost spreadsheet. Capital costs were annualized applying a cost recovery factor using a 4.7% interest rate and a 25-year life which EPA has identified as typical for SCR systems used at industrial boilers.[71] To determine cost effectiveness of SoLoNOx plus SCR, the revised annualized costs of SoLoNOx at a 4.7% interest rate and a 25 year life were added to the costs of SCR to reduce NOx emissions from 15 ppmv to 3.75 ppmv. The results of these analyses are provided in Table 3 below.

Table 3. Cost Effectiveness of SCR Plus SoLoNOx at Chaco Gas Plant Units 35, 36, and 37 Solar Mars T15000 Turbines to Reduce NOx to 3.75 ppmv, Using EPA's SCR Cost Calculation Spreadsheet with Urea Reagent (2018 $)

Unit	Revised Total Annual Costs of SoLoNOx (at 4.7% Interest and 25-Year Life)	Capital Cost of SCR to Reduce NOx from 15 ppmv to 3.75 ppmv	Annual O&M Costs of SCR	Total Annual Costs of SCR	Total Annual Costs of SoLoNOx Plus SCR	NOx Reduced with SoLoNOx and SCR, tpy	Cost Effectiveness of SoLoNOx plus SCR, $/ton
35	$512,744	$3,666,834	$53,222	$308,349	$821,093	115.9	$7,082/ton
36	$495,494	$3,666,834	$53,361	$308,488	$803,982	114.2	$7,039/ton
37	$498,371	$3,666,834	$50,409	$305,536	$803,907	82.8	$9,704/ton

[67] *See* EPA, Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines, EPA-453/R-93-007, January 1993, Appendix A which has conversion equations for natural gas-fired combustion turbines.
[68] November 2007 Title V Permit Application for Chaco Gas Plant, Part 3 at pdf page 24.
[69] Note that it is not clear that this reflects the high heating value of the fuel used at Units 35-37, especially given that the heat value of the fuel used at Units 17 and 18 was tested as having a much higher heat value of 1,245 Btu/scf. However, it is the heat value listed in the 2007 Title V permit application as specific to these units, so it is used here.
[70] November 2007 Title V Permit Application for Chaco Gas Plant, Part 3 at pdf page 24.
[71] *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80.

Table 4. Cost Effectiveness of SCR at Chaco Gas Plant Units 35, 36, and 37 Solar Mars T15000 Turbines to Reduce NOx to 15 ppmv, Using EPA's SCR Cost Calculation Spreadsheet with Urea Reagent (2018 $)

Unit	Capital Cost of SCR	Annual O&M Costs	Total Annualized Costs of SCR	NOx Removed from 2016 Baseline, tpy	Cost Effectiveness of SCR, $/ton
35	$3,666,834	$104,172	$359,298	105.2	$3,416/ton
36	$3,666,834	$103,345	$358,472	103.4	$3,468/ton
37	$3,666,834	$85,814	$340,940	73.5	$4,642/ton

As shown by a comparison of Table 4 to Table 2, the costs of SCR to achieve the same level of NOx reduction as SoLoNOx at Units 35-37 is lower than the cost of SoLoNOx. As previously stated, costs were only provided for urea-based SCR. If aqueous ammonia was used as the reagent, the costs of SCR would be lower.

Clearly, SCR alone appears to be a more cost effective method to reduce NOx emissions from Units 35-37 by 85-88% control compared to SoLoNOx. Further, SCR used in combination with SoLoNOx can achieve the greatest reductions in NOx at these units. Thus, NMED must require further evaluation of the feasibility of installing SCR at Units 35, 36, and 37, including asking Enterprise to obtain vendor analyses of the site and feasibility of SCR retrofits.

D. Units 12, 13, and 14: Clark TLA-10 2-Stroke Lean Burn RICE

Units 12, 13, and 14 are two-stroke lean-burn RICE that were constructed in 1996, each with a capacity of 3,400 hp.[72] The units each have an hourly NOx limit of 49.7 lb/hr and an annual NOx limit of 218 tpy.[73] Enterprise states in its four-factor analysis that the NOx emissions from these units are calculated from stack test data from 4/18/1995.[74] This date seems possibly incorrect, or the permit is incorrect as it identifies the units as being constructed in 1/1/1996. Enterprise further states that the maximum hourly emission rate corresponds to a NOx exhaust concentration of 1,032 ppmv.[75] That is the extent of information provided on the actual NOx emissions from these units. NMED should request more information on the units' current hours of operation and actual NOx emissions.

[72] Title V Operating Permit P116-R2M1 for Chaco Natural Gas Processing Plant at A6.
[73] *Id.* at A10.
[74] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 2-5.
[75] *Id.*

1. Use of Low Emission Combustion Technology

Enterprise claims that the Clark TLA-10 engines are currently operating with "Clean Burn Technology (CBT)."[76] Yet, the stated maximum hourly NOx rate of 1,032 ppmv does not reflect the levels of NOx emissions typically expected with such low emission combustion (LEC) technology. This NOx concentration is equivalent to 14 grams per horsepower-hour (g/hp-hr).[77] Note, the hourly NOx permit limits for these units of 49.7 lb/hr, corresponding to a NOx limit of 7 g/hp-hr for each 3,400 hp engine.[78] And, in fact, the information provided as part of permit applications for the source, in 2007 and in 2016, indicate that these three units were initially retrofitted with the Controlled Rapid Burn (CRB™) systems from Diesel Supply Company, guaranteeing NOx emission rates of 7 g/hp-hr.[79] But even this controlled NOx emission level does not reflect the levels of NO_x emissions achievable with LEC technology. In order to effectively evaluate a company's assessment of LEC, a more precise definition of LEC technologies and associated achievable emission rates is needed.

EPA has examined source test data from large natural gas-fired lean burn engines and has affirmed that these data support an uncontrolled emission rate from these engines, generally, of 16.8 g/hp-hr.[80] More specifically, these source test data include individual data for three Clark TLA-10 engines with uncontrolled emission rates of 16 g/hp-hr and two Clark TLA-10 engines with uncontrolled emission rates of 7 g/hp-hr.[81] Even the permitted NOx limit of 7 g/hp-hr for the engines at the Chaco Gas Plant could therefore reflect an uncontrolled emission rate, although it appears these engines were retrofit with certain combustion modifications to reduce NOx emissions by 50% (i.e., CRB™ technology to reduce NOx emissions from 14 g/hp-hr to 7 g/hp-hr). Controlled NOx emission rates with LEC are typically much lower. NPCA's March 2020 Oil and Gas Four-Factor Report stated that a wide range of emission rates are achievable

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[76] *Id.* at 2-7.

[77] Using the following EPA conversion factors for uncontrolled lean burn engines (73 ppmv = 1 g/bhp-hr) and lean-burn engines controlled with LEC technology (73 ppmv = 1 g/bhp-hr), NOx emission rates would be 13.8 g/bhp-hr (assuming LEC control) or 14.1 g/bhp-hr (uncontrolled). *See* EPA-457/R-00-001 *Stationary Reciprocating Internal Combustion Engines Updated Information on NOx Emissions and Control Techniques,* September 2000, p. 2-1, *available at*: https://nepis.epa.gov/Exe/ZyPDF.cgi/P100V343.PDF?Dockey=P100V343.PDF [hereinafter referred to as "EPA 2000 RICE Update"]. NOTE: this emission rate of 14 g/hp-hr appears to represent the uncontrolled emission rate, prior to retrofits to the units that reduced NOx emission by 50% and reflected in the permitted 49.7 lb/hr limit for these 3,400 hp engines (14 g/hp-hr * 3,400 hp / 453.6 g/lb = 100 lb/hr; 7 g/hp-hr * 3,400 hp / 453.6 g/lb = 50 lb/hr).

[78] Title V Operating Permit P116-R2M1 for Chaco Natural Gas Processing Plant at A10.

[79] *See,* Chaco Title V Renewal Permit P-116 Part 3 November 2007 *and* Chaco Permit 1555-M5 Significant Revision Application January 2016 *Emissions Support Data, Clark TLA-10 Compressor Engines, Retrofit Units 12—14*.

[80] *See* EPA Stationary Reciprocating Internal Combustion Engines Technical Support Document for NOx SIP Call (October 2003) at 5, *available at:* http://www.valleyair.org/workshops/postings/2011/8-18-11-rule4702/R4702%20APPF.pdf.

[81] *Id*. at 6 and 7.

with LEC technology, with NOx emissions generally no higher than 2 g/hp-hr and often significantly lower (e.g., as low as 0.5 g/hp-hr).[82]

For reference, the following additional sources of information regarding NOx emission rates specific to Clark TLA model engines – both uncontrolled and with LEC technology – are provided here:

- EPA's 2000 RICE Update includes NOx emissions test data for specific engines, including Clark Model TLA-6, 2-stroke, lean-burn, 2,000 hp RICE retrofitted with LEC. According to EPA, six engines retrofitted by a third-party vendor had NOx emission rates ranging from 0.8–1.4 g/bhp-hr, with a mean of 1.0 g/bhp-hr.[83]

- An evaluation by a technical group for the Pipeline Research Council International looked at three of the most representative make / models of 2-stroke lean-burn compressor engines: (1) 2,250 hp Cooper GMVH-10; (2) 2,000 hp Clark TLA-6; and (3) 2,500 hp Cooper GMW-10. According to a technical report by the Ozone Transport Commission (OTC) describing this evaluation, "[t]he evaluation concluded that there were no technology gaps and that each of the three makes/models evaluated were capable of attaining a NOx emissions limitation of 0.5 g/bhp-hr using a combination of improvements and retrofits related to air supply, fuel supply, ignition, electronic controls, and engine monitoring."[84]

- In 2002, EPA collected data on emission rates of lean burn engines that have been retrofitted with LEC, including data from several state agencies for specific engine models.[85] Test results for 20 Clark TLA engines ranged from 0.4 to 2.9 g/hp-hr, with an average controlled NOx rate of 1.5 g/hp-hr.[86]

More generally, the 2012 OTC Report suggests that, "combustion related modifications have the potential to achieve from 60% to 90% reduction in NOx emissions [or, "an approximate range of NOx emissions rate of 3.0 g/bhp-hr to 0.5 b/bhp-hr"] from two-stroke lean-burn spark ignited reciprocating engines, depending upon the make/model configuration of the engine." Specifically, the 2012 OTC Report discusses the use of "layered combustion controls"

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[82] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 28.
[83] EPA 2000 RICE Update at 4-8.
[84] Ozone Transport Commission, Technical Information, Oil and Gas Sector, Significant Stationary Sources of NOx Emissions, Final, October 17, 2012, p. 24, *available at*: https://otcair.org/upload/Documents/Meeting%20Materials/Final%20Oil%20%20Gas%20Sector%20TSD%2010-17-12.pdf [hereinafter referred to as "2012 OTC Report"].
[85] *See* EPA Stationary Reciprocating Internal Combustion Engines Technical Support Document for NOx SIP Call (October 2003) at 15, *available at:* http://www.valleyair.org/workshops/postings/2011/8-18-11-rule4702/R4702%20APPF.pdf
[86] *Id.* Table 4.

in order to achieve emission rates at the lower end of this range, that include: improved airflow, improved fuel-air mixing, improved ignition, and upgraded controls.[87] According to the 2012 OTC Report, the higher emission rates in this range would tend to be more representative of situations where layered combustion controls packages have not been commercialized.[88]

More recently, EPA describes layered combustion (LC) as demonstrated control techniques for 2-stroke lean-burn engines, achieving a NOx emission rate of 0.5 g/hp-hr.[89] Specifically, EPA described LC as consisting of multiple combustion modifications, including: (1) high pressure fuel injection; (2) turbocharging; (3) a precombustion chamber; and (4) cylinder head modifications.[90]

Also, recently, EPA described LEC retrofit kits designed to achieve extremely lean air-to-fuel ratios – in order to minimize NOx emissions – as encompassing the following similar retrofit technologies:

- Redesign of cylinder head and pistons to improve mixing (on smaller engines)
- Precombustion chamber (on larger engines)
- Turbocharger
- High energy ignition system
- Aftercooler
- Air-to-fuel ration controller (AFRC)[91]

It is not entirely clear what specific combustion and LEC technologies are employed for the Clark TLA-10 engines at the Chaco Gas Plant. Enterprise states that these engines are currently operating with "Clean Burn Technology" and discusses that to generally mean the use of high energy ignition system, turbocharger, and AFRC technologies.[92] The Controlled Rapid Burn (CRB™) retrofit kits originally installed on Units 12–14 appear to include pre-chambers and high

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[87] *Id.*
[88] *Id.*
[89] 2016 EPA Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS (Docket ID No. EPA-HQ-OAR-2015-0500), Appendix A at 5-5, *available at:* https://19january2017snapshot.epa.gov/sites/production/files/2015-11/documents/assessment_of_non-egu_nox_emission_controls_and_appendices_a_b.pdf [hereinafter referred to as "CSAPR TSD for Non-EGU NOx Emissions Controls"].
[90] *Id.* at 5-7.
[91] EPA, Final Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Docket ID EPA-HQ-OAR-2015-0500-0508, Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance, August 2016, Appendix A at 5-3, *available at:* https://www.regulations.gov/document?D=EPA-HQ-OAR-2015-0500-0508 [hereinafter referred to as "2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls"].
[92] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 2-7.

flow fuel valves.[93] However, the controls at these units are not achieving NOx emission levels commensurate with LEC.

EPA noted, in its 2000 Updated Information on NOx Emissions and Control Techniques for RICE, that "CleanBurn" is a trademark of Cooper Energy Systems, and that industry comments on its draft AP-42 emission factors for stationary internal combustion engines objected to a "clean burn" designation for that reason.[94] EPA's 1997 draft AP-42 section for stationary internal combustion sources defined "clean burn" engines as separate engine families (*i.e.*, distinct from other 2-stroke and 4-stroke lean-burn engines), equipped with "LEC precombustion chamber technology" and identified the following NOx emission factors for these distinct LEC-equipped "engine families":

> (1) 1.1 g/bhp-hr (2-stroke clean-burn engines); and
>
> (2) 0.5 g/bhp-hr (4-stroke clean-burn engines).[95]

EPA's 2000 RICE Update notes that, "[t]oday, many engine manufacturers refer to their engines equipped with precombustion chambers simply as "lean-burn engines"."[96] And EPA's final AP-42 section on natural gas-fired reciprocating engines clarified the term, as follows:

> Some lean-burn engines are characterized as clean-burn engines. The term "clean-burn" technology is a registered trademark of Cooper Energy Systems and refers to engines designed to reduce NOx by operating at high air-to-fuel ratios.[97]

A recent Interstate Natural Gas Association of America (INGAA) Report provides some information on Clark TLA engine stock components and retrofit modification / upgrade options.[98] Examples from this report include: upgrading stock turbocharger and stock intercooler systems; upgrading stock low pressure direct fuel systems to high pressure fuel injection and control systems; and upgrading controls for the stock fuel system.[99] Based on the

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[93] *See* 5/12/95 Bid from Diesel Supply Company to El Paso Natural Gas Company for "converting your Clark TLA-10 engines at your CHACO plant." This bid is included in the Chaco Title V Renewal Permit P-116 Part 3 November 2007 *and* Chaco Permit 1555-M5 Significant Revision Application January 2016 *Emissions Support Data, Clark TLA-10 Compressor Engines, Retrofit Units 12—14*. *Also, see:* https://www.dieselsupply.com/.
[94] EPA 2000 RICE Update at p. 4-8.
[95] *Id. See discussion at* 3-9.
[96] *Id.* at 4-8.
[97] EPA AP-42 Chapter 3, Section 3.2 (July 2000) at 3.2-2, *available at:* https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s02.pdf.
[98] INGAA, Report No. 2016-6, *Potential Impacts of the Ozone and Particulate Matter NAAQS on Retrofit NOx Control for Natural Gas Transmission and Storage Compressor Drivers* (December 2017), *available at:* https://www.ingaa.org/File.aspx?id=33789.
[99] *Id. See, e.g.,* Table 6 at 18.

information in this report, Clark TLA model engines come equipped with a single turbo, an intercooler system, and a low pressure direct fuel system. The INGAA report evaluated controls for various regulatory scenarios that would achieve NOx emission levels in the 1–3 g/hp-hr range.[100]

LEC retrofit costs specific to Clark TLA model engines are reported in the INGAA report, ranging from $300–$600 per hp, for upgrades to the scavenging, intercooler, and fuel systems.[101] The INGAA report doesn't specify what year the cost data are from so we assume it reflects the timeframe of the report, or 2017$. Using these cost data, we can estimate the cost effectiveness of retrofitting Units 12, 13, and 14 at the Chaco Gas Plant. Retrofit costs for each 3,400 hp unit using INGAA's cost data would range from $1.02–$2.04 million, in 2017$. Using the Chemical Engineering Plant Cost Indices, these costs could increase to $1.08–$2.17 million, in 2018$.[102] It's not clear if operating costs are included in these estimates; to be conservative, annual operating costs of the LEC controls are assumed to be 15% of capital costs.[103]

The cost effectiveness of retrofitting these engines with LEC to meet a 2 g/hp-hr NOx emissions rate, based on the units' uncontrolled emission rate, is presented in the table below. The original retrofits to these units resulted in controlled NOx emission rates of 7 g/hp-hr possibly employing some of the upgrades associated with LEC. This analysis shows the cost effectiveness of an LEC retrofit that can achieve an emission level between 1–3 g/hp-hr based on current technologies and costs. The operating schedule for these engines at the Chaco Gas Plant is unknown but we present cost effectiveness for 8,000 operating hours per year since annual facility NOx emissions indicate that the units operated near capacity in 2016.[104] Note, this analysis uses an interest rate of 4.7%, reflective of current and likely near future interest rates.[105] Further note, the LEC controls are assumed to last 25 years, consistent with other cost effectiveness analyses submitted to NMED for LEC controls.[106]

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[100] *Id.* at 23.
[101] *Id.*
[102] Based on multiplying the cost estimate from the 2017 INGAA report by the ratio of the CEPCI indices for 2018 to 2017 (603.1/567.5).
[103] This assumption is consistent with cost data provided for the October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9, however it results in much higher O&M costs than those used in Targa's (Eunice, Monument, and Saunders Gas Plants) and Harvest Four Corners' (Kutz Canyon Gas Plant) four-factor analyses—which ranged from $40,000/yr to $100,000/yr—and than those used for ETC Texas Pipeline's Jal No. 3 Gas Plant, which assumed O&M costs would be 13% of capital costs.
[104] *See* NMED's Emissions Analysis tool, which reports 2016 NOx emissions of 2,258.9 tons per year, compared to total annual NOx PTE for the units evaluated in Enterprise's four-factor analysis for the Chaco Gas Plant of 2,342.8 tons per year (*see* Table 1 of the November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 1-1).
[105] As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.
[106] *See* 2019 Four-Factor Analyses for Roswell Compressor No. 9 and Jal No. 3..

Table 5. Cost Effectiveness of LEC at Uncontrolled Chaco Gas Plant Units 12, 13, and 14 to Reduce NO_x Levels to 2 g/hp-hr, Assuming a 4.7% Interest Rate and a 25-Year Life, 2018 $

Unit	Capital Cost of LEC to Reduce NOx from the Uncontrolled rate of 14 g/hp-hr	Annual O&M Costs (assume 15% of Capital Costs)	Total Annualized Costs of LEC to Reduce NOx to 2 g/hp-hr (~85% NOx Reduction)	NOx Removed, tpy operating 8,000 hr/yr	Cost Effectiveness of LEC operating 8,000 hr/yr, $/ton
12	$1,083,986–$2,167,972	$162,598–$325,196	$237,213–$474,426	360	$659/ton–$1,319/ton
13	$1,083,986–$2,167,972	$162,598–$325,196	$237,213–$474,426	360	$659/ton–$1,319/ton
14	$1,083,986–$2,167,972	$162,598–$325,196	$237,213–$474,426	350	$659/ton–$1,319/ton

LEC at Units 12, 13, and 14 would be even more cost effective than what is shown if retrofits at these engines could meet even lower NOx emission levels, less than 2 g/hp-hr. Note, an analysis of individual upgrades at the units at the Chaco Gas Plant is not possible without knowing which specific LEC technologies are already employed to meet the permitted emission rate of 7 g/hp-hr and which additional possible upgrades could be installed to achieve even greater emissions reductions. NMED must ask for a list of specific LEC technologies employed at Units 12–14 and an evaluation of additional applicable LEC technologies for these units. NMED should require additional LEC retrofit techniques be evaluated in order to assess the cost effectiveness of further reducing NOx emissions from these engines to a level more in line with current LEC technology – i.e., emission levels in the 0.5–2 g/hp-hr range.

2. Use of SCR.

Enterprise did not evaluate SCR for Units 12, 13, and 14, primarily because it claimed that it was not possible to install SCR at these units due to space limitations.[107] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at Units 12, 13, and 14, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for Units 12-14

[107] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 2-6.

at the Chaco Gas Plant, particularly because Enterprise has not evaluated any other NOx reduction strategy for these units.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[108]

If Clean Burn or other low emissions technology is not a viable or cost-effective control for lean burn engines, SCR could possibly be a more cost-effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[109] In Section XX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[110] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

II. DCP Midstream – Eunice Gas Plant

The DCP Midstream Eunice Gas Plant is a natural gas processing plant located in Lea County, New Mexico. A NMED Statement of Basis for the plant's Title V permit describes the plant as follows: "The Eunice plant consists of an Inlet Receiving System, Amine Treater, Sulfur Recovery Plant, Inlet Compression, Dehydration, Cryogenic/Turbo Expansion Plant with External Propane Refrigeration, and product sales for Residue Gas, NGLs, and Condensate. Supporting systems and operations at the plant include Fuel Gas Systems, Instrument and Starting Air Systems, a Heat Medium (Hot Oil) System, Cooling Towers, Process Flare, Acid Gas Flare, and Drain Systems. Processing operations at the plant include chemical reaction processes, thermodynamic processes, and physical processes."[111] The plant separates heavier hydrocarbons that can be condensed into liquids (called "Natural gas liquids or NGLs" and removes impurities from the natural gas such as water, hydrogen sulfide (H2S) gas, and carbon dioxide gas.[112]

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[108] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[109] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[110] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[111] NMED Statement of Basis – Narrative, Title V Permit, for Permit Nos. 0044-M-10-M10R6 and P086-R3, at 1.
[112] *Id.*

According to the permit, the plant includes several four-stroke lean-burn RICE, several natural gas-fired turbines, boilers, a heater, gas sweetening equipment (amine unit, sulfur recovery unit (SRU) incinerator, acid gas and SRU flares), and other emission units.[113] In DCP Midstream's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Solar Centaur Turbines: Units 17A, 18B, 19A, 25A, and 26A
- Amine Unit controlled by SRU Incinerator: Unit 31
- Startup, Shutdown, Malfunction (SSM).[114]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[115] The following provides a review of the company's four-factor analyses for the turbines. The analysis for the amine unit and SSM emissions is addressed in Section XXIII. below.

A. Interest Rate Used in Cost Analyses.

DCP Midstream used a 5.5% interest rate in the cost analyses for all of the controls evaluated in its 4-factor analyses.[116] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. This is the same interest rate that EPA has used in its cost spreadsheet for SCR, but EPA also states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[117] The current bank prime rate is 3.25%.[118] The highest the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[119] In a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[120] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable

[113] Title V Operating Permit P086-R3 for DCP Eunice Gas Plant at A6 to A8.
[114] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Eunice Gas Plant at 1-2.
[115] *Id.*
[116] *Id.* at Section 8.0 Supporting Documentation.
[117] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[118] https://www.federalreserve.gov/releases/h15/.
[119] https://fred.stlouisfed.org/series/DPRIME.
[120] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.

progress controls. For these reasons, in the cost effectiveness calculations provided herein, a 4.7% interest rate is used rather than a 5.5% interest rate.

B. Solar Centaur Natural Gas-Fired Combustion Turbines (Units 17A, 18B, 19A, 25A, and 26A).

The combustion turbines evaluated at the Eunice Gas Plant are Solar combustion turbines, model T-4002 of 3329 hp capacity (Units 17A, 25A, and 26A) and model T-4502 (Units 18B and 19A) of 3372 hp capacity.[121] These units were constructed between 1974 and 1986.[122] Units 18A and 19A are subject to a NOx emission limit of 165.85 ppmv at 15% O_2 and Units 25A and 26A are subject to a NOx limit of 158.76 ppmv at 15% O_2, pursuant to 40 C.F.R. Part 60, Subpart GG.[123] Under the terms of the permit, the units are also subject to the following hourly and annual emission limits of NOx.

Table 6. Limits from DCP Midstream Title V Permit for the Eunice Gas Plant Combustion Turbines[124]

Combustion Turbine Unit ID	NOx limit, lb/hr	NOx limit, tpy
17A	18.5	81.0
18B	23.0	100.9
19A	23.0	100.9
25A	18.5	81
26A	18.5	81

DCP Midstream evaluated two control options for these combustion turbines: Solar's SoLoNOx combustion system and SCR.

1. Baseline Emissions for Units 17A, 18B, 19A, 25A, and 26A.

DCP Midstream did not provide any specific data on actual emissions for the Solar Centaur combustion turbines in its four-factor analysis of controls. The company did state that its cost effectiveness analyses for SoLoNOx and SCR were based on 2016 turbine operating hours multiplied by the permitted potential to emit rate (lb/hr).[125] However, the company did not provide the operating hours or this calculation of 2016 emissions in its four-factor analysis. The company also provided analyses of cost effectiveness of controls "[u]sing the actual emissions testing data (NSPS KKKK) for these turbines, rather than [potential to emit]."[126] Yet, the company provided no data in its four-factor analyses as to what the actual emission testing results were. Further confusing the matter is that, based on a review of the permit, the turbines are not subject to NSPS KKKK. Instead, all of the units except Unit 17A are subject to

[121] Title V Operating Permit P086-R3 for DCP Eunice Gas Plant at A6 to A7.
[122] *Id.*
[123] *Id.* at A10.
[124] *Id.* at A9.
[125] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Eunice Gas Plant at 3-10, fn 13.
[126] *Id.*

NSPS Subpart GG, and the Title V permit does not identify Unit 17A as subject to either NSPS Subpart GG or Subpart KKKK.[127] A review of Title V permit application data for the Eunice Gas Plant on the NMED's Emissions Analysis Tool did not find any other emissions testing data available for these units.[128]

NMED must make available whatever test data is being relied on to reflect actual emissions of these five combustion turbines if NMED intends to rely on the cost effectiveness analyses provided in a footnote of DCP Midstream's four-factor analysis. NMED should present information on the test data so the circumstances of the stack tests can be reviewed. According to DCP Midstream's four-factor analysis, its 2016 emission inventory is based on its actual operating hours multiplied by its hourly NOx emission limit.[129] Given that this is how DCP Midstream reports actual emissions for the combustion turbines to NMED and in the absence of testing documentation to ensure that the test data DCP relies on for its alternative baseline analysis reflects actual emissions at all levels of operation of the combustion turbines, it seems most appropriate to use the data that DCP has been using for its emission inventory. NMED should require that DCP identify the operating hours of each unit that it has assumed for the combustion turbines.

2. Evaluation of SoLoNOx for Turbines at Units 17A, 18B, 19A, 25A, and 26A.

DCP Midstream states that SoLoNOx can achieve an "overall reduction efficiency of 70-80%...for the turbines located at this facility using this technology in comparison to permitted [potential to emit]."[130] NMED should request that DCP Midstream identify the NOx rate that Solar Turbines guarantees for each of the five turbines at Eunice Gas Plant. Specifying a NOx emission rate that can be met with SoLoNOx also would provide for a clear benchmark for comparison to SCR.

Based on assuming 70 to 80% reduction with SoLoNOx from the permitted ppmv NOx emission limits, it appears that DCP Midstream evaluated SoLoNOx to achieve NOx emission rates in the range of 31 ppmv to 50 pppmv at 15% O_2 at Units 17A, 18B, 19A, 25A, and 26A.[131] These seem like high emission rates expected with SoLoNOx, based on a review of emission limit data for combustion turbines in the EPA's RACT/BACT/LAER Clearinghouse which indicates SoLoNOx limits in the range of 15-25 ppmv. As another comparison, Enterprise evaluated SoLoNOx for the Solar Mars turbines at the Chaco Gas Plant and stated that SoLoNOx could reduce NOx concentrations down to 15 ppmv. Although Section 8.0 of DCP Midstream's four-factor analysis

[127] Title V Operating Permit P086-R3 for DCP Eunice Gas Plant at A5, Table 103.A.
[128] While Section 8.0 of the four-factor analysis for the Eunice Gas Plant has specific baseline NOx emission rates for the Linam Ranch Gas Plant combustion turbines, it does not have baseline NOx rates for the Eunice Gas Plant combustion turbines.
[129] *Id.* at 3-11.
[130] *Id.* at 2-4.
[131] This range of controlled ppmv NOx emission rates is based on assuming 70 to 80% reduction from the 158.76 ppmv NOx emission limit that Units 17A, 25A, and 26A and from the 165.85 ppmv NOx limit that Units 18B and 19A are subject to.

has cost data sheets for SoLoNOx indicating a NOx guarantee from Solar of 15 ppm, those cost data sheets pertain to the Linam Ranch Gas Plant rather than for the combustion turbines at the Eunice Gas Plant. For these reasons as well as completeness of the four-factor analysis of emissions controls for these units, NMED must collect more specific information on the NOx emission rates that DCP Midstream used in its SoLoNOx cost effectiveness analysis for the combustion turbines.

In terms of the life of SoLoNOx controls in the cost effectiveness analyses, DCP's analysis assumed a 20-year life. For the reasons described above on the evaluation of dry low NOx combustors at the gas turbines at the Chaco Gas Plant, a 25-year life is a more appropriate assumption for the cost effectiveness analysis.[132] In the table below, we revised DCP Midstream's cost effectiveness analyses of SoLoNOx to take into account a longer lifetime of controls and a lower 4.7% interest rate.

Table 7. Revised Cost Effectiveness of SoLoNOx at Units 17A, 18B, 19A, 25A, and 26A of the DCP Midstream Eunice Gas Plant

Unit	DCP's Total Annual Costs of SoLoNOx (at 5.5% Interest and 20-Year Life)	DCP's Cost Effectiveness at 5.5% Interest and 20 Year Life	Revised Total Annual Costs of SoLoNOx	Revised Cost Effectiveness at 4.7% Interest and 25-Year Life
17A	$264,731	$4,909/ton	$244,277	$4,530/ton
18B	$264,154	$3,578/ton	$243,700	$3,301/ton
19A	$264,154	$3,618/ton	$243,700	$3,338/ton
25A	$264,731	$5,186/ton	$244,277	$4,785/ton
26A	$264,731	$6,005/ton	$244,277	$5,542/ton

Thus, the cost effectiveness of SoLoNOx at Units 17A, 18B, 19A, 25A, and 26A are in the range of $3,300/ton to $5,542/ton to achieve 70-80% NOx reduction. However, if SoLoNOx can achieve 15-25 ppmv NOx emission rates at these units as has been permitted for other Solar turbine units with SoLoNOx, and as has been proposed in several four-factor analyses before NMED, then the NOx removal expected with SoLoNOx would be 84 to 91% and the controls would be even more cost effective than shown in the above table. The table below provides an estimate of the cost effectiveness of SoLoNOx if the controls could achieve 25 ppmv (~85% control) and 15 ppmv (~90% control).

[132] *See also* NPCA March 2020 Oil and Gas Four-Factor Report at 69-70.

Table 8. Estimated Cost Effectiveness of SoLoNOx at Units 17A, 18B, 19A, 25A, and 26A of the DCP Midstream Eunice Gas Plant to Meet 25 ppmv NOx Rates and to Meet 15 ppmv NOx Rates.

Unit	Revised Total Annual Costs of SoLoNOx	Estimated NOx Reduced to Achieve 25 ppmv NOx Rate (~85% Reduction), tpy	Estimated NOx Reduced to Achieve 55 ppmv NOx Rate (~90% Reduction), tpy	Cost Effectiveness to Meet 15 to 25 ppmv NOx limit, $/ton
17A	$244,277	68.8	72.9	$3,352 - $3,549/ton
18B	$243,700	85.7	90.8	$2,684 - $2,842/ton
19A	$243,700	84.8	89.8	$2,714 - $2,874/ton
25A	$244,277	65.2	69.0	$3,541 - $3,749/ton
26A	$244,277	56.3	59.6	$4,100 - $4,341/ton

If SoLoNOx at Units 17A, 18B, 19A, 25A, and 26A of the DCP Midstream Eunice Gas Plant could meet more typical NOx limits with SoLoNOx of 15-25 ppmv, then the SoLoNOx controls would be even more cost effective than shown in DCP Midstream's four-factor analysis.

3. Evaluation of SCR for Units 17A, 18B, 19A, 25A, and 26A of the DCP Midstream Eunice Gas Plant.

Unlike Enterprise in its four-factor analysis of controls for the combustion turbines at the Chaco Gas Plant, DCP Midstream evaluated SCR as a technically feasible control option for the Solar Centaur gas combustion turbines of Units 17A, 18B, 19A, 25A, and 26A of the DCP Midstream Eunice Gas Plant. DCP Midstream used EPA's SCR cost spreadsheet made available with EPA's Control Cost Manual.[133] While the company presented printouts of the EPA SCR cost spreadsheet in Section 8.0 of its four-factor analysis, the printouts appear to be for the Linam Ranch Gas Plant and not the Eunice Gas Plant. NMED should request a printout of the pages of the SCR cost spreadsheet for Units 17A, 18B, 19A, 25A, and 26A of the Eunice Gas Plant so the inputs to the spreadsheet can be reviewed.

DCP Midstream only assumed 70% control could be achieved with SCR at Units 17A, 18B, 19A, 25A, and 26A, even though the company indicated that SCR could achieve up to 90% control.[134] As presented NPCA's Oil and Gas Four-Factor Report, NESCAUM assumed 90% control with SCR in its 2000 Status Report to control small gas turbines down to 15 ppmv.[135] Analyses of EPA's SCR cost spreadsheet for combustion turbines of similar size to Units 17A, 18B, 19A, 25A, and 26A shows that the spreadsheet's calculation of capital cost does not vary based on the NOx control efficiency assumed for the SCR, but that the direct operational expenses increase by

[133] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Eunice Gas Plant at 3-11.
[134] *Id.* at 2-6.
[135] NPCA March 2020 Oil and Gas Four-Factor Report at 74-75. *See also* NESCAUM, December 2000, Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, Technologies & Cost Effectiveness at III-21 through III-24 and at III-40 (see referenced 11, 16, 9, 14, and 15), available at http://www.nescaum.org/documents/nox-2000.pdf/view.

about 17.7%. Using this assumption, we revised DCP Midstream's SCR cost estimate to reflect the costs to achieve 90% NOx reduction, reflective of approximately a 15 ppmv NOx emission rate, along with using a longer life of the SCR of 25-years[136] and a 4.7% interest rate (instead of DCP's assumed 20-year life of SCR and 5.5% interest rate). The table below provides an estimated cost effectiveness of SCR to achieve 90% control at Units 17A, 18B, 19A, 25A, and 26A of the DCP Midstream Eunice Gas Plant.

Table 9. Estimated Cost Effectiveness of SCR to Achieve 90% Reduction (~15 ppmv NOx Rate) at Units 17A, 18B, 19A, 25A, and 26A (at 4.7% interest rate and 25-year life)

Eunice Gas Plant Unit #	DCP's Capital Cost of SCR	DCP's Annual Operational Costs of SCR[137]	Estimate of Revised DCP Annual Operational Costs of SCR to Reflect 90% Control[138]	Revised Annual Cost of SCR to Achieve 90% Control	NOx Emission Reductions at 90% Control, tpy	Cost Effectiveness of SCR to Achieve 90% Control
17A	$1,500,000	$149,435	$136,663	$239,914	72.87	$3,292/ton
18B	$1,500,000	$148,858	$138,195	$241,446	90.78	$2,660/ton
19A	$1,500,000	$148,858	$137,979	$241,230	89.79	$2,686/ton
25A	$1,500,000	$149,435	$135,696	$238,947	68.99	$3,463/ton
26A	$1,500,000	$149,435	$123,938	$227,189	59.58	$3,813/ton

A comparison of Table 9 to Tables 7 and 8 above shows that SCR at the Eunice Gas Plant Units 17A, 18B, 19A, 25A, and 26A is actually more cost effective than SoLoNOx at DCP's assumed 70-80% control or even assuming SoLoNOx can achieve 15 ppmv. SCR could be even more cost effective if there are opportunities to share an SCR between two or more combustion turbines. Moreover, SCR combined with SoLoNOx, which is commonly required to meet BACT for gas turbines, could reduce NOx by 97% or more. As discussed in Section I.C.2 of this report, this combination of NOx controls has been permitted for the Buckingham Compressor Station to achieve a NOx emission rates of 3.75 ppmv @ 15% oxygen.[139] However, emission rates with SoLoNOx and SCR at gas-fired combustion turbines could be even lower, as BACT or LAER for such turbines operated for power generation are generally set at 2 to 2.5 ppmv at 15%

[136] EPA's Control Cost Manual indicates that SCR at industrial units has a life of 25-years. *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80.
[137] This was calculated from DCP Midstream's Total Annual Cost of SCR by subtracting the product of DCP's capital cost of SCR and a cost recovery factor reflective of DCP's assumed 5.5% interest rate and 20-year life.
[138] Estimated by multiplying DCP's annual operational costs of SCR by a factor of 1.177.
[139] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.

oxygen.[140] NMED should require DCP Midstream to evaluate the cost effectiveness of the combination of SoLoNOx and SCR to achieve the greatest level of NOx reduction.

III. IACX Roswell – Bitter Lake Compressor Station

The IACX Roswell, LLC Bitter Lake Compressor Station is located 13 miles northeast of Roswell, New Mexico and identified by NMED as contributing to regional haze at the Salt Creek WA Class I area.[141] NMED has described the facility processes as follows:

> The function of the facility is to compress and dehydrate field natural gas for transport in underground pipelines, to extract natural gas liquids, and to recover helium.[142]

According to the permit, the plant includes two Cooper-Bessemer 2-stroke lean-burn RICE, a glycol dehydrator with two associated reboilers, a refrigeration unit, and three tanks.[143] In IACX's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Cooper-Bessemer 2SLB RICE GMVH-10C: Units C-891 and C-893.[144]

The selection of these two engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[145] The following provides a review of the company's four-factor analyses.

A. Units C-891 and C-893: Cooper-Bessemer GMVH-10C 2-Stroke Lean Burn RICE

Units C-891 and C-893 are two-stroke lean-burn RICE that were constructed in the 1980s, each with a capacity of 2,250 hp.[146] The units each have an hourly NOx limit of 20 lb/hr and an annual NOx limit of 87.6 tpy.[147] That is the extent of information provided on the actual NOx emissions from these units. NMED should request more information on the units' current hours of operation and actual NOx emissions.

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[140] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand and Curve Reset, at 9.
[141] November 2019 Regional Haze Four-Factor Analysis for IACX Roswell, LLC Bitter Lake Compressor Station at 3.
[142] Title V Operating Permit P047-R3 for Bitter Lake Compressor Station at A4.
[143] Title V Operating Permit P047-R3 for Bitter Lake Compressor Station at A6–A7.
[144] November 2019 Regional Haze Four-Factor Analysis for IACX Roswell, LLC Bitter Lake Compressor Station at 4.
[145] *Id.*
[146] Title V Operating Permit P047-R3 for Bitter Lake Compressor Station at A7.
[147] *Id.* at A8.

1. Use of Low Emission Combustion Technology

IACX claims that the Cooper-Bessemer GMVH-10C engines are currently operating with turbochargers and efficient combustion air intercoolers and describes these as "Clean Burn Technology (CBT)."[148] And IACX states that, "[b]ased on manufacturer guidance, the addition of these clean burn technologies allows the engines to range from 1.74 to 3.04 g/hp-hr, which allows for 25% to 57% reduction in NOx emissions; thus, no further assessment of these control practices is included in this report."[149] Yet, the permitted maximum hourly NOx emission rate of 20 lb/hr does not reflect the levels of NOx emissions claimed by IACX in its four-factor analysis. This hourly NOx emission rate is equivalent to 4 g/hp-hr for a 2,250 hp engine. A recent permit application supplied an uncontrolled NOx emission rate of 4 g/hp-hr, based on "engine manufacturer data."[150] This NOx emission level does not reflect the levels of NOx emissions achievable with LEC technology. In order to effectively evaluate a company's assessment of LEC a more precise definition of LEC technologies, and associated achievable emission rates, is needed.

NPCA's March 2020 Oil and Gas Four-Factor Report stated that a wide range of emission rates are achievable with LEC technology, with NOx emissions generally no higher than 2 g/hp-hr and often significantly lower (e.g., as low as 0.5 g/hp-hr).

For reference, the following additional sources of information regarding NOx emission rates specific to Cooper-Bessemer GMV model engines – both uncontrolled and with LEC technology – are provided here:

- EPA's 2000 RICE Update includes NOx emissions test data for specific engines, including Cooper-Bessemer GMV-10C, 2-stroke, lean-burn, 1,100 hp RICE retrofitted with LEC. Tested at 0.61 g/bhp-hr.[151]

- An evaluation by a technical group for the Pipeline Research Council International looked at three of the most representative make / models of 2-stroke lean-burn compressor engines: (1) 2,250 hp Cooper GMVH-10; (2) 2,000 hp Clark TLA-6; and (3) 2,500 hp Cooper GMW-10. According to a technical report by the OTC describing this evaluation, "[t]he evaluation concluded that there were no technology gaps and that each of the three makes/models evaluated were capable of attaining a NOx emissions limitation of 0.5 g/bhp-hr using a combination of improvements and retrofits related to air supply, fuel supply, ignition, electronic controls, and engine monitoring."[152]

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[148] November 2019 Regional Haze Four-Factor Analysis for IACX Roswell, LLC Bitter Lake Compressor Station at 7.
[149] *Id.*
[150] Bitter Lake Compressor Station permit application P047R3 (8/17/2016) Section 6, Page 2.
[151] EPA 2000 RICE Update at 4-8.
[152] Ozone Transport Commission, Technical Information, Oil and Gas Sector, Significant Stationary Sources of NOx Emissions, Final, October 17, 2012, p. 24, *available at*: https://otcair.org/upload/Documents/Meeting%20Materials/Final%20Oil%20%20Gas%20Sector%20TSD%2010-17-12.pdf [hereinafter referred to as "2012 OTC Report"].

EPA describes LEC retrofit kits designed to achieve extremely lean air-to-fuel ratios – in order to minimize NOx emissions – as encompassing the following retrofit technologies:

- Redesign of cylinder head and pistons to improve mixing (on smaller engines)
- Precombustion chamber (on larger engines)
- Turbocharger
- High energy ignition system
- Aftercooler
- Air-to-fuel ration controller (AFRC)[153]

So, in addition to the turbochargers and upgraded intercooler systems already employed at these Cooper-Bessemer engines, NMED should request that the company evaluate the cost effectiveness of retrofitting these engines with additional LEC technologies – e.g., precombustion chambers, high energy ignition systems, AFRCs, etc. – to further reduce NOx emissions from these engines– e.g., to achieve emission levels as low as 0.5 g/hp-hr. Without data on actual NOx emissions from these engines it's not possible to know if, in fact, the current "clean burn technologies" employed at these units are achieving the emission levels of 1.74 to 3.04 g/hp-hr (that are based on manufacturer guidance) identified in the company's four-factor analysis. NMED should ask for test data reflective of actual operations at maximum operating capacity and ensure that these emission rates are a reasonable projection of NOx emissions in 2028.

2. Use of SCR

IACX did not evaluate SCR for Units C-891 and C-893, primarily because it claimed that the two engines run on ongoing variable loads and an SCR system may not function effectively at variable loads.[154] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for these engines, particularly if it could achieve greater NOx emissions reductions from these units cost effectively.

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[153] EPA, Final Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Docket ID EPA-HQ-OAR-2015-0500-0508, Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance, August 2016, Appendix A at 5-3, *available at:* https://www.regulations.gov/document?D=EPA-HQ-OAR-2015-0500-0508 [hereinafter referred to as "2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls"].
November 2019 Regional Haze Four-Factor Analysis for IACX Roswell, LLC Bitter Lake Compressor Station at 7.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[155]

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[156] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[157] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

IV. Targa Eunice Gas Processing Plant

The Targa Midstream Services, LLC Eunice Gas Plant is a natural gas processing plant identified by NMED as potentially contributing to regional haze at the Carlsbad Caverns National Park Class I area.[158] NMED has described the facility processes as follows:

> The function of the facility is to receive field natural gas, perform dehydration and removal of carbon dioxide and hydrogen sulfide, and separate natural gas liquids (NGL). The products (natural gas and NGL) are compressed or pumped to sales pipelines for distribution.[159]

According to the permit, the plant includes 21 reciprocating internal combustion engines (RICE), two boilers, an amine still, three electric compressors, backup diesel generators, flares, glycol dehydrator sources, heaters, and storage tanks.[160] In Targa's four-factor submittal, the company evaluated air pollution controls for the following emission units:

- Clark 2SLB RICE BA-8: Units C-01, C-02, C-03, C-04, C-05, C-06, C-07, C-09

[155] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[156] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[157] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[158] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 1-1.
[159] Title V Operating Permit P109-R3 for Eunice Gas Processing Plant at A3.
[160] *Id.* at A7-A9.

- Clark 2SLB RICE HBA-8: Units C-10, C-11, C-12
- Clark 2SLB RICE HBA-T8: Unit C-13
- Wickes/Type A Boiler: Units B-01, B-02.[161]

The selection of these sources for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hr or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[162] The following provides a review of the company's four-factor analyses.

A. Units C-01 through C-07, C-09 through C-13: Clark Natural Gas-Fired 2-Stroke Lean-Burn RICE

Units C-01 through C-07 and C-09 are Clark BA-8 two-stroke lean-burn RICE that were constructed in 1984, each with a capacity of 1,200 hp.[163] Units C-01 through C-07 each have an hourly NOx limit of 53.6 lb/hr and an annual NOx limit of 234.8 tpy.[164] Unit C-09 is restricted to 500 hours per year operation and has an hourly NOx limit of 53.6 lb/hr and an annual NOx limit of 13.4 tpy.[165]

Units C-10 through C-12 are Clark HBA-8 two-stroke lean-burn RICE that were constructed in 1984, each with a capacity of 1,600 hp.[166] The units each have an hourly NOx limit of 77.2 lb/hr and an annual NOx limit of 19.3 tpy.[167] These units are restricted to 500 hr/yr operation.[168] Unit C-13 is a Clark HBA-T-8 two-stroke lean-burn RICE that was constructed in 1984, with a capacity of 2,050 hp.[169] This unit has an hourly NOx limit of 61.1 lb/hr and an annual NOx limit of 267.5 tpy.[170]

1. Evaluation of Baseline NOx Emissions

Targa's four-factor submittal includes unit-specific operating hours based on 2016 emission inventory calculations or based on permit limits of 500 hr/yr for some units (C-09 through C-12). Uncontrolled NOx emission rates (g/hp-hr) in Targa's original four-factor analysis are, for all but one unit, based on a single performance test conducted in July 2015. The NOx emission rate for the one unit without performance test data, Unit C-03, is noted as, "from client."[171] Targa's February 2020 Addendum includes a corrected uncontrolled NO_x emission rate for C-03,

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[161] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 2-7.
[162] *Id.* at 1-3.
[163] Title V Operating Permit P109-R3 for Eunice Gas Processing Plant at A7.
[164] *Id.* at A10.
[165] *Id.* and NSR Permits 067-M8R1.
[166] Title V Operating Permit P109-R3 for Eunice Gas Processing Plant at A7.
[167] *Id.* at A10.
[168] *Id*. at A12 and NSR Permits 067-M8R1 and 067-M7.
[169] Title V Operating Permit P109-R3 for Eunice Gas Processing Plant at A7.
[170] *Id.* at A11.
[171] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant. *See, e.g.,* Appendix B Unit C-03.

based on a 2015 performance test, of 14.192 g/hp-hr.[172] The actual emission rates for these units, based on the July 2015 testing, and the allowable NOx emission rates are shown in the table below.[173]

Table 10. Targa Eunice Gas Processing Plant 2SLB RICE Unit NOx Emission Rates

Unit	Size [hp]	NOx Permit Limit [lb/hr]	NOx Permit Limit [g/hp-hr]	NOx Actual Emissions from April 2015 Test Data [g/hp-hr]
C-01	1,200	53.6	20.3	13.165
C-02	1,200	53.6	20.3	9.226
C-03	1,200	53.6	20.3	14.192
C-04	1,200	53.6	20.3	11.742
C-05	1,200	53.6	20.3	9.285
C-06	1,200	53.6	20.3	13.261
C-07	1,200	53.6	20.3	13.787
C-09	1,200	53.6	20.3	17.249
C-10	1,600	77.2	21.9	11.401
C-11	1,600	77.2	21.9	16.265
C-12	1,600	77.2	21.9	9.838
C-13	2,050	61.1	13.5	13.654

As shown, the actual emission rates for most of these units—with the exception of unit C-13—are lower than these units' allowable NOx emission rates, with some less than 50% of allowable levels. So, either the 2015 performance test data was not conducted while the engines were operating at maximum capacity or the allowable NOx emission rates have been set unreasonably high. NMED should present information on the 2015 test data so the circumstances of the tests can be reviewed. Targa's February 2020 Addendum included the results from portable analyzer testing conducted over a few days in August 2016 for the engines at the Saunders Gas Plant, which presumably are the tests used in determining baseline emissions for the four-factor analysis for that source.[174] NMED and Targa should review performance tests based on EPA Reference Methods for the Eunice Gas Plant to ensure that the actual emission rates can be considered to truly reflect actual emissions over the lifetime of the controls being evaluated. Citing variability in test data, Targa admits that these data are only a snapshot in time and only provide potential emissions based on that snapshot.[175] If testing is only done sporadically and is not done using EPA Reference Methods then it is questionable that such test data truly

[172] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 7.
[173] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant Appendix B.
[174] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 18-62.
[175] *Id.* at pdf page 6.

reflect an accurate projection of emissions expected over the lifetime of the controls being evaluated.

According to the source's Title V permit application, the allowable NOx emissions for these units are based on performance test data. Specifically, in the April 2018 Title V renewal application for the Eunice Gas Processing Plant, permitted rates for units C-01 through C-07 and C-09 of 53.6 lb/hr (equivalent to 20 g/hp-hr) are based on "stack data."[176] Note, stack test-based emissions are included for units C-09 through C-11, which are from the 2008 Title V renewal application, and are more in line with the emission rates used in the four-factor analysis (i.e., the Title V application lists "stack test-based emissions" for unit C-09 of 44.6 lb/hr (16.9 g/hp-hr) and for units C-10 and C-11 of 60 lb/hr (17.0 g/hp-hr), compared to the emission rates in the four-factor analysis of 17.249, 11.401, and 16.265 g/hp-hr for units C-09, C-10, and C-11, respectively).[177] However, the "current permitted rates (based on stack data)" for Units C-01 through C-07 that are listed in Targa's 2018 Title V permit application are equivalent to 20 g/hp-hr and are significantly higher than the NOx emission rates that the company's four-factor cost effectiveness analysis is based upon, meaning NOx reductions estimates for the various control options considered may be underestimated. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on a more comprehensive estimate of emissions expected in 2028.

2. Use of Low Emission Combustion Technology

Targa describes the LEC control technologies for these 2SLB engines as "Clean Burn Technology (CBT)."[178] Targa determined that this LEC technology is a technically feasible option for the 2SLB RICE units at the Eunice Gas Plant and the cost analysis provided in its four-factor analysis indicates this control is cost effective, especially for the engines that operate without restriction (i.e., Units C-01 through C-07 and C-13). Despite this, Targa concludes these retrofits would be uneconomical.[179]

The cost analysis in Targa's four-factor submittal doesn't support this claim, and the cost effectiveness of controls may be even more favorable than what is presented by Targa.

In its original November 2019 submittal, Targa presents cost effectiveness of controls for units C-01 through C-07 and for unit C-13 that range from $900–$6,000 per ton. The capital cost estimates are based on "manufacturer specification" and the annual operating and maintenance costs were provided by Targa.[180] Note, these annual operating and maintenance costs are higher than what was provided by other companies for LEC retrofits for similar

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[176] *See* April 2018 Title V Permit Application for Eunice Gas Processing Plant at pdf page 50.
[177] *Id.* at 47 and 48.
[178] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 2-9.
[179] *Id.* at 7-1.
[180] *Id.* Appendix B. Note, Targa stated, on pdf page 8 of its February 2020 Addendum, that "the O&M cost included in the analyses were based on Targa's experience operating similar control devices at other sites for expected maintenance and repair."

engines.[181] Targa's February 2020 Addendum included a revised control cost analysis, with costs effectiveness ranging from $3,331–$121,892 per ton, based on much higher cost estimates, and based on higher controlled NOx emission rates.[182] The capital investment for the Clean Burn Technology in the original submittal totaled just under $1 million per engine, compared to over $5 million in the Addendum.[183] The original capital cost estimates are in line with other capital cost estimates for LEC controls at other similar engines, at less than $140/hp,[184] whereas the capital cost estimates in Targa's Addendum are significantly higher, at up to $400/hp. It appears that the revised costs include $3 million—per engine—for electrical power, which Targa indicated in its original submittal could cost between $1–$3 million but would require an engineering assessment in order to know the full cost of this upgrade.[185] Note, even without these electrical upgrades, the other capital costs reach over $200/hp which is still significantly higher than the Targa's original estimates of less than $140/hp.

In its original submittal Targa stated that the Clean Burn Technology upgrades would either include turbochargers or externally driven blowers, with the electrical upgrades only necessary if blowers are used.[186] Even assuming the need for blowers and the highest cost estimate for upgrading the electrical substation (i.e., $3 million instead of $1 million), the cost effectiveness of these LEC controls is as low as $3,300—$5,600/ton for frequently-operating engines.[187] Assuming the electrical upgrades would cost $1 million instead of $3 million or that electrical upgrades aren't needed would obviously result in much more favorable cost effectiveness of these controls.

Note that Targa's submittal for the Saunders Gas Plant includes an analysis of the exact same LEC controls for the 2SLB RICE at that facility—e.g., requiring turbochargers or externally driven blowers—and the capital costs for that analysis are in line with the original cost estimates for the Eunice Gas Plant, at <$140/hp. And Targa's February 2020 Addendum for the Eunice, Monument, and Saunders gas plants did not include higher cost estimates for increased electricity needs at the Saunders Gas Plant. It's true that there are on-site electrical generation capabilities at the Saunders Gas Plant (e.g., units G-01 through G-04) but Targa's analysis for this facility does not appear to reflect a measurable increase in capital cost expenditures

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[181] *See, e.g.,* November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant, which assumed O&M costs of $40,000/yr for Clark HRA-8 engines.

[182] *See* February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 7 and 83—95.

[183] Note, these original capital cost estimates are in line with other company analyses for similar engines, e.g., Harvest Four Corners Kutz Canyon Gas Processing Plant's analysis for Clark HBA-8 engines used capital cost estimates of $1,000,000. Also, EPA's 2000 RICE Update (p. 5-2) included capital cost estimates for third-party retrofit of a Clark Model HSRA, 2SLB 1,000 hp 8-cylindar engine at a pipeline station of $710,000.

[184] *See, e.g.*, November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant cost data for Clark engines at just under $140/hp.

[185] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 2-10 and 3-2.

[186] *Id.*

[187] E.g., cost effectiveness of C-13 at 7,560 hr/yr is $3,331/ton, C-06 at 8,123 hr/yr is $5,465/ton, C-03 at 7,275 hr/yr is $5,430/ton, C-01 at 8,009 hr/yr is $5,600/ton.

associated with the externally driven blowers that may be required at this site for LEC controls at the 2SLB RICE. And at any rate, any cost analysis associated with upgrades to a power substation that serves the Eunice Gas Plant should be considered separately, as part of a facility-wide assessment of the cost effectiveness of electrifying additional sources that could further reduce NOx emissions from the plant (e.g., electrification of additional engines).

In Targa's original submittal, its cost effectiveness analysis assumes controlled NOx emission rates of 2 g/hp-hr based on "information provided by the engine control vendor."[188] The corresponding NOx emissions reductions in Targa's original four-factor analysis for these units range from 61% to 88%.[189] Note, greater emissions reductions would result from control of units that are operating at levels closer to permitted levels (which are, again, based on test data for the units according to the source's Title V permit application) would mean that the LEC controls would be even more cost effective than what is shown in the original four-factor analysis. Targa specifically describes the control technology for these engines as able to reduce NOx emissions between 70% and 90%.[190] Subsequently, Targa's Addendum includes a new analysis of the cost effectiveness of reducing NOx emissions to levels of 4 g/hp-hr and 5 g/hp-hr, reflecting NOx emissions reductions of only 46–77%.[191]

In addition, as a result of assuming what could be unreasonably low NOx emission rates for current uncontrolled emissions from some of the 2SLB engines, i.e., emission rates based on performance test data that show much lower rates than the permitted limits for these units (that, according to Targa's Title V permit application, are based on stack data),[192] Targa then also potentially further underestimates the magnitude of potential NOx reductions for these units in its cost effectiveness analysis. The permitted hourly NOx emission rates, based on stack test data, are as follows: 20 g/hp-hr (units C-01 through C-07 and C-09); 23 g/hp-hr (units C-10 through C-12); and 14 g/hp-hr (unit C-13).[193] The permitted rate for unit C-13 is in line with the performance test data from 2015 used in the four-factor analysis but the other units' emission rates are significantly lower in the four-factor analysis than the stack test based rates in the source's Title V permit application. Therefore, the potential emissions reductions achieved by retrofitting units C-01 through C-07 and C-09 through C-12 could be much greater than what the four-factor analysis shows for these units. For uncontrolled permitted emission rates around 20 g/hp-hr, controlled rates of 2 g/hp-hr would achieve 90% reduction in NOx emissions.

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[188] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 3-3.
[189] *Id.* at Appendix B.
[190] *Id.*at 2-9.
[191] *See* February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 83—95.
[192] *See* April 2018 Title V Permit Application for Eunice Gas Processing Plant at pdf page 50.
[193] *Id.* at pdf pages 48-51.

With respect to the life assumed for LEC control, Targa assumed a 20-year period.[194] Targa appears to base this on EPA's guidance default for SCR.[195] It's possible that LEC controls can last 25 years, as stated in other cost effectiveness analyses submitted to NMED for LEC controls.[196]
Also, Targa uses an interest rate of 5.5% which is likely high and therefore underestimates annualized costs of control for these engines. As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.

Revising Targa's cost effectiveness analyses to address some of these issues, including assuming: 1) a 4.7% interest rate (instead of 5.5%), 2) a 25-year life of LEC (instead of an assumed 20-year life), and 3) emissions reductions of 90% based on potential operation at permitted levels (based on stack test data), improves the cost effectiveness of these controls even further, as shown in the table below. Note, this revised analysis uses Targa's original capital investment costs, since these are more in line with the cost analysis for its Saunders Gas Plant and with other capital cost estimates for LEC technology for similar engines; additional capital investments related to electrical capacity upgrades at the facility should be assessed, in more detail, as a separate broader analysis. Further note, this revised analysis assumes a slightly lower NOx emissions reductions estimate for unit C-13 of 85%, based on this unit's actual emission rate, since this emission rate is in line with permitted emissions for this unit.

[194] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant Appendix B.
[195] *Id.*
[196] *See* 2019 Four-Factor Analyses for Roswell Compressor No. 9 and Jal No. 3.

Table 11. Cost Effectiveness of LEC at Uncontrolled Eunice Gas Plant Units C-01 through C-07 and C-09 through C-13 to Reduce NO_x Levels to 2 g/hp-hr, Assuming 90% Reductions in NOx Emissions, at 4.7% Interest Rate, and a 25-Year Life of Controls, 2019 $

Unit	Size [hp]	Capital Cost of LEC to Reduce NOx from the Uncontrolled rate of 20 g/hp-hr	Annual O&M Costs	Total Annualized Costs of LEC to Reduce NOx to 2 g/hp-hr (90% NOx Reduction)	Annual Operating Hours, hr/yr	NOx Removed, tpy	Cost Effectiveness of LEC, $/ton
C-01	1,200	$950,000	$100,000	$165,392	8,009	191	$867/ton
C-02	1,200	$950,000	$100,000	$165,392	4,271	102	$1,626/ton
C-03	1,200	$950,000	$100,000	$165,392	7,275	173	$955/ton
C-04	1,200	$950,000	$100,000	$165,392	5,996	143	$1,159/ton
C-05	1,200	$950,000	$100,000	$165,392	7,684	183	$904/ton
C-06	1,200	$950,000	$100,000	$165,392	8,123	193	$855/ton
C-07	1,200	$950,000	$100,000	$165,392	6,476	154	$1,073/ton
C-09	1,200	$950,000	$100,000	$165,392	500*	12	$13,893/ton
C-10	1,600	$950,000	$100,000	$165,392	500*	16	$10,420/ton
C-11	1,600	$950,000	$100,000	$165,392	500*	16	$10,420/ton
C-12	1,600	$950,000	$100,000	$165,392	500*	16	$10,420/ton
C-13	2,050	$950,000	$100,000	$165,392	7,560	203**	$814/ton

* These units are limited to 500 hr/yr operation in NSR Permits 067-M8R1 and 067-M7.
** Emissions reductions for Unit C-13 are based on controlling NOx emissions from the unit's actual emission rate of 14 g/hp-hr to 2 g/hp-hr (i.e., assuming NOx emissions reductions of 85%, instead of the 90% reduction assumed for all other units).

In Targa's original submittal it specifically describes the LEC modifications for these engines as including pre-combustion chambers and fuel systems to significantly lean the combustion mixture.[197] And Targa notes that the modifications will, "need turbochargers or externally driven blowers added as well."[198] Regarding the possibility of externally driven blowers, Targa points out the following:

> If a 2SLB engine does need an externally driven blower, this will be an electric blower and require electricity to operate. At this time, Eunice Gas Plant would have to significantly upgrade the power substation at the plant to operate blowers associated with these controls. The cost provided in Section 3 of this report does not include the cost to upgrade the electrical substation at the facility. An engineering design assessment would need to be completed before a total cost for the upgrade can be provided but is estimated at $1 million to $3 million.

[197] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 2-9.
[198] *Id.* at 2-10.

> Even with the power concerns, Targa has determined that this method of NOX control is feasible for the 2SLB engines at the facility.[199]

In Targa's Addendum, it more specifically describes the technologies included in its updated analysis, including adding a pre-combustion chamber with power cylinder heads, modifications to the fuel system, adding a turbocharger system, and various upgrades to the intercooler system.[200]

As Targa acknowledges, it's not clear to what degree – and at what cost – additional upgrades to the power substation would be required. And Targa has stated that these LEC controls are feasible regardless of power concerns. So any claim that electrical power upgrades would render this control infeasible must be more carefully evaluated based on more specific data (e.g., energy needs in kW and the costs of those energy needs) in order to be able to assess the cost effectiveness of the additional electricity usage that would be required to power any blowers, or any other potential electrified sources, as determined from a full engineering assessment.

3. Use of SCR.

Targa did not evaluate SCR for these units, primarily because it claimed that, "most 2SLB engines have a poor air-to-fuel ratio that will not support the SCR control."[201] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for these engines, particularly because Targa does not consider LEC to be economical.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[202]

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[199] *Id.*

[200] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 7.

[201] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 2-11.

[202] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[203] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[204] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

B. Natural Gas-Fired Boilers (Units B-01 and B-02)

Targa also evaluated controls for the Units B-01 and B-02 natural gas-fired boilers. These boilers are Wickes Type A boilers, each with a permitted capacity of 100 MMBtu/hr that were manufactured in 1972.[205] The units each are subject to allowable NOx emission limits of 20.6 lb/hr and 90.0 tpy.[206]

Targa states that the two boilers already are using good combustion practices and have low NOx burners. Targa states that ultra-low NOx burners are available but would be technically infeasible at times for the Eunice Gas Processing Plant boilers because of the age of the boilers and the vendors' concerns with the higher Btu content of the fuel.[207] Targa also found SCR to be technically infeasible for the boiler claiming the significant power requirements would require the power at the plant to be significantly upgraded and redesigned. In addition, Targa found the selective non-catalytic reduction (SNCR) was not technically feasible due to concerns about how low loads will impact the temperature profile and optimal operating temperature of the control. Targa's dismissal of all three of these controls as technically infeasible only provides brief claims of technical infeasibility with no details specific to the Unit B-01 and B-02 boilers design or operation that make the particular control technically infeasible for the units. Further, issues of cost do not make a control technically infeasible. Instead, the costs of any requirements to alter a boiler to be able to operate with ultra-low NOx burners or to upgrade electricity to power SCR needs to be costed out and considered in the cost effectiveness analysis. NMED must require more information from Targa to exclude these controls as technically infeasible, particularly ultra-low NOx burners and SCR, especially given that Targa's

[203] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[204] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[205] 11/29/2019 Title V Operating Permit For Targa Eunice Gas Processing Plant at A7.
[206] *Id.* at A11.
[207] November 2019 Four-Factor Analysis for Targa Eunice Gas Processing Plant at 2-13.

research of RACT/BACT/LAER Clearinghouse entries shows that these controls are commonly required for natural gas-fired industrial boilers.[208]

The only NOx control evaluated by Targa for the boilers is flue gas recirculation (FGR). Targa assumed that FGR would reduce NOx to 45 ppm, which would be 50% control from the base NOx emissions rate of 90 ppm.[209] At least one boiler manufacturer, Cleaver Brooks, states that FGR is one of the more commonly used methods to reduce NOx emissions and that it can achieve up to 80% NOx reduction.[210] However, the cost effectiveness of the control was calculated by Targa to be between $16,000 to $19,000/ton.[211] Part of the reason for the high cost effectiveness is that Targa assumed only a 20 year life of controls and a 5.5% interest rate. FGR consists of recycling a portion of the flue gas from the stack to the burner windbox. The NOx reduction occurs due to the recirculated flue gas reducing combustion temperatures and because of lowering the oxygen content in the flame zone.[212] The life of FGR should be the same as the life of the boiler. Targa did not identify the remaining useful life of boilers B-01 and B-02, but the boilers have been in operation since 1972 or 47 years. The lifetime of a boiler is typically thought to be at least 30 years, and Targa did not give any indication of any end of life for the boilers. Thus, Targa should have assumed a 30-year life of FGR. Also, as previously discussed, a lower interest rate should have been used, no higher than 4.7%.

However, the other reason the cost effectiveness of FGR appears to be so high at Units B-01 and B-02 is because the 2016 annual baseline emissions relied on by Targa are very low compared to the units' allowable emissions (8.08 and 6.73 tpy compared to 90 tpy allowable emissions each for Units B-01 and B-02). Yet, a review of the 2016 hourly emissions of NOx compared to the annual emissions of NOx indicates that the boilers operate very close to 8,760 hours per year. If the boilers' NOx emissions are expected to continue to be as low as indicated by the 2016 emission inventory, it seems questionable that the emission limits applicable to these units are reflective of the existing good combustion practices and low NOx burners. NMED should reduce the emission limits to reflect the current NOx controls on the boilers. If the boiler NOx emissions in 2016 are anomalous and not reflective of future operations of the boilers in 2028, then NMED should require a revised cost effectiveness analysis based on a more realistic estimate of annual NOx emissions.

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[208] *Id.* at Appendix A.
[209] *Id.* at 3-3 and at Appendix B (pdf pages 35 and 36 of document).
[210] *See* Cleaver Brooks, Strategies to Reduce NOx Emissions, Tip Sheet: October 2014, available at http://cleaverbrooks.com/september/. *See also* W.C. Rouse & Son, Low NOx Without Flue Gas Recirculation, in which it is stated that for gas-fired boilers, FGR can achieve 75-80% NOx reduction, available at https://www.wcrouse.com/low-nox-without-flue-gas-recirculation/.
[211] *Id.* at Appendix B (pdf pages 35 and 36 of document).
[212] EPA, AP-42 Emission Factor Document, Natural Gas Combustion, at page 3.

V. Targa Monument Gas Plant

The Targa Midstream Services, LLC Monument Gas Plant is a natural gas processing plant identified by NMED as potentially contributing to regional haze at the Carlsbad Caverns National Park Class I area.[213] NMED has described the facility processes as follows:

> The function of the facility is to process natural gas through inlet separation, an amine system for acid gas removal (carbon dioxide and hydrogen sulfide), dehydration for water removal, and the separation of methane from natural gas liquids (NGL). The natural gas is delivered to sales pipelines, propane is transported offsite with pressurized tank trunks, and the separated condensate is loaded into tank trucks for transport offsite.[214]

According to the permit, the plant includes seven RICE units, a steam boiler, heaters, gas turbines, storage tanks, vapor recovery units, an amine unit, and flares.[215]

In Targa's four-factor submittal, the company evaluated air pollution controls for the following emission units:

- Clark 2SLB RICE RA-8 (800 hp): Units C-01, C-02
- Clark 2SLB RICE RA-6 (600 hp): Units C-04, C-05, C-06
- Clark 2SLB RICE HRA-8 (880 hp): Unit C-24
- Cooper-Bessemer GMVA-8 (1,100 hp): Unit C-28
- Amine Gas Treating Unit / Flare: Unit AM-01 / F-03.[216]

The selection of these sources for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hr or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[217] The following provides a review of the company's four-factor analyses for the engines listed above. The Amine Gas Treating Unit/Flare is addressed in Section XXIII further below.

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[213] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Monument Gas Plant at 1-1.
[214] Title V Operating Permit P110-R2M1 for Monument Gas Plant at A3.
[215] *Id.* at A5–A7.
[216] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant at 2-1.
[217] *Id.* at 1-3.

A. Units C-01, C-02, C-04 through C-06, C-24, and C-28: Natural Gas-Fired 2-Stroke Lean-Burn RICE

Units C-01 and C-02 are Clark RA-8 two-stroke lean-burn compressor engines that were constructed in 1956, each with a capacity of 800 hp.[218] These units each have an hourly NOx limit of 27.8 lb/hr and an annual NOx limit of 121.8 tpy.[219]

Units C-04 through C-06 are Clark RA-6 two-stroke lean-burn compressor engines that were also constructed in 1956, each with a capacity of 600 hp.[220] The three units each have an hourly NOx limit of 25.1 lb/hr and an annual NOx limit of 109.9 tpy.[221]

Unit C-24 is a Clark HRA-8 two-stroke lean-burn compressor engine that was constructed in 1969, with a capacity of 880 hp.[222] This unit has an hourly NOx limit of 41.9 lb/hr and an annual NOx limit of 183.5 tpy.[223]
Unit C-28 is a Cooper-Bessemer GMVA-8 two-stroke lean-burn compressor engine that was constructed in 1977, with a capacity of 1,100 hp.[224] This unit has an hourly NOx limit of 16.6 lb/hr and an annual NOx limit of 72.7 tpy.[225]

1. Evaluation of Baseline NOx Emissions

Targa's four-factor submittal includes unit-specific operating hours based on 2016 emission inventory calculations. Uncontrolled NOx emission rates (g/hp-hr) in Targa's original four-factor analysis are based on a single performance test conducted for each engine in April 2015. The actual emission rates for these units, based on this April 2015 testing, and the allowable NOx emission rates are shown in the table below.[226]

Table 12. Targa Monument Gas Plant 2SLB RICE Unit NOx Emission Rates

Unit	Size [hp]	NOx Permit Limit [lb/hr]	NOx Permit Limit [g/hp-hr]	NOx Actual Emissions from April 2015 Test Data [g/hp-hr]
C-01	800	27.8	15.8	11.9
C-02	800	27.8	15.8	9.8
C-04	600	25.1	19.0	9.9
C-05	600	25.1	19.0	8.4
C-06	600	25.1	19.0	11.4

[218] Title V Operating Permit P110-R2M1 for Monument Gas Plant at A6.
[219] *Id.* at A8.
[220] *Id.* at A6.
[221] *Id.* at A8.
[222] *Id.* at A6.
[223] *Id.* at A8.
[224] *Id.* at A6.
[225] *Id.* at A8.
[226] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant Appendix B.

Unit	Size [hp]	NOx Permit Limit [lb/hr]	NOx Permit Limit [g/hp-hr]	NOx Actual Emissions from April 2015 Test Data [g/hp-hr]
C-24	880	41.9	21.6	18.2
C-28	1,100	16.6	6.8	6.3

As shown, the actual emission rates for all units, with the exception of C-28, are much lower than the units' allowable hourly NOx emission rates so, either the 2015 test data for these units was not conducted while the engines were operating at maximum capacity or the allowable NOx emission rates for these units have been set unreasonably high. NMED should present information on the 2015 test data so the circumstances of the tests can be reviewed. Targa's February 2020 Addendum included the results from portable analyzer testing conducted over a few days in August 2016 for the engines at the Saunders Gas Plant, which presumably are the tests used in determining baseline emissions for the four-factor analysis for that source.[227] NMED and Targa should review performance tests at the Monument Gas Plant, that are based on EPA Reference Methods, to ensure that the actual emission rates can be considered to truly reflect actual emissions over the lifetime of the controls being evaluated. Citing variability in test data, Targa admits that these data are only a snapshot in time and only provide potential emissions based on that snapshot.[228] If testing is only done sporadically and is not done using EPA Reference Methods then it is questionable that such test data truly reflect an accurate projection of emissions expected over the lifetime of the controls being evaluated.

According to the August 2018 Title V renewal application for the Monument Gas Plant, NOx emissions were determined, "based on stack test data with a safety factor..."[229] The permitted rates for these units (with the exception of unit C-28)—that are based on stack test data—are significantly higher than the NOx emission rates that the company's four-factor cost effectiveness analysis is based upon, meaning NOx reductions estimates for the various control options considered may be underestimated. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on a more comprehensive estimate of emissions expected in 2028.

2. Use of Low Emission Combustion Technology

Targa describes the LEC control technologies for these 2SLB engines as "Clean Burn Technology (CBT)."[230] According to EPA, "[t]he term "clean-burn" technology is a registered trademark of Cooper Energy Systems and refers to engines designed to reduce NOx by operating at high air-to-fuel ratios."[231] In Targa's original submittal it specifically describes the LEC modifications for

[227] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 18-62.
[228] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 6.
[229] *See* August 2018 Title V Permit Application for Monument Gas Plant at pdf page 36.
[230] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant at 2-3.
[231] EPA AP-42 Chapter 3, Section 3.2 (July 2000) at 3.2-2.

these engines as including pre-combustion chambers and fuel systems to significantly lean the combustion mixture.[232] And Targa notes that the modifications will, "need turbochargers or externally driven blowers added as well."[233] In Targa's February 2020 Addendum, it more specifically describes the technologies included in its updated analysis, including adding a pre-combustion chamber with power cylinder heads, modifications to the fuel system, adding a turbocharger system, and various upgrades to the intercooler system.[234]

Targa determined that this LEC technology is a technically feasible option for the 2SLB RICE units at the Monument Gas Plant and the cost analysis provided in its four-factor analysis indicates this control could be cost effective for some of these units (e.g., Unit C-24). Despite this, Targa concludes the following:

> However, retrofitting with these technologies would require Targa to spend significant amounts of time (for design and installation) and capital. In addition, based on the predominant wind direction and that SO_2, not NOx, is the contaminant of interest for visibility impairment in Carlsbad Caverns, NOx emissions from these pieces of equipment are inconsequential for regional haze purposes. Thus, retrofitting the Monument Gas Plant engines would be uneconomical and unnecessary for improving visibility.[235]

In terms of being uneconomical, the cost analysis in Targa's four-factor submittal doesn't necessarily support this claim for all engines, and more importantly, the cost effectiveness of controls may be even more favorable than what is presented by Targa.

In its original November 2019 submittal, Targa presents cost effectiveness of controls for these units that range from $1,688–$33,892 per ton. The capital cost estimates are based on "manufacturer specification" and the annual operating and maintenance costs were provided by Targa.[236] Note, these annual operating and maintenance costs are higher than what was provided by other companies for LEC retrofits for similar engines.[237] Targa's February 2020 Addendum included a revised control cost analysis, with costs effectiveness ranging from $6,398–$155,568 per ton, based on much higher cost estimates, and based on higher controlled NOx emission rates.[238] The capital investment for the Clean Burn Technology in the original submittal totaled $900,000 per engine, compared to over $5 million in the

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[232] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant at 2-4.
[233] *Id*.
[234] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 7.
[235] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant at 7-1.
[236] *Id.* Appendix B. Note, Targa stated, on pdf page 8 of its February 2020 Addendum, that "the O&M cost included in the analyses were based on Targa's experience operating similar control devices at other sites for expected maintenance and repair."
[237] *See, e.g.,* November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant, which assumed O&M costs of $40,000/yr for Clark HRA-8 engines.
[238] *See* February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 7 and 96–102.

Addendum.[239] The original capital cost estimates are high, at $150—$270/hp, compared to other capital cost estimates for LEC controls at other similar engines.[240] The capital cost estimates in Targa's Addendum are significantly higher, at over $750/hp for some units (e.g., C-04 through C-06). It appears that the revised costs include $3 million for electrical power, which Targa indicated in its original submittal could cost between $1–$3 million but would require an engineering assessment in order to know the full cost of this upgrade.[241] Note, even without these electrical upgrades, the other capital costs come in at over $400/hp for some units, which is still significantly higher than the $/hp figures in Targa's original submittal.

In its original submittal, Targa stated that the Clean Burn Technology upgrades would either include turbochargers or externally driven blowers, with the electrical upgrades only necessary if blowers are used.[242] Even assuming the need for blowers and the highest cost estimate for upgrading the electrical substation (i.e., $3 million instead of $1 million), the cost effectiveness of these LEC controls is as low as $6,398/ton for unit C-24.[243] Assuming the electrical upgrades would cost $1 million instead of $3 million, or that electrical upgrades aren't needed would obviously result in much more favorable cost effectiveness of these controls.

Note that, Targa's submittal for the Saunders Gas Plant includes an analysis of the exact same LEC controls for the 2SLB RICE at that facility—e.g., requiring turbochargers or externally driven blowers—and the capital costs for that analysis are, generally, less than $140/hp. And Targa's February 2020 Addendum for the Eunice, Monument, and Saunders gas plants did not include higher cost estimates for increased electricity needs at the Saunders Gas Plant. It's true that there are on-site electrical generation capabilities at the Saunders Gas Plant (e.g., units G-01 through G-04) but Targa's analysis for this facility does not appear to reflect a measurable increase in capital cost expenditures associated with the externally driven blowers that may be required at this site for LEC controls at the 2SLB RICE. And at any rate, any cost analysis associated with upgrades to a power substation that serves the Monument Gas Plant should be considered separately, as part of a facility-wide assessment of the cost effectiveness of electrifying additional sources that could further reduce NOx emissions from the plant (e.g., electrification of engines).

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[239] Note, these original capital cost estimates are in line with other company analyses for similar engines, e.g., Harvest Four Corners Kutz Canyon Gas Processing Plant's analysis for Clark HBA-8 engines used capital cost estimates of $1,000,000. Also, EPA's 2000 RICE Update (p. 5-2) included capital cost estimates for third-party retrofit of a Clark Model HSRA, 2SLB 1,000 hp 8-cylindar engine at a pipeline station of $710,000.

[240] *See, e.g.,* Four-Factor analyses for Chaco Gas Plant (Clark 2SLB RICE at $140/hp), Saunders Gas Plant (Cooper-Bessemer 2SLB RICE at $90-$138/hp), Roswell Compressor Station No. 9 (Cooper-Bessemer 4SLB RICE at $90/hp), Jal No. 3 (Cooper-Bessemer 2SLB RICE at $123/hp).

[241] November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Monument Gas Plant at 2-4 and 3-2.

[242] *Id.*

[243] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 101.

The annual hours of operation for these engines varies significantly. According to Targa's submittal, the annual hours of operation used in the four-factor analysis are based on 2016 emission inventory data, as shown in the table below:

Table 13. Targa Monument Gas Plant 2SLB RICE Units Annual Operation

Unit	Size [hp]	Hours of Operation From 2016 EI Calculations [hr/yr]
C-01	800	2,357
C-02	800	4,069
C-04	600	990
C-05	600	2,035
C-06	600	3,938
C-24	880	6,610
C-28	1,100	573
AVERAGE		2,939

In Targa's Addendum, it indicated that annual hours of operation depend on various factors—e.g., including whether units are working, when they require maintenance, etc. —and will vary each year from engine to engine but, overall, are generally uniform.[244] According to Targa, "each year the engines will operate with different hours of operation and fuel usage."[245] NMED should request operation data for additional years for these units in order to be able to better assess the cost effectiveness of controls for operating schedules that reflect the full range of usage for these engines.

In Targa's original submittal, its cost effectiveness analysis assumes controlled NOx emission rates of 2 g/hp-hr based on "information provided by the engine control vendor."[246] The corresponding NOx emissions reductions in Targa's original four-factor analysis for these units range from 68.3% to 89%.[247] Note, greater emissions reductions would result from control of units that are operating at levels closer to permitted levels (which are, again, based on test data for the units according to the source's Title V permit application) would mean that the LEC controls would be even more cost effective than what is shown in the original four-factor analysis. Targa specifically describes the control technology for these engines as able to reduce NOx emissions between 70% and 90%.[248] Subsequently, Targa's Addendum includes a new analysis of the cost effectiveness of reducing NOx emissions to levels of 4 g/hp-hr and 5 g/hp-hr, reflecting NOx emissions reductions of only 37–78%.[249]

[244] *Id.* at 6.
[245] *Id.* at 6.
[246] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant at 3-2.
[247] *Id.* at Appendix B.
[248] *Id.*at 2-4.
[249] *See* February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 96—102.

In addition, as a result of assuming what could be unreasonably low NOx emission rates for current uncontrolled emissions from some of the 2SLB engines, i.e., emission rates based on performance test data that show much lower rates than the permitted limits for these units (that, according to Targa's Title V permit application, are based on stack data), Targa then also potentially further underestimates the magnitude of potential NOx reductions for these units in its cost effectiveness analysis. The permitted hourly NOx emission rates, based on stack test data, are notably higher than the actual emission rates used in the four-factor analysis for all but unit C-28, as shown in the table in the previous section.[250] Therefore, the potential emissions reductions achieved by retrofitting these units could be much greater than what the four-factor analysis shows due to potential underestimated baseline emissions, hours of operation, and emissions reductions. For uncontrolled permitted emission rates ranging from 15.8—21.6 g/hp-hr, controlled rates of 2 g/hp-hr would achieve 87—91% reduction in NOx emissions.

With respect to the life assumed for LEC control, Targa assumed a 20-year period.[251] Targa appears to base this on EPA's guidance default for SCR.[252] It's possible that LEC controls can last 25 years, as stated in other cost effectiveness analyses submitted to NMED for LEC controls.[253]
Also, Targa uses an interest rate of 5.5% which is likely high and therefore underestimates annualized costs of control for these engines. As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.

Revising Targa's cost effectiveness analyses to address some of these issues, including assuming 1) a 4.7% interest rate (instead of 5.5%), 2) a 25-year life of LEC (instead of an assumed 20-year life), and 3) emissions reductions of 87—91% based on potential operation at permitted levels (based on stack test data), improves cost effectiveness of these controls even further, as shown in the table below. Note, this revised analysis uses Targa's original capital investment costs, since these are more in line with the cost analysis for its Saunders Gas Plant and with other capital cost estimates for LEC technology for similar engines; additional capital investments related to electrical capacity upgrades at the facility should be assessed, in more detail, as a separate broader analysis. Further note, this revised analysis assumes a NOx emissions reduction estimate for unit C-28 of just over 70%, based on this unit's actual emission rate, since this emission rate is in line with permitted emissions for this unit.

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[250] *Also see* August 2018 Title V Permit Application for Monument Gas Plant at pdf pages 44–47.
[251] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant Appendix B.
[252] *Id.*
[253] See 2019 Four-Factor submittals for Roswell Compressor Station and Jal No. 3 which both assume 25-year life of controls for LEC.

Table 14. Cost Effectiveness of LEC at Uncontrolled Monument Gas Plant Units C-01, C-02, C-04 through C-06, C-24, and C-28 to Reduce NO_x Levels to 2 g/hp-hr, Assuming 87—91% Reductions in NOx Emissions, a 4.7% Interest Rate, and a 25-Year Life of Controls

Unit	Size [hp]	Capital Cost of LEC to Reduce NOx from an Uncontrolled Rate [2019$]	Annual O&M Costs [2019$]	Total Annualized Costs of LEC to Reduce NOx to 2 g/hp-hr (87—91% NOx Reduction) [2019$]	Annual Operating Hours, hr/yr	NOx Removed, tpy	Cost Effectiveness of LEC [2019$], $/ton
C-01	800	$900,000	$100,000	$161,951	2,357	29	$5,661/ton
C-02	800	$900,000	$100,000	$161,951	4,069	49	$3,279/ton
C-04	600	$900,000	$100,000	$161,951	990	11	$14,570/ton
C-05	600	$900,000	$100,000	$161,951	2,035	23	$7,088/ton
C-06	600	$900,000	$100,000	$161,951	3,938	44	$3,663/ton
C-24	880	$900,000	$100,000	$161,951	6,610	126	$1,289/ton
C-28	1,100	$850,000	$100,000	$158,509	573	3	$47,086/ton*

* Emissions reductions for Unit C-28 are based on controlling NOx emissions from the unit's actual emission rate of 6.8 g/hp-hr to 2 g/hp-hr (i.e., assuming NOx emissions reductions of just over 70%), since this uncontrolled emission rate is in line with permitted emissions for this unit.
Capital costs for C-28 are listed as $850,000 based on manufacturer specification.

The cost effectiveness of LEC control could be significantly lower than what is shown above for engines that operate more frequently than in 2016. Targa stated, in its February 2020 Addendum, that "[w]ith regards to the engine usage, Targa attempts to use its engines uniformly but this does not mean equally on a calendar year basis."[254] An analysis that assumes each engine operates at the average annual operation of all engines in 2016, which is roughly 3,000 hours per year, e.g., would lower the cost effectiveness of Unit C-01 to $5,080/ton, units C-04 and C-05 to $5,491/ton each, and unit C-28 to $10,226/ton.

Regarding the possibility of externally driven blowers that would require electrical upgrades, Targa points out the following:

> If a 2SLB engine does need an externally driven blower, this will be an electric blower and require electricity to operate. At this time, Eunice Gas Plant would have to significantly upgrade the power substation at the plant to operate blowers associated with these controls. The cost provided in Section 3 of this report does not include the cost to upgrade the electrical substation at the facility. An engineering design assessment would need to be completed before a total cost for the upgrade can be provided but is estimated at $1 million to $3 million.

[254] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 6.

> Even with the power concerns, Targa has determined that this method of NOX control is feasible for the 2SLB engines at the facility.[255]

As Targa acknowledges, it's not clear to what degree – and at what cost – additional upgrades to the power substation would be required. And Targa has stated that these LEC controls are feasible regardless of power concerns. So any claim that electrical power upgrades would render this control infeasible must be more carefully evaluated based on more-specific data (e.g., energy needs in kW and the costs of those energy needs) in order to be able to assess the cost effectiveness of the additional electricity usage that would be required to power any blowers, or any other potential electrified sources, as determined from a full engineering assessment.

3. Use of SCR.

Targa did not evaluate SCR for these units, primarily because it claimed that, "most 2SLB engines have a poor air-to-fuel ratio that will not support the SCR control."[256] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for these engines, particularly because Targa does not consider LEC to be economical.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[257]

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[258] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost

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[255] *Id.*
[256] November 2019 Regional Haze Four-Factor Analysis for Targa – Monument Gas Plant at 2-5.
[257] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[258] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.

Manual[259] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

VI. Targa Saunders Gas Plant

The Targa Midstream Services, LLC Saunders Gas Plant is a natural gas processing plant identified by NMED as potentially contributing to regional haze at the Salt Creek Wilderness Area Class I area.[260] NMED has described the facility processes as follows:

> The function of the facility is to process natural gas, including dehydration and sweetening sour natural gas (removing sulfur and CO_2), and also remove lighter hydrocarbons (such as ethane and methane) from the inlet gas stream. The facility is capable of processing approximately 100 MMscf/d of gas.[261]

According to the permit, the plant includes nine two-stroke reciprocating internal combustion engines (RICE) used for compression, four 4-stroke generator RICE, an emergency generator, heaters, sulfur recovery unit and incinerator, storage tanks, an amine unit, and flares.[262] In Targa's four-factor submittal, the company evaluated air pollution controls for the following emission units:

- Cooper-Bessemer 2SLB RICE GMVA-10 (1,350 hp): Units C-01 through C-06
- Cooper-Bessemer 2SLB RICE GMV-10 (1,195 hp): Units C-07 and C-08
- Cooper-Bessemer GMVC-10 (1,800 hp): Unit C-09
- Ingersoll-Rand 4SRB RICE PKVG-8 (780 hp): Units G-01, G-02, G-03
- Amine Gas Treating Unit with Sulfur Recovery Unit and Incinerator: Unit AM-01 / I-01.[263]

The selection of these sources for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hr or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[264] The following provides a review of the company's

[259] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[260] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant at 1-1.
[261] Title V Operating Permit P111-R2M2 for Saunders Gas Plant at A3.
[262] *Id.* at A6–A7.
[263] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant at 2-1.
[264] *Id.* at 1-3.

four-factor analyses for the engines listed above. Comments on the four-factor analysis for the amine gas treating unit are provided in Section XXIII further below.

A. Units C-01 through C-09: Natural Gas-Fired 2-Stroke Lean-Burn RICE

Units C-01 through C-06 are Cooper-Bessemer GMVA-10 2-stroke lean-burn compressor engines that were constructed in 1953, each with a capacity of 1,350 hp.[265] These units each have an hourly NOx limit of 32.6 lb/hr and an annual NOx limit of 142.8 tpy.[266]

Units C-07 and C-08 are Cooper-Bessemer GMV-10 2-stroke lean-burn compressor engines that were also constructed in 1953, each with a permitted capacity of 1,195 hp.[267] The two units each have an hourly NOx limit of 28.7 lb/hr and an annual NOx limit of 125.6 tpy.[268]

Unit C-09 is a Cooper-Bessemer GMVC-10 2-stroke lean-burn compressor engine that was constructed in 1953, with a capacity of 1,800 hp.[269] This unit has an hourly NOx limit of 43.2 lb/hr and an annual NOx limit of 189.2 tpy.[270]

1. Evaluation of Baseline NOx Emissions

Targa's four-factor submittal includes unit-specific operating hours based on 2016 emission inventory calculations. Uncontrolled NOx emission rates (g/hp-hr) in Targa's original four-factor analysis are based on a single performance test conducted for each engine in August 2016. The actual emission rates for these units, based on this August 2016 testing, and the allowable NOx emission rates are shown in the table below.[271]

Table 15. Targa Saunders Gas Plant 2SLB RICE Unit NOx Emission Rates

Unit	Size [hp]	NOx Permit Limit [lb/hr]	NOx Permit Limit [g/hp-hr]	NOx Actual Emissions from August 2016 Test Data [g/hp-hr]
C-01	1,350	32.6	11.0	2.05
C-02	1,350	32.6	11.0	10.78
C-03	1,350	32.6	11.0	4.99
C-04	1,350	32.6	11.0	3.87
C-05	1,350	32.6	11.0	7.21
C-06	1,350	32.6	11.0	8.3

[265] Title V Operating Permit P111-R2M2 for Saunders Gas Plant at A6.
[266] *Id.* at A9.
[267] *Id.* at A7. Note, Unit C-08 has a maximum capacity of 1,350 hp and a permitted capacity of 1,195 hp.
[268] *Id.* at A9.
[269] *Id.* at A7.
[270] *Id.* at A9.
[271] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant Appendix B.

Unit	Size [hp]	NOx Permit Limit [lb/hr]	NOx Permit Limit [g/hp-hr]	NOx Actual Emissions from August 2016 Test Data [g/hp-hr]
C-07	1,195	28.7	10.9	7.35
C-08	1,195	28.7	10.9	9.13
C-09	1,800	43.2	10.9	5.54

As shown, the actual emission rates for most units, with the exception of C-02 and a few others, are much lower than the units' allowable hourly NOx emission rates, so either the 2016 testing for these units was not conducted while the engines were operating at maximum capacity or the allowable NOx emission rates for these units have been set unreasonably high. Targa's February 2020 Addendum included the results from portable analyzer testing conducted over a few days in August 2016 for the engines at the Saunders Gas Plant, which presumable are the tests used in determining baseline emissions for the four-factor analysis.[272] NMED and Targa should review other performance tests, that are based on EPA Reference Methods, for these units to ensure that the actual emission rates can be considered to truly reflect actual emissions over the lifetime of the controls being evaluated. Citing variability in test data, Targa admits that these data are only a snapshot in time and only provide potential emissions based on that snapshot.[273] If testing is only done sporadically and is not done using EPA Reference Methods then it is questionable that such test data truly reflect an accurate projection of emissions expected over the lifetime of the controls being evaluated.

According to the September 2018 Title V renewal application for the Saunders Gas Plant, NOx emissions for units C-01 through C-07 were," calculated using stack test data from 2/22/1994 with a 20% safety factor."[274] Note, permitted emission rates for units C-08 and C-09 were calculated using EPA AP-42 emission factors (Table 3.2-2).[275] The permitted rates for these units (with the exception of unit C-02, but especially for units C-01, C-03, and C-04)—that are based on stack test data—are significantly higher than the NOx emission rates that the company's four-factor cost effectiveness analysis is based upon, even considering the 20% "safety factor", meaning NOx reductions estimates for the various control options considered for these units may be underestimated. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on a more comprehensive estimate of emissions expected in 2028.

1. Use of Low Emission Combustion Technology

Targa describes the LEC control technologies for these 2SLB engines as "Clean Burn Technology (CBT)."[276] In Targa's original submittal it specifically describes the LEC modifications for these

[272] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 18-62.
[273] *Id.* at pdf page 6.
[274] *See* September 2018 Title V Permit Application for Saunders Gas Plant at pdf page 38.
[275] *Id.*
[276] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant at 2-7.

engines as including pre-combustion chambers and fuel systems to significantly lean the combustion mixture.[277] And Targa notes that the modifications will, "need turbochargers or externally driven blowers added as well."[278] In Targa's February 2020 Addendum, it more specifically describes the technologies included in its updated analysis, including adding a pre-combustion chamber with power cylinder heads, modifications to the fuel system, adding a turbocharger system, and various upgrades to the intercooler system.[279]

Targa determined that this LEC technology is a technically feasible option for the 2SLB RICE units at the Saunders Gas Plant and the cost analysis provided in its four-factor analysis indicates this control could be cost effective for these units, depending on the baseline emission rates and operating schedules. Despite this, Targa concludes these retrofits would be uneconomical.[280]

The cost analysis in Targa's four-factor submittal doesn't necessarily support this claim for these engines, and more importantly, the cost effectiveness of controls may be even more favorable than what is presented by Targa.

In its original November 2019 submittal, Targa presents cost effectiveness of controls for these units that range from $2,754–$277,724 per ton.[281] The capital cost estimates are based on "manufacturer specification" and the annual operating and maintenance costs were provided by Targa.[282] Targa's February 2020 Addendum included an additional control cost analysis based on higher controlled NOx emission rates; Targa also specified that the capital control cost estimates include engineering costs (e.g., equipment / installation, structural, drawings, etc.).[283] The capital cost estimates are similar, at $80—$138 per hp, compared to other capital cost estimates for LEC controls at other similar engines.[284]

The annual hours of operation for these engines varies quite a bit. According to Targa's submittal, the annual hours of operation used in the four-factor analysis are based on 2016 emission inventory data, as shown in the table below:

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[277] *Id.*
[278] *Id*.
[279] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 7.
[280] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant at 7-1.
[281] *Id.* at 3-2. Note, the $277,724/ton figure for unit C-01 represents the cost effectiveness of reducing NOx emissions from a baseline level for this unit (based on a single performance test from 2016) of 2.04 g/hp-hr to a controlled emission rate of 2 g/hp-hr; if this unit were operating at its permitted emission rate (that is also based on performance testing, from 1994) the cost effectiveness of this control would be *significantly* lower (i.e., <$2,000/ton).
[282] *Id.* Appendix B. Note, Targa stated, on pdf page 8 of its February 2020 Addendum, that "the O&M cost included in the analyses were based on Targa's experience operating similar control devices at other sites for expected maintenance and repair."
[283] *See* February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf pages 7 and 114–122.
[284] *See, e.g.,* Four-Factor analyses for Roswell Compressor Station No. 9 (Cooper-Bessemer 4SLB RICE at $90/hp) and Jal No. 3 (Cooper-Bessemer 2SLB RICE at $123/hp).

Table 16. Targa Saunders Gas Plant 2SLB RICE Units Annual Operation

Unit	Size [hp]	Hours of Operation From 2016 EI Calculations [hr/yr]
C-01	1,350	8,656
C-02	1,350	4,971
C-03	1,350	5,321
C-04	1,350	7,770
C-05	1,350	5,431
C-06	1,350	1,910
C-07	1,195	5,622
C-08	1,195	2,948
C-09	1,800	5,989

In Targa's Addendum, it indicated that annual hours of operation depend on various factors—e.g., including whether units are working, when they require maintenance, etc.—and will vary each year. According to Targa, "each year the engines will operate with different hours of operation and fuel usage."[285] NMED should request operation data for additional years for these units in order to be able to better assess the cost effectiveness of controls for operating schedules that reflect the full range of usage for these engines.

In Targa's original submittal, its cost effectiveness analysis assumes controlled NOx emission rates of 2 g/hp-hr based on "information provided by the engine control vendor."[286] The corresponding NOx emissions reductions in Targa's four-factor analysis for these units range from 2.4% to 81.4%.[287] Note, greater emissions reductions would result from control of units that are operating at levels closer to permitted levels (which are, again, based on test data for Units C-01 through C-07 according to the source's Title V permit application) would mean that the LEC controls would be even more cost effective than what is shown in the original four-factor analysis. And, in fact, Targa states that "[t]he Clean Burn technology will reduce NOx emissions by 81%."[288] For uncontrolled permitted emission rates of 11 g/hp-hr, controlled rates of 2 g/hp-hr would achieve an 81% reduction in NOx emissions, which is exactly what the Clean Burn technology is promising to achieve for all of these units.

As a result of assuming what could be unreasonably low NOx emission rates for baseline uncontrolled emissions from some of the 2SLB engines, i.e., emission rates based on performance test data that show much lower rates than the permitted limits for these units

[285] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 6.
[286] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant at 3-2.
[287] *Id.* at Appendix B.
[288] *Id.*at 2-7.

(that, according to Targa's Title V permit application, are based on stack data for all units but C-08 and C-09), Targa then also potentially further underestimates the magnitude of potential NOx reductions for these units in its cost effectiveness analysis. Therefore, the potential emissions reductions achieved by retrofitting these units could be much greater than what the four-factor analysis shows due to potential underestimated baseline emissions, hours of operation, and emissions reductions.

With respect to the life assumed for LEC control, Targa assumed a 20-year period.[289] Targa appears to base this on EPA's guidance default for SCR.[290] It's possible that LEC controls can last 25 years, as stated in other cost effectiveness analyses submitted to NMED for LEC controls.[291]
Also, Targa uses an interest rate of 5.5% which is likely high and therefore underestimates annualized costs of control for these engines. As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.

Revising Targa's cost effectiveness analyses to address some of these issues, including assuming 1) a 4.7% interest rate (instead of 5.5%), 2) a 25-year life of LEC (instead of an assumed 20-year life), and 3) emissions reductions of 81% based on potential operation at permitted levels (largely based on stack test data), improves cost effectiveness of these controls even further, as shown in the table below. Note, this revised analysis reflects the large range in operating hours, based on 2016 data, which may not be representative of individual engine usage in other years.

Table 17. Cost Effectiveness of LEC at Uncontrolled Saunders Gas Plant Units C-01 through C-09 to Reduce NO_x Levels to 2 g/hp-hr, Assuming 81% Reductions in NOx Emissions, a 4.7% Interest Rate, and a 25-Year Life of Controls, 2019 $

Unit	Size [hp]	Capital Cost of LEC to Reduce NOx from a Permitted Rate of 11 g/hp-hr	Annual O&M Costs	Total Annualized Costs of LEC to Reduce NOx to 2 g/hp-hr (81% NOx Reduction)	Annual Operating Hours, hr/yr	NOx Removed, tpy	Cost Effectiveness of LEC, $/ton
C-01	1,350	$942,500	$100,000	$164,876	8,656	116	$1,422
C-02	1,350	$942,500	$100,000	$164,876	4,971	67	$2,476
C-03	1,350	$942,500	$100,000	$164,876	5,321	71	$2,314
C-04	1,350	$942,500	$100,000	$164,876	7,770	104	$1,584
C-05	1,350	$942,500	$100,000	$164,876	5,431	73	$2,267

[289] *Id.* at Appendix B.
[290] *Id.*
[291] See 2019 Four-Factor submittals for Roswell Compressor Station and Jal No. 3 which both assume 25-year life of controls for LEC.

Unit	Size [hp]	Capital Cost of LEC to Reduce NOx from a Permitted Rate of 11 g/hp-hr	Annual O&M Costs	Total Annualized Costs of LEC to Reduce NOx to 2 g/hp-hr (81% NOx Reduction)	Annual Operating Hours, hr/yr	NOx Removed, tpy	Cost Effectiveness of LEC, $/ton
C-06	1,350	$942,500	$100,000	$164,876	1,910	26	$6,445
C-07	1,195	$945,000	$100,000	$165,048	5,622	66	$2,504
C-08	1,195	$945,000	$100,000	$165,048	2,948	35	$4,776
C-09	1,800	$615,500	$100,000	$142,367	5,989	106	$1,346

The cost effectiveness of LEC control could be significantly lower than what is shown above for engines that operate more frequently than in 2016. Targa stated, in its Addendum, that "[w]ith regards to the engine usage, Targa attempts to use its engines uniformly but this does not mean equally on a calendar year basis."[292] An analysis that assumes each engine operates at the average annual operation across all engines in 2016, which is roughly 5,400 hours per year, would result in cost effectiveness estimates as low as $2,279/ton for unit C-06 and $2,606/ton for unit C-08.

2. Use of SCR.

Targa did not evaluate SCR for these units, primarily because it claimed that, "most 2SLB engines have a poor air-to-fuel ratio that will not support the SCR control."[293] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for these engines, particularly because Targa does not consider LEC to be economical.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[294]

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[292] February 2020 Regional Haze Four-Factor Analysis Addendum for Targa Midstream Services, LLC – Eunice Gas Plant, Monument Gas Plant, Saunders Gas Plant at pdf page 13.
[293] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant at 2-8.
[294] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[295] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[296] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

B. Units G-01, G,02, and G-03: Natural Gas-Fired 4-Stroke Rich-Burn RICE

Units G-01 through C-03 are Ingersoll-Rand PKVG-8 4-stroke rich-burn generator engines that were constructed in 1953, each with a capacity of 780 hp.[297] These units each have an hourly NOx limit of 34.2 lb/hr and an annual NOx limit of 149.8 tpy.[298]

1. Evaluation of Baseline NOx Emissions

Targa's four-factor submittal includes baseline unit-specific NOx emission rates in hours per year and tons per year, based on 2016 emission inventory calculations.[299] Operating hours can be calculated based on these data. These baseline NOx emission rates and the allowable NOx emission rates from the source's Title V permit are shown in the table below.[300]

Table 18. Targa Saunders Gas Plant 4SRB RICE Unit NOx Emission Rates

Unit	Size [hp]	NOx Permit Limit [lb/hr]	NOx Baseline Emissions [lb/hr]
G-01	780	34.2	19.81
G-02			21.63
G-03			17.4

As shown, the baseline emission rates for all three units are significantly lower than the units' allowable hourly NOx emission rates so, either the baseline emissions for these units is not reflective of operation at maximum capacity or the allowable NOx emission rates for these units

[295] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[296] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[297] Title V Operating Permit P111-R2M2 for Saunders Gas Plant at A7.
[298] *Id.* at A9.
[299] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant Appendix B.
[300] *Id*.

have been set unreasonably high. NMED and Targa should review performance tests for these units to ensure that the actual emission rates can be considered to truly reflect baseline emissions over the lifetime of the controls being evaluated.

According to the September 2018 Title V renewal application for the Saunders Gas Plant, NOx emissions for units G-01 through G-03 were," calculated using stack test data from 2/22/1994 with a 20% safety factor."[301] The permitted rates for these units—that are based on stack test data—are significantly higher than the baseline NOx emission rates that the company's four-factor cost effectiveness analysis is based upon, even considering the 20% "safety factor", meaning NOx reductions estimates for the various control options considered for these units may be underestimated. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on a more comprehensive estimate of emissions expected in 2028.

2. Use of Non-Selective Catalytic Reduction

Targa determined that non-selective catalytic reduction (NSCR) is a technically feasible option for the 4SRB RICE units at the Saunders Gas Plant and the cost analysis provided in its four-factor analysis indicates this control could be very cost effective for these units.[302] Despite this, Targa concludes these retrofits would be uneconomical.[303]

The cost analysis in Targa's four-factor submittal doesn't support this claim for these engines, and the cost effectiveness of controls may be even more favorable than what is presented by Targa.

In its November 2019 submittal, Targa presents cost effectiveness of controls for G-01, G-02, and G-03 of $259/ton, $231/ton, and $287/ton, respectively.[304] The capital cost estimates are based on "information received from engine control vendors or knowledge on the particular equipment."[305] Targa's February 2020 Addendum did not include any revisions to these cost estimates.

The annual hours of operation for these engines is around 7,000 hours per year, based on the pound per hour and ton per year emission rates provided in Targa's submittal:

[301] *See* September 2018 Title V Permit Application for Saunders Gas Plant at pdf page 37.
[302] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant at 2-6 and 3-2.
[303] *Id.* at 7-1.
[304] *Id.* at 3-2.
[305] *Id.* at B-1.

Table 19. Targa Saunders Gas Plant 4SRB RICE Units Annual Operation Based on 2016 EI Calculations

Unit	Size [hp]	NOx Baseline Emissions [lb/hr]	NOx Baseline Emissions [tpy]	Hours of Operation [hr/yr]
C-01	780	19.81	69.47	7,014
C-02	780	21.63	77.28	7,146
C-03	780	17.14	63.52	7,412

NMED should request operation data for additional years for these units in order to be able to better assess the cost effectiveness of controls for operating schedules that reflect greater usage of these engines, as allowed by current permit limits, e.g., if increased usage would be more representative of typical operation in 2028.

In Targa's submittal, its cost effectiveness analysis assumes controlled NOx emission rates of 0.986 g/hp-hr, based on "a similar unit at the site which is controlled by NSCR."[306] The corresponding NOx emissions reductions in Targa's four-factor analysis for units G-01, G-02, and G-03 are 91.9%, 92.6%, and 90.7% respectively.[307] Note, greater emissions reductions would result from control of these units if they operate at levels closer to permitted levels (which are, again, based on test data), meaning NSCR would be even more cost effective than what is shown in Targa's four-factor analysis. Targa states that, "NSCR controls are typically 90% or greater."[308] For uncontrolled permitted emission rates of 34.2 g/hp-hr, controlled rates of 0.986 g/hp-hr would achieve 97% reduction in NOx emissions. According to EPA's Alternative Control Techniques document for RICE, NSCR vendors quote NOx emission reduction efficiencies of 90 to 98%, resulting in an expected range of controlled NOx emissions from 0.3-1.6 g/hp-hr.[309]

As a result of assuming what could be low NOx emission rates for baseline uncontrolled emissions from these 4SRB RICE, i.e., emission rates based on performance test data that show lower rates than the permitted limits for these units (that, according to Targa's Title V permit application, are also based on stack data), Targa then also potentially further underestimates the magnitude of potential NOx reductions for these units in its cost effectiveness analysis. Therefore, the potential emissions reductions achieved by retrofitting these units could be much greater than what the four-factor analysis shows due to potential underestimated baseline emissions, hours of operation, and emissions reductions.

With respect to the life assumed for LEC control, Targa assumed a 10-year period.[310] Targa does not provide any justification for this assumption for the life of controls. In the NPCA

[306] *Id*. at 3-1.
[307] *Id.* Appendix B.
[308] *Id.*at 2-6.
[309] EPA 1993 Alternative Control Techniques Document for RICE at 2-10 to 2-11.
[310] November 2019 Regional Haze Four-Factor Analysis for Targa – Saunders Gas Plant Appendix B.

March 2020 Oil and Gas Four-Factor Report, we assumed a 15-year life of controls in determining the cost effectiveness of NSCR control for 4SRB RICE.[311]

Also, Targa uses an interest rate of 8.25% which is high and therefore underestimates annualized costs of control for these engines. As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.

Revising Targa's cost effectiveness analyses to address some of these issues, including assuming 1) a 4.7% interest rate (instead of 8.25%), 2) a 15-year life of NSCR (instead of an assumed 10-year life), and 3) emissions reductions of 97% based on potential operation at permitted levels (largely based on stack test data), improves cost effectiveness of these controls even further, as shown in the table below.

Table 20. Cost Effectiveness of NSCR at Uncontrolled Saunders Gas Plant Units G-01, G-02, and G-03 to Reduce NO_x Levels to 0.986 g/hp-hr, Assuming 97% Reductions in NOx Emissions, a 4.7% Interest Rate, and a 15-Year Life of Controls

Unit	Size [hp]	Capital Cost of NSCR to Reduce NOx from a Permitted Rate [2019$]	Annual O&M Costs [2019$]	Total Annualized Costs of LEC to Reduce NOx to 0.986 g/hp-hr (97% NOx Reduction) [2019$]	Annual Operating Hours, hr/yr	NOx Removed, tpy	Cost Effectiveness of NSCR [2019$], $/ton
C-01	780	$8,206	$15,308	$16,083	7,014	116	$138/ton
C-02	780	$8,206	$15,308	$16,083	7,146	119	$136/ton
C-03	780	$8,206	$15,308	$16,083	7,412	123	$131/ton

Based on this analysis, it is *extremely* cost effectiveness to retrofit these 4SRB RICE with NSCR and would result in the removal of over 350 tons per year of NOx.

VII. DCP Artesia Gas Plant

The Artesia Gas Plant is a natural gas processing plant that removes condensate, H_2S and CO_2 in an amine unit, and separates natural gas liquids.[312] The plant is located about 15 miles east-southeast of Artesia, New Mexico. It is owned/operated by DCP Midstream. The plant consists of numerous natural gas-fired four-stroke rich-burn RICE units, natural gas-fired four-stroke lean-burn RICE, boilers, amine contactor, flares, and other emissions sources.[313] Of all of those sources of emissions, NMED apparently only requested a four-factor analysis for the flares at

[311] *See* NPCA March 2020 Oil and Gas Four-Factor Report at 20.
[312] 6/27/2017 Title V Permit No. P095-R3 for Artesia Gas Plant at A3.
[313] *Id.* at A6 to A8.

the plant. Notably, all of the four-stroke rich-burn RICE are equipped with nonselective catalytic reduction for NOx control. In Section XXIII further below, we provide comments on the four-factor analysis for the flares associated with the amine unit.

VIII. Harvest Four Corners – Kutz Canyon Gas Plant

Kutz Canyon Gas Plant is a natural gas processing plant that removes ethane and heavier hydrocarbons from natural gas. It is operated by Harvest Four Corners, LLC. The facility is located in San Juan County, about 3.1 miles south of Bloomfield, New Mexico. According to NMED's Statement of Basis for a New Source Review (NSR) permit for the facility, "The Kutz I Plant removes heavier hydrocarbons using a refrigerated lean oil absorption process and was built in 1936. The Kutz II Plant removes heavier hydrocarbons using a cryogenic process and was added to the facility much later, in 1975. The facility operates 8760 hours per year."[314] The Title V operating permit for the facility indicates that the plant includes several natural gas-fired turbines, boilers, several natural gas-fired RICE, heaters, boilers, and flares.[315] In Harvest Four Corner's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Solar Centaur 40 combustion turbines (Units 1-6 and Units 19 and 20)
- Clark HRA-8 two-stroke lean burn RICE (Units 16, 17, and 18)[316]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tons per year (tpy), which is the criteria established by NMED to identify sources subject to four-factor analyses.[317] The following provides a review of the company's four-factor analyses.

A. Interest Rate Used in Cost Analyses.

Harvest Four Corners used a 5.5% interest rate in the cost analyses for all of the controls evaluated in its 4-factor analyses.[318] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. This is the same interest rate that EPA has used in its cost spreadsheet for SCR, but EPA also states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[319] The current bank prime rate is 3.25%.[320] The highest the bank

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[314] NMED Statement of Basis, NSR Permit No. 0301-M11 and P097-R3-R3M1, 8/20/2019, at 1.
[315] Title V Operating Permit P097-R3 for Kutz Canyon Processing Plant at A6 to A8.
[316] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 1-2.
[317] *Id.*
[318] *Id.* at Section 8.0 Supporting Documentation.
[319] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[320] https://www.federalreserve.gov/releases/h15/.

prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[321] In a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[322] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. For these reasons, in the cost effectiveness calculations provided herein, a 4.7% interest rate is used rather than a 5.5% interest rate.

B. Solar Centaur Natural Gas-Fired Combustion Turbines (Units 1-8 and 19 and 20) at the Kutz Canyon Gas Plant.

The combustion turbines evaluated at the Kutz Canyon Gas Plant are Solar combustion turbines, model Centaur 40 of 3830 hp capacity (Units 1-6) and of 3016 hp capacity (Units 19 and 20).[323] These units were manufactured between 1975 and 1981.[324] Under the terms of the permit, the units are subject to the following hourly and annual emission limits of NOx.

Table 21. Limits from Kutz Canyon Gas Plant Title V Permit for the Units 1-8 and 19-20 Combustion Turbines[325]

Combustion Turbine Unit ID	NOx limit, lb/hr	NOx limit, tpy
1	15.5	67.9
2	15.5	67.9
3	15.5	67.9
4	15.5	67.9
5	15.5	67.9
6	15.5	67.9
19	15.5	67.9
20	15.5	67.9

Units 19 and 20 are also subject to NOx limits of 161.91 ppmv at 15% O_2, pursuant to 40 C.F.R. Part 60, Subpart GG.[326]

Harvest Four Corners evaluated one control option for these combustion turbines: Solar's SoLoNOx combustion system. The company did not evaluate SCR, claiming that it would not operate effectively at the units and that there was not space available for SCR or power

[321] https://fred.stlouisfed.org/series/DPRIME.
[322] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.
[323] Title V Operating Permit P097-R3 for Kutz Canyon Processing Plant at A6.
[324] *Id.*
[325] *Id.* at A9-A10.
[326] *Id.* at A26.

capabilities for such SCR systems.[327] For reasons previously discussed above and in the NPCA Oil and Gas Four-Factor Report, SCR should have been considered as a technically feasible control for these natural gas-fired combustion turbines.

1. Baseline Emissions for the Units 1 – 6 and 19-20 Combustion Turbines.

Harvest Four Corners states that its cost effectiveness analyses for SoLoNOx were based on the 2016 emission inventory submittal.[328] In its cost data sheets in Section 8.0 of its four-factor analysis, the company provided the 2016 emission inventory calculations for the combustion turbines evaluated, but the company did not specify the actual 2016 operating hours for each unit.[329] This is inconsistent with most other four-factor analyses submitted to NMED. Submittal of operating hours is very important for understanding the operating capacity factor of the units, and NMED must require that more specific operational data be made public for the units as part of the four-factor analyses of controls. The company also provided the NOx ppm rate, but it was "converted from 2016 [emission inventory] calculations and data."[330]

Specifically, the company's cost data sheets indicate that the NOx ppm rate for each unit is 67.61 ppm.[331] That NOx concentration was then compared to the NOx emission rate guarantee from SoLoNOx of 25 ppm to determine the percent NOx reduction which was then multiplied by 2016 tpy emissions to determine the NOx removed for the cost effectiveness analysis of SoLoNOx. NMED must require Harvest Four Corners to provide more specific data on how the NOx ppm rate was calculated. Further, each of the units is subject to emission testing requirements of the Title V permit.[332] Such actual emissions tests should be evaluated as well (including the circumstances of the test data) to ensure that the baseline emissions inventory and emission rates are reflective of current actual emissions and emissions expected from the units in 2028. A review of Title V permit application data for the Kutz Canyon Gas Plant on the NMED's Emissions Analysis Tool did not find any other emissions testing data available for these units.

Units 19 and 20 are also subject to NOx limits of 161.91 ppmv at 15% O_2, pursuant to 40 C.F.R. Part 60, Subpart GG as discussed above. This is 2.4 times higher than the 67.61 ppm base NOx rate relied upon by Harvest Four Corners to determine the tons per year of NOx removed due to SoLoNOx. In addition, Units 19 and 20 are different Solar Centaur models than Units 1-6 (T4001 versus T4002). Further, Units 19 and 20 have a lower horsepower rating than Units 1-6. Yet, all eight units were assumed to have the same uncontrolled NOx baseline emission rate. The discrepancies between these two NOx rates need to be addressed by NMED to ensure that

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[327] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 2-4 to 2-5.
[328] *Id.* at 2-10.
[329] *Id.* at Section 8.0, pdf pages 30-37.
[330] *Id.*
[331] *Id.*
[332] Title V Operating Permit P097-R3 for Kutz Canyon Processing Plant at A25.

baseline emissions are based on a valid analysis of actual emissions that are projected to occur in 2028.

2. Evaluation of SoLoNOx for the Combustion Turbines at Units 1-6 and 19-20.

Harvest Four Corners indicates that SoLoNOx can achieve a NOx rate of 25 ppm, which it claims is a reduction of 63% "based on the currently permitted hourly emission rate and turbine stack parameters."[333] This makes clear that Harvest Four Corners is using the 67.71 ppm NOx rate identified in its SoLoNOx cost data sheets along with the 25 ppm NOx rate expected from SoLoNOx to calculate the tons per year NOx reductions expected with SoLoNOx.[334] This statement implies that the NOx baseline emission rate of 67.71 ppm that Harvest Four Corners cites in its SoLoNOx cost data sheets is based on the allowable pound per hour emission limits applicable to each unit. However, in the cost data sheets of Section 8.0 of the Kutz Canyon Gas Plant four-factor analysis, it is stated that the 67.71 ppmv was calculated from the 2016 emission inventory data. Given that this baseline rate forms the basis of the company's claimed NOx removal efficiency with SoLoNOx, NMED must disclose the basis for this base concentration.

In terms of the life of SoLoNOx controls in the cost effectiveness analyses, Harvest Four Corners' analysis assumed a 20-year life. For the reasons described above on the evaluation of dry low NOx combustors at the gas turbines at the Chaco Gas Plant, a 25-year life is a more appropriate assumption for the cost effectiveness analysis.[335] In the table below, Harvest Four Corners' cost effectiveness analyses of SoLoNOx were revised to take into account a longer lifetime of controls and a lower 4.7% interest rate.

[333] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 2-3.
[334] A 25 ppm NOx rate reflects 63% NOx reduction from a 67.71 ppm NOx rate.
[335] *See also* NPCA March 2020 Oil and Gas Four-Factor Report at 69-70.

Table 22. Revised Cost Effectiveness of SoLoNOx at Units 1-6 and 19-20 of the Kutz Canyon Gas Plant, to Reflect a 4.7% Interest Rate and a 25 Year Life

Unit	Harvest Four Corners' Total Annual Costs of SoLoNOx (at 5.5% Interest and 20-Year Life)	Harvest Four Corners' Cost Effectiveness at 5.5% Interest and 20 Year Life	Revised Total Annual Costs of SoLoNOx	Revised Cost Effectiveness at 4.7% Interest and 25 Year Life
1	$61,603	$2,246/ton	$54,666	$1,993/ton
2	$61,603	$2,412/ton	$54,666	$2,141/ton
3	$61,603	$1,983/ton	$54,666	$1,760/ton
4	$78,339	$23,111/ton	$68,433	$20,183/ton
5	$78,339	$2,145/ton	$68,433	$1,873/ton
6	$78,339	$1,910/ton	$68,433	$1,668/ton
19	$61,603	$4,779/ton	$54,666	$4,242/ton
20	$61,603	$2,043/ton	$54,666	$1,813/ton

It must be noted that, for some unexplained reason, the capital cost to install SoLoNOx at Units 4, 5, and 6 was $200,000 higher than the capital cost to install SoLoNOx at the other combustion turbine units. Yet, Units 4, 5, and 6 are the same turbine model as Units 1, 2, and 3 (Model T4002).[336] NMED should evaluate the reason for the higher capital cost of SoLoNOx at Units 4, 5, and 6.

For Unit 4, the unit had very low NOx emissions in 2016 of 5.38 tpy, and thus the cost effectiveness of SoLoNOx was very high at this unit. NMED must ensure that these low NOx emissions at Unit 4 are not anomalous and that the company's baseline emissions for the unit are reflective of expected operations in 2028. With the exception of Unit 4, the cost effectiveness of SoLoNOx at these combustion turbines are in the range of $1760/ton to $4,242/ton to achieve 63% NOx reduction, which is very cost effective.

3. SCR at Units 1-6 and 19-20 at Kutz Canyon Gas Plant

As discussed above, Harvest Four Corners did not evaluate SCR for any of the combustion turbine units, claiming that the exhaust temperatures of the turbines is 1,271 degrees Fahrenheit which the company claims would negatively impact SCR operation, and also that there are site-specific space limitations for installation of SCR. With respect to space limitations, as discussed in Section I.B.3. above, most SCR retrofits have space limitations, because the facility was not likely designed to have space to accommodate SCR. There have been numerous SCR retrofits installations at various industrial facilities that have had to overcome space constraints. For example, for many large coal-fired power plants, SCR reactors

[336] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at Section 8.0.

have been elevated above the air preheaters. Indeed, a report about SCR retrofits at GE LM2500 turbines at Chevron's Eastridge Cogeneration plant in California showed that some significant changes to the facility had to be made to accommodate SCR, including cutting the duct between economizers and moving the stack and one economizer onto new foundations to make way for the SCR reactor.[337] Thus, before NMED accepts a very brief claim of retrofit difficulty of SCR at any emissions unit being evaluated for reasonable progress controls, it is imperative that NMED ask Harvest Four Corners for a site plan and photos that shows whatever space constraints are being claimed, and that NMED ask the company to consult with SCR vendors for options for SCR installation at the gas turbines.

Depending on the proximity of the gas turbines, it is possible that one SCR reactor could be used by more than one combustion turbine. This would reduce costs and potentially be easier to install at the site. NMED should require all possibilities for SCR installation to be evaluated and documented by Enterprise. The state must not simply discount this highly effective NOx control based on a claim of some retrofit difficulty.

Regarding the company's stated exhaust temperature of 1,271 degrees Fahrenheit, NMED should determine if this is the sustained temperature of the gas turbines or the maximum temperature of the exhaust expected from the Units 1-6 and Unit 19-20 gas turbines. There are options for dealing with high exhaust temperatures of simple cycle turbines to enable the use of SCR. The Buckingham Compressor Station which is proposed to be constructed in Virginia would be equipped with Solar turbines with SoLoNOx, SCR, and cooling air skids.[338] Essentially, this provides for the injection of tempering air at the turbine discharge (upstream of the SCR) to cool the exhaust temperature to the optimal temperature of the SCR catalyst.[339]

Further, these high exhaust temperatures are another reason why NMED should investigate routing more than one combustion turbine exhaust to a common SCR. The routing of the turbine exhausts from multiple turbines to one SCR reactor will allow for some cooling of the exhaust before it enters the SCR. Salt River Project (SRP) is planning to route the flue gas from one boiler at the Coronado Generating Station in Arizona to an existing SCR reactor that had previously been constructed at Coronado Unit 2.[340] It will be a shared SCR system, although it must be noted that the Coronado Unit 1 SCR was designed as a split (two towers within one

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[337] *See* Seebold, James et al., Gas Turbine NOx Reduction Retrofit, , available at https://www.onepetro.org/conference-paper/SPE-66501-MS.

[338] *See* May 25, 2018 Permit Application for Altlantic Coast Pipeline LLC, Buckingham Compressor Station, at pdf page 129 (Design Summary), which is available for download at https://www.deq.virginia.gov/Programs/Air/BuckinghamCompressorStationAirPermit/BuckinghamCompressorStationArchivedDocuments.aspx.

[339] *See,* e.g., Buzanowski, Mark A. and Sean P. McMenamin, Peerless Mfg. Co., Automated Exhaust Temperature Control for Simple Cycle Power Plants, available at https://www.powermag.com/automated-exhaust-temperature-control-for-simple-cycle-power-plants/. *See also* Mitsubishi Hitachi Power Systems (MHPS) webpage on SCR systems for simple cycle turbines at https://amer.mhps.com/scr-for-simple-cycle-gas-turbines.html.

[340] *See* January 6, 2020, SRP Newsroom, SRP Selects Operation Plan for Coronado Generating Station, Units 1 and 2 to Run on Existing Selective Catalytic Reduction until 2032, available at https://media.srpnet.com/srp-selects-operation-plan-for-coronado-generating-station/.

reactor) SCR system. So, according to SRP, each unit will have its own SCR within one reactor. Such an approach seems like it could be a viable, more cost effective control option for co-located combustion turbines at compressor stations.

One further reason that Harvest Four Corners identified for SCR not being feasible was due to the electricity needs of the SCR. Harvest Four Corners states that it "does not anticipate that the current electricity availability at Kutz will be sufficient to support the substantial energy burden associated with SCR control" and that "[i]nstallation of this control will require the facility to expand its current power generation."[341] The site has two onsite combustion turbine generators in Units 19 and 20. The Title V Permit states that each of these two generators cannot exceed 2400 kilowatts, and also states that only one unit can operate at any given time.[342] This condition was apparently imposed pursuant to a NSR Permit 0301M9. If this condition was imposed to allow a project to net out of PSD review, then the operational limits cannot be relaxed without the units obtaining a permit as though construction had not yet commenced.[343] But if the units install BACT level controls (SoLoNOx plus SCR), then the burden of obtaining a PSD permit for the units in order to allow both units to produce the needed electricity to operate SCRs may not be substantial. According to EPA's cost spreadsheet for the similar size units to Units 1-6 and 19-20 of the Kutz Canyon Gas Plant, the electricity usage for SCR at the turbines operating at maximum capacity would be approximately 20 kW per hour. Assuming very conservatively that the power for a cooling air skid might double these power needs to 40 kW per hour, the total electricity need for 8 SCR systems (if all combustion turbines being evaluated in this four-factor analysis were equipped with SCR) would very conservatively be 320 kW. If 2400 kW is the maximum capacity of each of Units 19 and 20, this power need reflects 13% of one of the Units 19 or 20 generating units. Given that both generating units are currently not allowed to operate simultaneously under the terms of the permit, it appears that the plant currently has the generating capacity to address worst case electricity needs of SCR systems on each of the eight combustion turbines if the permit was revised to allow for simultaneous operation of both Units 19 and 20.[344]

For all of the reasons discussed above, SCR should not have been excluded from review as a possible NOx control option for Units 1-6 and Units 19-20 at the Kutz Canyon Gas Plant, both by itself and in combination with SoLoNOx.

As discussed above, an SCR installation by itself should be able to reduce emissions to at least 15 ppmv at 15% O_2.[345] That NOx rate reflects a 40% reduction in NOx emissions compared to

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[341] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 2-5.
[342] Title V Operating Permit P097-R3 for Kutz Canyon Processing Plant at A26, Condition A205.C.
[343] *See* 40 C.F.R. 52.21(r)(4).
[344] As previously stated, the ability to allow both Units 19 and 20 to operate simultaneously
Depends on the reasons that these operational limitations were imposed at Units 19 and 20. If imposed as "synthetic minor" limits or to allow other projects at the facility to net out review, relaxations in those operational restrictions can be allowed if all regulatory requirements including PSD permitting requirements are addressed.
[345] *See* March 2020 NPCA Oil and Gas Four-Factor Report at 75.

the 25 ppm expected NOx rate with SoLoNOx at Units 1-6 and Units 19-20. Further, a 15 ppmv NOx rate reflects a 78% reduction in NOx from Harvest Four Corners' claimed baseline NOx rate for each unit of 67.61 ppm. Based on the fact that the combustion turbines at the Eunice Gas Plant (Units 17A, 18B, 19A, 25A, and 26A) evaluated for SCR by DCP Midstream are of similar size as the Kutz Canyon Units 1-6 and 19-20 combustion turbines, one would expect SCR to have a similar cost effectiveness. As shown in Table 9 above, the cost effectiveness SCR at the DCP Eunice Gas Plant turbines ranged from $2,600/ton to $3,800/ton (assuming a 4.7% interest rate and 25-year life). Thus, one would expect the similar (or same) model turbine and similar size units at Kutz Canyon to have a similar cost effectiveness of SCR to achieve 15 ppmv at 15% O_2, with the exception of units that are not operated at similar levels as the Eunice turbines such as Kutz Canyon Unit 4.

Moreover, SCR combined with SoLoNOx, which is commonly required to meet BACT for gas turbines, could reduce NOx by 97% or more. As discussed in Section I.C.2 of this report, this combination of NOx controls has been permitted for the Buckingham Compressor Station to achieve a NOx emission rates of 3.75 ppmv @ 15% oxygen.[346] However, emission rates with SoLoNOx and SCR at gas-fired combustion turbines could be even lower, as BACT or LAER for such turbines operated for power generation are generally set at 2 to 2.5 ppmv at 15% oxygen.[347] NMED should require Harvest Four Corners to evaluate the cost effectiveness of the combination of SoLoNOx and SCR to achieve the greatest level of NOx reduction.

C. Clark HRA-8 Two-Stroke Lean-Burn RICE (Units 16-18) of Kutz Canyon Gas Plant

Units 16, 17, and 18 are Clark HRA-8 two-stroke lean-burn refrigerant compressor engines that were constructed in prior to 1973, each with a nameplate capacity of 830 hp and a site-rated capacity of 723 hp.[348] These units each have an hourly NOx limit of 37.1 lb/hr and an annual NOx limit of 162.0 tpy.[349]

1. Evaluation of Baseline NOx Emissions

Harvest Four Corners' four-factor submittal includes baseline NOx emissions (in tpy) based on 2016 emission inventory calculations; no information is provided on operating hours for these engines. NMED should request more information on the units' current hours of operation and

[346] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.
[347] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand and Curve Reset, at 9.
[348] Title V Operating Permit P1097-R3 for Kutz Canyon Processing Plant at A6-A7.
[349] *Id.* at A9.

actual NOx emissions. The baseline emission rates for these units, based on 2016 emission inventory calculations, and the allowable NOx emission rates are shown in the table below.[350]

Table 23 Harvest Four Corners Kutz Canyon Processing Plant 2SLB RICE Unit NOx Emission Rates

Unit	Size [hp]	NOx Permit Limit [tpy]	NOx Baseline Emissions [tpy]
16	723	162.0	151.37
17	723	162.0	89.63
18	723	162.0	87.5

Without information on operating hours it's not possible to know if baseline NOx emissions from units 17 and 18 are lower than permitted rates because these units operated fewer hours in 2016 or if their hourly emission rates were lower.

According to the May 2019 permit application for the Kutz Canyon Processing Plant, NOx emissions for these units were determined, "using stack test and manufacturer's data."[351] The permitted rates for units 17 and 18—that are based on stack test and manufacturer data—are significantly higher than the NOx emission rates that the company's four-factor cost effectiveness analysis is based upon, meaning NOx reductions estimates for the various control options considered may be underestimated if 2016 operation is not reflective of operation in current and future years. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on a more comprehensive estimate of operating hours and emission rates (e.g., in g/hp-hr or hr/yr) expected in 2028.

2. Use of Low Emission Combustion Technology

Harvest Four Corners describes the LEC control technologies for these 2SLB Clark engines as "Clean Burn Technology (CBT)."[352] According to EPA, "[t]he term "clean-burn" technology is a registered trademark of Cooper Energy Systems and refers to engines designed to reduce NOx by operating at high air-to-fuel ratios."[353] It's not entirely clear what specific technologies are being proposed for the Clark engines at the Kutz Canyon Gas Processing Plant. Harvest Four Corners' submittal discusses, generally, the use of high energy ignition system, turbocharger, and AFRC technologies.[354] EPA described LEC retrofit kits designed to achieve extremely lean

[350] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant Appendix B.
[351] *See* May 2019 Permit Revision Application to NSR Permit 0301-M10 for Kutz Canyon Processing Plant, Section 6 Page 2.
[352] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 2-6.
[353] EPA AP-42 Chapter 3, Section 3.2 (July 2000) at 3.2-2.
[354] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 2-7.

air-to-fuel ratios – in order to minimize NOx emissions – as encompassing the following specific retrofit technologies:

- Redesign of cylinder head and pistons to improve mixing (on smaller engines)
- Precombustion chamber (on larger engines)
- Turbocharger
- High energy ignition system
- Aftercooler
- Air-to-fuel ration controller (AFRC)[355]

In order to effectively evaluate a company's assessment of LEC a more precise description of LEC technologies, and associated achievable emission rates is needed. Harvest Four Corners states that Clean Burn Technology is estimated to achieve an 80 to 93% reduction in NOx emissions, depending on engine and loading.[356] Harvest Four Corners assumes an 80% NOx reduction in its four-factor analysis for these engines.

The allowable NOx emission rate for these 723 hp engines, at 37.1 lb/hr, is equivalent to 23.3 g/hp-hr. An 80% reduction in NOx emissions would achieve a NOx level of over 4 g/hp-hr. NPCA's March 2020 Oil and Gas Four-Factor Report stated that a wide range of emission rates are achievable with LEC technology, with NOx emissions generally no higher than 2 g/hp-hr and often significantly lower (e.g., as low as 0.5 g/hp-hr).[357]

For reference, the following sources of information regarding NOx emission rates specific to Clark engines – both uncontrolled and with LEC technology – are provided here:

- EPA's 2000 RICE Update includes NOx emissions test data for specific engines, including Clark Model TLA-6, 2-stroke, lean-burn, 2,000 hp RICE retrofitted with LEC. According to EPA, six engines retrofitted by a third-party vendor had NOx emission rates ranging from 0.8–1.4 g/bhp-hr, with a mean of 1.0 g/bhp-hr.[358]

- An evaluation by a technical group for the Pipeline Research Council International looked at three of the most representative make / models of 2-stroke lean burn compressor engines: (1) 2,250 hp Cooper GMVH-10; (2) 2,000 hp Clark TLA-6; and (3) 2,500 hp Cooper GMW-10. According to a technical report by the Ozone Transport Commission (OTC) describing this evaluation, "[t]he evaluation concluded that there

[355] EPA, Final Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Docket ID EPA-HQ-OAR-2015-0500-0508, Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance, August 2016, Appendix A at 5-3, *available at:* https://www.regulations.gov/document?D=EPA-HQ-OAR-2015-0500-0508 [hereinafter referred to as "2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls"].
[356] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 2-7, citing EPA's 1993 Alternative Control Techniques document for RICE.
[357] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 28.
[358] EPA 2000 RICE Update at 4-8.

> were no technology gaps and that each of the three makes/models evaluated were capable of attaining a NOx emissions limitation of 0.5 g/bhp-hr using a combination of improvements and retrofits related to air supply, fuel supply, ignition, electronic controls, and engine monitoring."[359]

For the units at the Kutz Canyon Processing Plant, a controlled NOx emission rate of 2 g/hp-hr from the uncontrolled allowable NOx emission rate (that is based on stack test and manufacturer data) represents a 91% emissions reduction, which is in the range presented in Harvest Four Corners' four-factor submittal of 80 to 93%.

Harvest Four Corners presents cost effectiveness of LEC controls for these units that range from $1,021–$1,767 per ton.[360] The capital cost estimates of $1 million and annual operating and maintenance cost estimates of $40,000 per year are provided by Harvest Four Corners.[361] These capital cost estimates are a little higher, at $186/hp, compared to other capital cost estimates for LEC controls at other similar engines.[362]

Harvest Four Corners assumes NOx emissions reductions of 80% despite stating that the Clean Burn technologies it would employ are capable of reducing NOx emissions up to 93%.[363] And achieving NOx emission rates of 2 g/hp-hr—as shown by other companies in their four-factor analyses for similar engines at similar costs—would correspond to 91% NOx reductions.[364] These greater emissions reductions would result from control of units that are operating at levels closer to permitted levels (which are, again, based on stack test and manufacturer data) and would mean that the LEC controls would be even more cost effective than what is shown in Harvest Four Corners' original four-factor analysis.

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[359] Ozone Transport Commission, Technical Information, Oil and Gas Sector, Significant Stationary Sources of NOx Emissions, Final, October 17, 2012, p. 24, *available at*: https://otcair.org/upload/Documents/Meeting%20Materials/Final%20Oil%20%20Gas%20Sector%20TSD%2010-17-12.pdf [hereinafter referred to as "2012 OTC Report"].

[360] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 3-2.

[361] *Id.* Appendix B. Note, these capital cost estimates are in line with other company analyses for similar engines, e.g., Targa's original Four-Factor analysis for Clark HBA-8 engines used capital cost estimates of $950,000. Also, EPA's 2000 RICE Update (p. 5-2) included capital cost estimates for third-party retrofit of a Clark Model HSRA, 2SLB 1,000 hp 8-cylindar engine at a pipeline station of $710,000

[362] *See, e.g.*, November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant cost data for Clark engines at just under $140/hp. *See also* November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant cost data for Clark engines, also under $140/hp.

[363] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant at 2-7.

[364] *See* November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Eunice Gas Plant at 3-3 and November 2019 Regional Haze Four-Factor Analysis for Targa Midstream Services, LLC – Monument Gas Plant at 3-2, assuming controlled NOx rates of 2 g/hp-hr for Clark engines.

With respect to the life assumed for LEC control, Harvest Four Corners assumed a 20-year period.[365] This assumption appears to be based on EPA's guidance default for SCR.[366] It's possible that LEC controls can last 25 years, as stated in other cost effectiveness analyses submitted to NMED for LEC controls.[367]

Also, Harvest Four Corners uses an interest rate of 5.5% which is likely high and therefore underestimates annualized costs of control for these engines.[368] As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. Revising Harvest Four Corners cost effectiveness analyses to address some of these issues, including assuming 1) a 4.7% interest rate (instead of 5.5%), 2) a 25-year life of LEC (instead of an assumed 20-year life), and 3) emissions reductions of 91% from baseline emissions, improves cost effectiveness of these controls even further, as shown in the table below.

Table 24. Cost Effectiveness of LEC at Uncontrolled Kutz Canyon Gas Processing Plant Units 16, 17, and 18 to Reduce NO_x Levels to 2 g/hp-hr, Assuming 91% Reductions in NOx Emissions, a 4.7% Interest Rate, and a 25-Year Life of Controls, 2019 $

Unit	Size [hp]	Capital Cost of LEC to Reduce NOx from Baseline Emissions	Annual O&M Costs [2019$]	Total Annualized Costs of LEC to Reduce NOx to 2 g/hp-hr (91% NOx Reduction)	Annual Baseline Emissions, tpy	NOx Removed, tpy	Cost Effectiveness of LEC, $/ton
16	723	$1,000,000	$40,000	$134,399	151	138	$790/ton
17	723	$1,000,000	$40,000	$134,399	90	82	$1,334/ton
18	723	$1,000,000	$40,000	$134,399	88	80	$1,367/ton

Harvest Four Corners determined that LEC technology is a technically feasible option for the 2SLB RICE units at the Kutz Canyon Gas Processing Plant and the cost analysis provided in its four-factor analysis, and revised here, confirms this control would be very cost effective. Harvest Four Corners expresses concern that the addition of these controls may be "operationally detrimental" due to the need for a third-party installation. However, no additional specific examples of operational impacts are identified or explained that would necessarily preclude retrofit of these engines. Just because there may be operational issues to

[365] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant Appendix B.
[366] *Id.*
[367] See 2019 Four-Factor submittals for Roswell Compressor Station and Jal No. 3 which both assume 25-year life of controls for LEC.
[368] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Processing Plant Appendix B.

overcome does not mean that the technology is not feasible or that the resulting emissions reductions are not warranted.

3. Use of SCR

Harvest Four Corners did not evaluate SCR for Units 16, 17, and 18 primarily because it claimed that it was not technically feasible for these engines.[369] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for these engines.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[370]

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[371] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[372] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

IX. El Paso Natural Gas Company LLC - Pecos River Compressor Station

The Pecos River Compressor Station is a natural gas compressor station located approximately 12 miles south/southeast of Malaga, New Mexico in Eddy County. It is owned/operated by El

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[369] *Id.* at 2-8.
[370] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[371] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[372] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

Paso Natural Gas Company (EPNG). The facility consists of three GE Frame 3 Regenerative Cycle Turbines that each have a capacity of 7,150 hp.[373]

In EPNG's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Natural Gas-Fired Regenerative Cycle Turbine (Units A-01, A-02, and A-03)[374]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[375] The following provides a review of the company's four-factor analyses.

A. Interest Rate Used in Cost Analyses.

EPNG used a 5.5% interest rate in the cost analyses for all of the controls evaluated in its 4-factor analyses.[376] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. This is the same interest rate that EPA has used in its cost spreadsheet for SCR, but EPA also states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[377] The current bank prime rate is 3.25%.[378] The highest the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[379] In a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[380] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. For these reasons, in the cost effectiveness calculations provided herein, a 4.7% interest rate is used rather than a 5.5% interest rate.

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[373] Title V Operating Permit P129R3 for Pecos River Compressor Station at 3.
[374] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at 1-2.
[375] *Id.*
[376] *Id.* at 8-6.
[377] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[378] https://www.federalreserve.gov/releases/h15/.
[379] https://fred.stlouisfed.org/series/DPRIME.
[380] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.

B. GE Regenerative Cycle Turbines (Units A-01, A-02, and A-03) of Pecos River Compressor Station

As stated above, the three turbines evaluated for controls are GE Frame 3 Regenerative Cycle Turbines with capacity of 7,150 hp. These units were all manufactured in 1953.[381] Under the terms of the permit, the units are each subject to the following hourly and annual emission limits of NOx: 53.1 lb/hr and 232.6 tpy.[382]

EPNG evaluated one control option for these turbines aside from the good combustion practices which the company indicated were currently being utilized at the units. The other combustion control type of controls considered by EPNG included a Lean Head End (LHE) combustion liner, dry low NOx combustors, water/steam injection, but El Paso claimed that based on communications with GE, none of these controls were an option for the Pecos River Compressor Station turbines.[383] Thus, the company only evaluated SCR for the turbines. The following provides comments on the company's four-factor analysis of SCR.

1. Baseline Emissions for the Units A-01, A-02, and A-03 Combustion Turbines.

EPNG states that its cost effectiveness analyses for SCR were based on actual emissions using 2016 stack test data and actual hours of operation from the 2016 emission inventory submittal.[384] In its cost data sheets in Section 8.0 of its four-factor analysis, the company provided summaries of the 2016 test data and the 2016 annual NOx tons per year from each unit, from which the actual operating hours could then be calculated.[385] NMED and EPNG should review other stack tests for these units to ensure that the actual emission rates can be considered to truly reflect actual emissions over the lifetime of the controls being evaluated. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on an estimate of emissions expected in 2028.

2. Evaluation of SCR for the Regenerative Cycle Turbines at Pecos River Compressor Station

EPNG evaluated SCR to achieve 70% reduction in NOx emissions, assuming a 20-year life of SCR.[386] With respect to the lifetime of an SCR, EPA's Control Cost Manual indicates that the life of an SCR at a gas turbine used in an industrial setting like a compressor station.[387] Thus, to be consistent with EPA's current Control Cost Manual chapter on SCR, a 25-year life of SCR should have been assumed.

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[381] Title V Operating Permit P129R3 for Pecos River Compressor Station at 5.
[382] *Id.*
[383] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at 3-1.
[384] *Id.* at 3-1.
[385] *Id.* at Appendices C and D.
[386] *Id.*, Section 8.0 (at pdf page 31, 36, and 41.
[387] *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80.

EPNG only assumed 70% control with SCR at Units A-01, A-02, and A-03 and cites to an older EPA Fact Sheet on SCR.[388] A review of that EPA fact sheet, which appears to be from 2003, shows that EPA assumed SCR could achieve 70-90% NOx control, and EPA assumed 85% control in its example cost effectiveness analysis of the 2003 Fact Sheet. In EPA's June 2019 updated chapter on selective catalytic reduction in its Control Cost Manual, EPA states that "[t]heoretically, SCR systems can be designed for NOx removal efficiencies [of] close to 100 percent. In practice, commercial coal-, oil-, and natural gas-fired SCR systems are often designed to meet control targets of over 90 percent."[389] EPNG did not provide any other justification for assuming only 70% control with SCR at the Pecos River Compressor station turbines. Indeed, ninety percent control has been the benchmark of SCR NOx removal efficiency expected with SCR including at natural gas-fired combustion turbines.[390] As discussed in NPCA's Oil and Gas Four-Factor Report, in a 2000 analysis of SCR cost effectiveness from an uncontrolled gas turbine, NESCAUM estimated that a 15 ppmvd NOx rate reflective of 90% NOx control (from uncontrolled NOx rates) could be achieved with SCR.[391]

EPNG used the SCR cost spreadsheet that EPA has made available with the Control Cost Manual to estimate SCR costs for its combustion turbines.[392] However, EPNG stated that the exhaust system would require significant modifications to install the catalyst, requiring the stack to be moved and additional ducting.[393] EPNG also states that it believes there is insufficient room within the existing building that houses the turbines, and thus has included costs to modify the turbine housing in the cost analysis.[394] Presumably, to account for some of this, EPNG applied a 1.5 retrofit factor in EPA's SCR cost spreadsheet, and also EPNG also included an additional $2.5 million would be required per combustion turbine for building modifications. However, as previously stated above, there have been numerous SCR retrofits installations at various industrial facilities that have had to overcome space constraints and retrofit difficulties. Indeed, a report about SCR retrofits at GE LM2500 turbines at Chevron's Eastridge Cogeneration plant in California showed that some significant changes to the facility had to be made to accommodate SCR, including cutting the duct between economizers and moving the stack and one economizer onto new foundations to make way for the SCR reactor.[395] EPA's SCR cost spreadsheet has an option to indicate whether the SCR installation is a new installation or a retrofit, and SPNG selected "retrofit." EPA's SCR chapter in its Control Cost Manual already provides for a 25% increase in cost above the cost of SCR at a new greenfield coal-fired boiler,

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[388] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at 3-1.
[389] *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 5.
[390] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand Curve Reset, prepared for New York Independent System Operator, Inc., at 5 and at 11-12, available at: http://files.brattle.com/files/7644_independent_evaluation_of_scr_systems_for_frametype_combustion_turbines.pdf.
[391] NESCAUM 2000 Status Report at III-21 through III-24 and at III-40 (see references 11, 16, 9, 14, and 15).
[392] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at 3-1.
[393] *Id.*
[394] Id.
[395] *See* Seebold, James et al., Gas Turbine NOx Reduction Retrofit, , available at https://www.onepetro.org/conference-paper/SPE-66501-MS.

which is reflected in EPA's SCR cost spreadsheet, because EPA's spreadsheet calls for use of a "0.8" retrofit factor for an SCR installation at a new facility and a "1" retrofit factor for an average SCR retrofit.[396] Further, given that most gas turbines that have retrofitted an SCR reactor likely were not planned or designed for an SCR reactor to be installed, the average retrofit costs that EPA's SCR cost spreadsheet calculates likely take into account some of the difficulties like the need to move the exhaust stack to install the SCR, which would be required for most if into all SCR retrofits to gas turbines.[397] Thus, EPNG was not justified in using both a 1.5 retrofit factor in the SCR cost spreadsheet and also adding $2.5 million in capital costs per unit for compressor building modifications.

With respect to the compressor building modifications, there is one entry made by EPNG into the EPA cost spreadsheet that ultimately defines the size of the SCR reactor, and that is the "base case fuel gas volumetric flow rate factor" which is in terms of ft^3/min-MMBtu/hr. EPNG used a fuel gas volumetric flow rate factor of 35,103.70 ft^3/min-MMBtu/hr for Unit A-01, 50,483.81 ft^3/min-MMBtu/hr for Unit A-02, and 45,807.42 ft^3/min-MMBtu/hr for Unit A-03, which they state is "[c]alculated based on the estimated actual annual fuel consumption and maximum heat input rate."[398] These numbers seem very high in comparison to the values EPA uses for coal-fired boilers for which EPA defines as a constant for fuel type regardless of unit size or actual gas throughput.[399] EPNG's fuel gas volumetric flow rate factors for each combustion turbine are roughly a factor of 100 higher than the fuel gas volumetric flow rate factors used by EPA in its SCR cost spreadsheet for coal-fired boilers. Given that the fuel gas volumetric flow rate factor is used to determine the size of SCR reactor required, it is imperative that NMED ensure that an accurate fuel gas volumetric flow rate factor for natural gas-fired combustion turbines is used in the SCR cost spreadsheet. Presumably, EPNG relied on the reactor size calculations of the spreadsheet to estimate the cost of $2.5 million per SCR installation for modifying the compressor building.

With respect to the cost to modify the compressor building, it appears that EPNG included the $2.5 million per SCR to modify the compressor building with the capital costs of SCR in determining total annual costs of the control.[400] This reflects a 65% increase in the capital cost of SCR that was calculated using a 1.5 retrofit factor. However, while the life of the SCR might be only 25 years, the life of the modifications to the compressor building would likely last as long as the compressor station is in operation, which has been 65 years so far "without any significant deterioration in operating efficiency [of the combustion turbines],[401] and EPNG anticipates that the life of the turbines will be longer than the SCR. Thus, EPNG's approach significantly increases the capital cost and thus the cost effectiveness of SCR for building

[396] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction at pdf page 66.
[397] *See* EPA Control Cost Manual, Section 1, Chapter 2 – Cost Estimation: Concepts and Methodology, at 27.
[398] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at pdf page 32, pdf page 37, and pdf page 42.
[399] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction at pdf page 59, Table 2.6.
[400] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at 2-6.
[401] *Id.* at 5-2.

modifications that will have a useful life much longer than the 25 years that EPA assumes for SCRs at industrial facilities.

To attempt to address some of these issues, as well as to revise the cost effectiveness to reflect a 4.7% interest rate and a 25-year life, EPA's SCR cost spreadsheets were used to calculate SCR cost to meet a NOx emission rate of 15 ppmv (reflective of 82 to 86% NOx removal at the Pecos River turbines)[402] assuming a 25-year life and a 4.7% interest rate. No retrofit factor was used in EPA's cost spreadsheets for the reasons previously described, but an analysis was done adding in the company's projected $2.5 million capital cost to the total SCR capital costs. Although the life of the modified compressor building would be much longer than 25 years, the $2.5 million was amortized at the same 25-year life as the SCR. No other changes were made to any of EPNG's inputs to the SCR spreadsheet. The results of these analyses are provided below.

Table 25. Cost Effectiveness of SCR at Pecos River Compressor Station Units A-01, A-02, and A-03 Combustion Turbines, Using a 25-year Life, 4.7% Interest Rate, Retrofit Factor of 1, and EPNG's Assumptions for all Other Inputs

Unit	Assumed NOx Removal Efficiency to meet 15 ppm NOx rate	Capital Cost of SCR (2018 $)	Annual O&M Costs	NOx Removed from 2016 Baseline, tpy	Cost Effectiveness of SCR (2018 $), $/ton	Cost Effectiveness of SCR with Building Modifications (2018 $), $/ton
A-01	82%	$2,535,199	$33,780	42	$5,007/ton	$9,104/ton
A-02	86%	$2,535,199	$43,109	82	$2,676/ton	$4,775/ton
A-03	86%	$2,535,199	$48,533	101	$2,230/ton	$3,934/ton

The above table provides cost effectiveness for SCR by itself at Units A-01, A-02, and A-03 as well as SCR plus the EPNG's estimated $2.5 million capital cost per SCR to modify the compressor building. As the table shows, including EPNG's estimated cost to modify the compressor building for each SCR installation significantly increases the cost effectiveness of SCR. For the reasons stated above, it is imperative that NMED ensure that the costs to modify the compressor building were appropriately estimated. Regardless, for at least Units A-02 and A-03 which operated more than Unit A-01 in 2016, SCR should still be considered cost effective even with $2.5 million in costs per SCR to modify the building. And if 2016 operating hours were lower than typical operation for Unit A-03, SCR should be considered cost effective for that unit as well.

[402] This was determined by converting EPNG's stated uncontrolled lb/MMBtu NOx rates to ppm NOx rates using the conversions of EPA's 1993 ACT for Gas Turbines (*See* EPA, 1993 ACTfor Gas Turbines at Appendix A which has conversion equations for natural gas-fired combustion turbines) and determining the percent NOx reduction efficiency to achieve a 15 ppmv NOx limit (equivalent to ~0.060 lb/MMBtu).

EPNG expressed concerns with the ammonia reagent used in an SCR system.[403] As discussed in the NPCA Oil and Gas Four-Factor Report, the primary concerns with ammonia releases are when anhydrous ammonia is used for the reagent.[404] EPNG assumed 29% aqueous ammonia in its SCR analyses.[405] When aqueous ammonia, or urea, is used, the hazards from transporting and storing pressurized ammonia don't apply. SCR has been installed at numerous industrial facilities across the U.S. There are well-established protocols and procedures for safely transporting, storing, and using anhydrous ammonia at facilities that use that reagent in their SCR systems.

X. DCP Midstream - Linam Ranch Gas Plant

The Linam Ranch Gas Plant is a natural gas processing plant located about seven miles west of Hobbs, New Mexico in Lea County. The plant is owned/operated by DCP Midstream LP. According to the Title V permit for the plant, the facility processes natural gas by removing hydrogen sulfide, water, and carbon dioxide from field gas and separates natural gas liquids from the field gas stream.[406] NMED's Statement of Basis for the plant's Title V permit describes the plant as follows: "The plant consists of an Inlet Receiving System, Amine Treater, Acid Gas Injection Well, Inlet Compression and Dehydration System, Cryogenic/Turbo Expander Plant with external Propane Refrigeration, Residual Compression, and Product Sales for Residue Gas, NGL Liquids, Stabilized Oil, Slop Oil, and Molten Liquid Sulfur."[407] The plant include Fuel Gas Systems, Instrument and Starting Air Systems, a Heat Medium (Hot Oil) System, Cooling Towers, Process Flare, Acid Gas Flare, and Drain Systems. Processing operations at the plant include chemical reaction processes, thermodynamic processes, and physical processes."[408]

According to the Title V permit, the Linam Ranch Gas Plant includes several 2-stroke lean burn RICE, several natural gas-fired turbines, boilers, a heater, gas sweetening equipment (amine unit, sulfur recovery unit (SRU) incinerator, acid gas and SRU flares), and other emission units.[409] In DCP Midstream's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Clark TLA-6 2-stroke lean-burn RICE: Units 6-11
- Solar Centaur Turbines: Units 29, 30, 31, and 32B.[410]

[403] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at 5-1.
[404] March 2020 NPCA Oil and Gas Four-Factor Report at 80. *See also* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction at pdf page 15.
[405] November 2019 Regional Haze Four-Factor Analysis for the Pecos River Compressor Station at pdf page 32, pdf page 37, and pdf page 42.
[406] Title V Operating Permit P094-R2 for Linam Ranch Gas Plant at 3.
[407] NMED Statement of Basis – Narrative, Title V Permit, Linam Ranch Gas Plant, March 2015, at 1.
[408] NMED Statement of Basis – Narrative, Title V Permit, for Permit Nos. 0044-M-10-M10R6 and P086-R3, at 1.
[409] Title V Operating Permit P094-R2 for Linam Ranch Gas Plant at 7-8.
[410] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Linam Ranch Gas Plant at 1-2.

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[411] The following provides a review of the company's four-factor analyses.

A. Interest Rate Used in Cost Analyses.

DCP Midstream used a 5.5% interest rate in the cost analyses for all of the controls evaluated in its 4-factor analyses.[412] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. This is the same interest rate that EPA has used in its cost spreadsheet for SCR, but EPA also states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[413] The current bank prime rate is 3.25%.[414] The highest the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[415] In a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[416] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. For these reasons, in the cost effectiveness calculations provided herein, a 4.7% interest rate is used rather than a 5.5% interest rate.

B. Clark TLA Two-Stroke Lean Burn RICE (Units 6-11) of the Linam Ranch Gas Plant

Units 6 and 7 are Clark TLA-6 two-stroke lean-burn RICE that were constructed in 1974, each with a capacity of 2,000 hp.[417] Units 6 and 7 each have an hourly NOx limit of 39.3 lb/hr; units 6-11 have a combined annual NOx limit of 566 tpy.[418]

Units 8 through 11 are Clark HBA-6 two-stroke lean-burn RICE that were constructed in 1951, each with a capacity of 1,267 hp.[419] Units 8 through 11 each have an hourly NOx limit of 47.5 lb/hr; units 6-11 have a combined annual NOx limit of 566 tpy.[420]

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[411] *Id.*
[412] *Id.* at Section 8.0 Supporting Documentation.
[413] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[414] https://www.federalreserve.gov/releases/h15/.
[415] https://fred.stlouisfed.org/series/DPRIME.
[416] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.
[417] Title V Operating Permit P094-R2 for Linam Ranch Gas Plant at 7.
[418] *Id.* at 9.
[419] *Id.* at 7.
[420] *Id.* at 9.

1. Use of Low Emission Combustion Technology

DCP Midstream determined that, "…clean burn technology retrofits are physically possible yet deemed technically infeasible for the engines at Linam. The aforementioned available clean burn control technologies are incapable of being retrofit on the existing 70-year-old engines on site."[421] It's true that Units 8 through 11 are 69 years old but units 6 and 7 are newer units and, in fact, units of similar ages to all of these units at Linam Ranch have demonstrated LEC retrofit technology to reduce NOx emissions. For example, Targa's Eunice and Monument gas plants operate Clark engines of similar vintage to the ones at Linam Ranch and submitted four-factor analyses to NMED for Clean Burn technology retrofits, which Targa deemed to be feasible control options.[422]

More generally, the following additional information regarding NOx emission rates specific to Clark TLA model engines – both uncontrolled and with LEC technology – are provided here:

- EPA's 2000 RICE Update includes NOx emissions test data for specific engines, including Clark Model TLA-6, 2-stroke, lean-burn, 2,000 hp RICE retrofitted with LEC. According to EPA, six engines retrofitted by a third-party vendor had NOx emission rates ranging from 0.8–1.4 g/bhp-hr, with a mean of 1.0 g/bhp-hr.[423]

- An evaluation by a technical group for the Pipeline Research Council International looked at three of the most representative make / models of 2-stroke lean burn compressor engines: (1) 2,250 hp Cooper GMVH-10; (2) 2,000 hp Clark TLA-6; and (3) 2,500 hp Cooper GMW-10. According to a technical report by the Ozone Transport Commission (OTC) describing this evaluation, "[t]he evaluation concluded that there were no technology gaps and that each of the three makes/models evaluated were capable of attaining a NOx emissions limitation of 0.5 g/bhp-hr using a combination of improvements and retrofits related to air supply, fuel supply, ignition, electronic controls, and engine monitoring."[424]

- In 2002, EPA collected data on emission rates of lean burn engines that have been retrofitted with LEC, including data from several state agencies for specific engine

[421] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Linam Ranch Gas Plant at 2-9.
[422] Targa's Eunice Gas Plant operates several Clark BA-6 and HBA-T8 2SLB RICE constructed in 1984 and capable of being retrofit with LEC technology. Targa's Monument Gas Plant operates several Clark RA-6, RA-8, and HRA-8 2SLB RICE constructed in 1956 and 1969 and capable of being retrofit with LEC technology.
[423] EPA 2000 RICE Update at 4-8.
[424] Ozone Transport Commission, Technical Information, Oil and Gas Sector, Significant Stationary Sources of NOx Emissions, Final, October 17, 2012, p. 24, *available at*: https://otcair.org/upload/Documents/Meeting%20Materials/Final%20Oil%20%20Gas%20Sector%20TSD%2010-17-12.pdf [hereinafter referred to as "2012 OTC Report"].

models.[425] Test results for 20 Clark TLA engines ranged from 0.4 to 2.9 g/hp-hr, with an average controlled NOx rate of 1.5 g/hp-hr.[426]

The above references don't specify the age of the engines retrofit with LEC technology but NMED should require DCP Midstream to further explore additional third-party vendor options for retrofitting these units.

A recent Interstate Natural Gas Association of America (INGAA) Report provides some information on Clark TLA engine stock components and retrofit modification / upgrade options.[427] Examples from this report include: upgrading stock turbocharger and stock intercooler systems; upgrading stock low pressure direct fuel systems to high pressure fuel injection and control systems; and upgrading controls for the stock fuel system.[428] Based on the information in this report, Clark TLA model engines come equipped with a single turbo, an intercooler system, and a low pressure direct fuel system. The INGAA report evaluated controls for various regulatory scenarios that would achieve NOx emission levels in the 1–3 g/hp-hr range.[429]

LEC retrofit costs specific to Clark TLA model engines are reported in the INGAA report, ranging from $300–$600 per hp, for upgrades to the scavenging, intercooler, and fuel systems.[430] The INGAA report doesn't specify what year the cost data are from so we assume it reflects the timeframe of the report, or 2017$. Using these cost data, we can estimate the cost effectiveness of retrofitting Units 6 through 11 at the Linam Gas Plant. Retrofit cost estimates using INGAA's cost estimate would range from $600,000–$1,200,000 for the 2,000 hp units 6 and 7 and $380,000–$760,200 for the 1,267 hp units 8 through 11, in 2017$. Using the Chemical Engineering Plant Cost Indices, these costs would increase to $640,000–$1,275,000 and $400,000–$800,000, in 2018$.[431] It's not clear if operating costs are included in these INGAA cost estimates; to be conservative, annual operating costs of the LEC controls are assumed to be 15% of capital costs.[432]

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[425] *See* EPA Stationary Reciprocating Internal Combustion Engines Technical Support Document for NOx SIP Call (October 2003) at 15, *available at:* http://www.valleyair.org/workshops/postings/2011/8-18-11-rule4702/R4702%20APPF.pdf

[426] *Id.* Table 4.

[427] INGAA, Report No. 2016-6, *Potential Impacts of the Ozone and Particulate Matter NAAQS on Retrofit NOx Control for Natural Gas Transmission and Storage Compressor Drivers* (December 2017), *available at:* https://www.ingaa.org/File.aspx?id=33789.

[428] *Id. See, e.g.,* Table 6 at 18.

[429] *Id.* at 23.

[430] *Id.*

[431] Based on multiplying the cost estimate from the 2017 INGAA report by the ratio of the CEPCI indices for 2018 to 2017 (603.1/567.5).

[432] This assumption is consistent with cost data provided for the October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9, however it results in much higher O&M costs than those used in Targa's (Eunice, Monument, and Saunders Gas Plants) and Harvest Four Corners' (Kutz Canyon Gas Plant) four-factor analyses—which ranged from $40,000/yr to $100,000/yr—and than those used for ETC Texas Pipeline's Jal No. 3 Gas Plant, which assumed O&M costs would be 13% of capital costs.

EPA has examined source test data from large natural gas-fired lean burn engines and has affirmed that these data support an uncontrolled emission rate from these engines, generally, of 16.8 g/hp-hr.[433] More specifically, these source test data include individual data for three Clark TLA engines with uncontrolled emission rates of 16 g/hp-hr and two Clark TLA-10 engines with uncontrolled emission rates of 7 g/hp-hr.[434] The allowable hourly NOx emission rates for the units at Linam Ranch are equivalent to 9 g/hp-hr (for units 6 and 7) and 17 g/hp-hr for units 8 through 11. NPCA's March 2020 Oil and Gas Four-Factor Report stated that a wide range of emission rates are achievable with LEC technology, with NOx emissions generally no higher than 2 g/hp-hr and often significantly lower (e.g., as low as 0.5 g/hp-hr).[435] Retrofitting LEC technology on the units at Linam Ranch to achieve a controlled NOx rate of 2 g/hp-hr reflects a 78-88% emissions reduction from the sources' allowable NOx rates. Baseline NOx emissions for these units at Linam Ranch were not provided in DCP Midstream's four-factor submittal.
The cost effectiveness of retrofitting these engines with LEC to meet a 2 g/hp-hr NOx emissions rate, based on uncontrolled emission rates (no higher than what is permitted for this source), is presented in the table below. Since the operating schedule for these engines at the Linam Gas Plant is unknown we present cost effectiveness for 2,000 and 4,000 operating hours per year; the permitted annual NOx emission rate cap for these units of 566 tons per year indicates that the units likely wouldn't operate much more than 4,000 hours per year, on average. Note, this analysis uses an interest rate of 4.7%, reflective of current and likely near future interest rates.[436] Further note, the LEC controls are assumed to last 25 years, consistent with other cost effectiveness analyses submitted to NMED for LEC controls.[437]

[433] *See* EPA Stationary Reciprocating Internal Combustion Engines Technical Support Document for NOx SIP Call (October 2003) at 5, *available at:* http://www.valleyair.org/workshops/postings/2011/8-18-11-rule4702/R4702%20APPF.pdf.
[434] *Id*. at 6 and 7.
[435] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 28.
[436] As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.
[437] See 2019 Four-Factor submittals for Roswell Compressor Station and Jal No. 3 which both assume 25-year life of controls for LEC.

Table 26. Cost Effectiveness of LEC at Uncontrolled Linam Gas Plant Units 6 through 11 to Reduce NO_x Levels to 2 g/hp-hr, Assuming a 4.7% Interest Rate and a 25-Year Life, 2018$

Unit	Capital Cost of LEC to Reduce NOx from Uncontrolled Rate	Annual O&M Costs (assume 15% of Capital Costs)	Total Annualized Costs of LEC to Reduce NOx to 2 g/hp-hr (78-88% NOx Reduction)	NOx Removed, tpy operating 2,000 hr/yr	Cost Effectiveness of LEC operating 2,000 hr/yr, $/ton	NOx Removed, tpy operating 4,000 hr/yr	Cost Effectiveness of LEC operating 4,000 hr/yr, $/ton
6	$640,000–$1,275,000	$96,000–$191,000	$140,000–$280,000	31	$4,521/ton—$9,042/ton	62	$2,260/ton–$4,521/ton
7	$640,000–$1,275,000	$96,000–$191,000	$140,000–$280,000	31	$4,521/ton—$9,042/ton	62	$2,260/ton–$4,521/ton
8	$1,083,986–$2,167,972	$162,598–$325,196	$237,213–$474,426	41	$2,138/ton—$4,277/ton	83	$1,069/ton–$2,138/ton
9	$1,083,986–$2,167,972	$162,598–$325,196	$237,213–$474,426	41	$2,138/ton—$4,277/ton	83	$1,069/ton–$2,138/ton
10	$1,083,986–$2,167,972	$162,598–$325,196	$237,213–$474,426	41	$2,138/ton—$4,277/ton	83	$1,069/ton–$2,138/ton
11	$1,083,986–$2,167,972	$162,598–$325,196	$237,213–$474,426	41	$2,138/ton—$4,277/ton	83	$1,069/ton–$2,138/ton

LEC at these units would be even more cost effective than what is shown if retrofits at these engines could meet even lower NOx emission levels, less than 2 g/hp-hr. DCP Midstream indicated that retrofitting engines at the Linam Gas Plant is physically possible and NMED should require that the company solicit specific vendor quotes in order to assess the cost effectiveness of reducing NOx emissions from these engines, as has been done by other companies in New Mexico with similar engines.

2. Use of SCR

DCP Midstream did not evaluate SCR for Units 6 through 11 primarily because it claimed that it was not technically feasible for these engines.[438] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be

[438] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Linam Ranch Gas Plant at 2-9.

summarily dismissed as not feasible for these engines, particularly because DCP Midstream has not found LEC to be a cost effective NOx reduction strategy for these units.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[439]

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[440] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[441] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

C. Solar Centaur Natural Gas-Fired Combustion Turbines (Units 29, 30, 31, and 32B) of the Linam Ranch Gas Plant.

The combustion turbines evaluated at the Linam Ranch Gas Plant are Solar combustion turbines of the following models, horsepower capacities, and manufacture date:[442]

Unit 29	Solar T-70	77.6 MMBtu/hr	1995
Unit 30	Solar Taurus T-70	73.95 MMBtu/hr	1995
Unit 31	Solar T4700	36.8 MMBtu/hr	1995
Unit 32B	Solar T4000	36.2 MMBtu/hr	1979

The units are all subject to NOx limits in 40 C.F.R. Part 60, Subpart GG, but those specific limits are not detailed in the Title V permit.[443] Under the terms of the permit, the units are also subject to the following hourly and annual emission limits of NOx.

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[439] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[440] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[441] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[442] *See* Title V Operating Permit P094-R2 for Linam Ranch Gas Plant at 8.
[443] *Id.* at 10.

Table 27. Limits from DCP Midstream Title V Permit for the Linam Ranch Plant Combustion Turbines[444]

Combustion Turbine Unit ID	NOx limit, lb/hr	NOx limit, tpy
29	11.8	51.8
30	11.3	49.3
31	26.0	114
32B	23.7	103.9

DCP Midstream evaluated two control options for these combustion turbines: Solar's SoLoNOx combustion system and SCR.

1. Baseline Emissions for Units 29, 30, 31, and 32B.

DCP Midstream states that its cost effectiveness analyses for SoLoNOx and SCR were based on 2016 turbine operating hours multiplied by the permitted potential to emit rate (lb/hr).[445] However, the company did not provide the operating hours or this calculation of 2016 emissions in its four-factor analysis. The company also provided analyses of cost effectiveness of controls "[u]sing the actual emissions testing data (NSPS KKKK) for these turbines, rather than [potential to emit]."[446] However, the company provided no data in its four-factor analyses as to what the actual emission testing results were. Further confusing the matter is that, based on a review of the permit, the turbines are not subject to NSPS KKKK. Instead, all of the units are subject to NSPS Subpart GG.[447] A review of Title V permit application data for the Linam Ranch Gas Plant on the NMED's Emissions Analysis Tool did not find any other emissions testing data available for these units. NMED must make available whatever test data is being relied on to reflect actual emissions of these five combustion turbines if NMED intends to rely on the cost effectiveness analyses provided in a footnote of DCP Midstream's four-factor analysis. NMED should present information on the test data so the circumstances of the stack tests can be reviewed.

According to DCP Midstream's four-factor analysis, its 2016 emission inventory is based on its actual operating hours multiplied by its hourly NOx emission limit.[448] Given that this is how DCP Midstream reports actual emissions for the combustion turbines to NMED and in the absence of testing documentation to ensure that the test data DCP relies on for its alternative baseline analysis reflects actual emissions at all levels of operation of the combustion turbines, it seems most appropriate to use the data that DCP has been using for its emission inventory. NMED should require that DCP identify the operating hours of each unit that it has assumed for the combustion turbines.

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[444] *Id.* at 9.
[445] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Linam Ranch Gas Plant at 3-11, fn 23.
[446] *Id.*
[447] Title V Operating Permit P094-R2 for DCP Midstream Linam Ranch Gas Plant at 6, Table 103.A.
[448] *Id.* at 3-11.

2. Evaluation of SoLoNOx for the Combustion Turbines at 29, 30, 31, and 32B.

DCP Midstream states that SoLoNOx can achieve an "overall reduction efficiency of 55%-80%...for the turbines located at this facility using this technology in comparison to permitted [potential to emit]."[449] Specifically, DCP Midstream evaluated SoLoNOx to meet a 15 ppm NOx rate at Units 29 and 30 and a 25 ppm NOx rate at Units 31 and 32B.[450]

In terms of the life of SoLoNOx controls in the cost effectiveness analyses, DCP's analysis assumed a 20 year life. For the reasons described above on the evaluation of dry low NOx combustors at the gas turbines at the Chaco Gas Plant, a 25-year life is a more appropriate assumption for the cost effectiveness analysis.[451] In the table below, DCP Midstream's cost effectiveness analyses of SoLoNOx were revised to take into account a longer lifetime of controls and a lower 4.7% interest rate.

Table 28. Revised Cost Effectiveness of SoLoNOx at Units 29, 30, 31 and 32B of the DCP Midstream Linam Ranch Gas Plant, to Reflect a 4.7% Interest Rate and a 25 Year Life

Unit	DCP's Total Annual Costs of SoLoNOx (at 5.5% Interest and 20-Year Life)	DCP's Cost Effectiveness at 5.5% Interest and 20 Year Life	Revised Total Annual Costs of SoLoNOx	Revised Cost Effectiveness at 4.7% Interest and 25 Year Life
29	$605,743	$21,278/ton	$602,950	$20,642/ton
30	$618,799	$23,829/ton	$616,006	$23,720/ton
31	$269,048	$3,100/ton	$248,594	$2,865/ton
32B	$268,805	$12,765/ton	$248,151	$11,794/ton

The cost effectiveness of SoLoNOx at Units 29 and 30 are very high, because according to DCP Midstream's four-factor submittal, the units' current NOx rates are 33-35 ppm, and thus SoLoNOx to reduce the units' NOx emissions to 15 ppm will only reduce emissions by 55-57%. For Unit 31, SoLoNOx is much more cost effective at $2,865/ton, as the company's four-factor submittal shows that SoLoNOx at Unit 31 would reduce NOx by 78%. For Unit 32B, the cost effectiveness is higher despite SoLoNOx being projected to reduce NOx by 76% because the unit had low actual emissions in 2016 (which appears to be due to low operating hours). NMED should ensure that the 2016 emissions and operational data that is being relied on for the cost effectiveness analyses is reflective of historical operations and projected operations in 2028 before discounting a highly effective control as not cost effective.

[449] *Id.* at 2-4.
[450] *Id.* at pdf page 29, pdf page 34, pdf page 39, and pdf page 44.
[451] *See also* NPCA March 2020 Oil and Gas Four-Factor Report at 69-70.

3. Evaluation of SCR for Units 29, 30, 31, and 32B of the DCP Midstream Linam Ranch Gas Plant.

DCP Midstream evaluated SCR as a technically feasible control option for the Solar Centaur gas combustion turbines of Units 29, 30, 31, and 32B of the DCP Midstream Linam Ranch Gas Plant. DCP Midstream used EPA's SCR cost spreadsheet made available with EPA's Control Cost Manual.[452]

DCP Midstream only assumed 70% control could be achieved with SCR at Units 29, 30, 31, and 32B, even though the company indicated that SCR could achieve up to 90% control.[453] As presented NPCA's Oil and Gas Four-Factor Report, NESCAUM assumed 90% control with SCR in its 2000 Status Report to control small gas turbines down to 15 ppmv.[454] However, for Units 29 and 30, a 15 ppm NOx rate with SCR only reflects 55-57% control. As discussed in Section I.C.2 above, NOx rates as low as 3.75 ppm have been permitted for gas turbines with SoLoNOx and SCR.[455] Thus, to reflect the capabilities of SCR at Units 29 and 30, a much lower NOx emissions rate should have been evaluated for these units. For this report, the EPA's SCR cost spreadsheet was thus used with almost all of the same data inputs as used by DCP Midstream, but assuming a NOx rate equivalent to about an 85% NOx reduction would be met at the units (approximately a 5 ppm NOx emission rate at Units 29 and 30 and 15 ppmv NOx emission rate at Units 31 and 32B). The only other changes made to DCP's SCR spreadsheet inputs were to assume a longer life of the SCR of 25-years[456] and a 4.7% interest rate (instead of DCP's assumed 20-year life of SCR and 5.5% interest rate). The table below provide the estimated cost effectiveness of SCR to achieve 85-87% control at Units 29, 30, 31, and 32B of the DCP Midstream Linam Ranch Gas Plant.

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[452] November 2019 Regional Haze Four-Factor Analysis for DCP Midstream Linam Ranch Gas Plant at 3-12.
[453] *Id.* at 2-6.
[454] NPCA March 2020 Oil and Gas Four-Factor Report at 74-75. *See also* NESCAUM, December 2000, Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, Technologies & Cost Effectiveness at III-21 through III-24 and at III-40 (see referenced 11, 16, 9, 14, and 15), available at http://www.nescaum.org/documents/nox-2000.pdf/view.
[455] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.
[456] EPA's Control Cost Manual indicates that SCR at industrial units has a life of 25-years. *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80.

Table 29. Cost Effectiveness of SCR to Achieve ~85% NOx Reduction (5 ppmv at Units 19 and 20 and 15 ppmv at Units 21 and 22B) at the Linam Ranch Gas Plant, Assuming a 25-Year Life of SCR and a 4.7% Interest Rate

Linam Ranch Unit #	Capital Cost of SCR	Annual Operational and Maintenance Costs of SCR	Annualized Cost of SCR to Achieve 85-87% NOx control	NOx Emission Reductions, tpy	Cost Effectiveness of SCR to Achieve 85-87% Control (at 4.5% interest rate and 25 year life)
19	$3,029,516	$50,364	$261,605	44	$5,991/ton
20	$2,935,376	$47,267	$252,025	39	$6,395/ton
21	$1,864,898	$34,660	$165,705	97	$1,706/ton
22B	$1,845,408	$18,703	$148,406	24	$6,195/ton

As shown by a comparison of Table 29 to Table 28 above, SCR at the Linam Ranch Gas Plant Units 19, 20, 21, and 22B is actually more cost effective than SoLoNOx at the units and SCR can achieve greater levels of NOx reductions. SCR could be even more cost effective if there are opportunities to share an SCR between two or more combustion turbines.
Moreover, SCR combined with SoLoNOx, which is commonly required to meet BACT for gas turbines, could reduce NOx by 97% or more. As discussed in Section I.C.2 of this report, this combination of NOx controls has been permitted for the Buckingham Compressor Station to achieve a NOx emission rates of 3.75 ppmv @ 15% oxygen.[457] However, emission rates with SoLoNOx and SCR at gas-fired combustion turbines could be even lower, as BACT or LAER for such turbines operated for power generation are generally set at 2 to 2.5 ppmv at 15% oxygen.[458] NMED should require DCP Midstream to evaluate the cost effectiveness of the combination of SoLoNOx and SCR to achieve the greatest level of NOx reduction.

XI. ETC Texas Pipeline – Jal No. 3 Gas Plant

The ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant is located in Lea County. NMED has described the facility processes as follows:

> The function of the facility is to treat and process natural gas. The facility consists of natural gas compression units, amine-sweetening units, a sulfur unit, an acid

[457] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.
[458] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand and Curve Reset, at 9.

gas reinjection system, various storage tanks, fugitive emissions, and three flares.[459]

According to the permit, the plant includes several 2-stroke and 4-stroke lean-burn reciprocating internal combustion engines (RICE), boilers, heaters, amine sweetening units, vapor recover unit and thermal oxidizer, flares, and tanks.[460] In ETC Texas Pipeline's four-factor submittal, the company evaluated air pollution controls for the following emission units:

- Cooper-Bessemer 2SLB RICE GMV-10T5: Units 4A and 5A.[461]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[462] The following provides a review of the company's four-factor analyses.

A. Units 4A and 5A: Cooper-Bessemer GMV-10T5 2-Stroke Lean-Burn RICE

Units 4A and 5A are two-stroke lean-burn RICE that were constructed in 1948, each with a capacity of 1,100 hp.[463] The units each have an hourly NOx limit of 27.9 lb/hr and an annual NOx limit of 122.0 tpy.[464] The operating hours for these units, based on 2016 emissions inventory data are 560 hours per year for unit 4A and 4,290 hours per year for units 5A.[465]

1. Use of Low Emission Combustion Technology

ETC Texas Pipeline describes units 1A, 2A, and 3A as the same Cooper-Bessemer GMV-10T5 engines but currently operating with low emission control technology.[466] These engines were retrofit in 2007 by Cameron Compression Systems including new power cylinder heads, gas ignitors, a high efficiency turbocharger, and guaranteeing a controlled NOx emission rate of 2 g/hp-hr.[467]

ETC Texas Pipeline assumes a controlled NOx emission rate from LEC retrofits on units 4A and 5A of 1 g/hp-hr and estimates this represents an 81–89% reduction from baseline NOx emission rates that are based on the 2016 emissions inventory.[468] The permitted maximum hourly NOx emission rate of 27.9 lb/hr for these units is significantly higher than the 2016 emissions

[459] Title V Operating Permit P090-R3 for Jal #3 Gas Plant at A3.
[460] *Id.* at A7–A9.
[461] October 2019 Regional Haze Four-Factor Analysis for ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant at 2 and Appendix B.
[462] *Id.* at 2.
[463] Title V Operating Permit P090-R3 for Jal #3 Gas Plant at A7.
[464] *Id.* at A10.
[465] October 2019 Regional Haze Four-Factor Analysis for ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant Appendix B.
[466] *Id.* at 2.
[467] *Id.* at 4 and Appendix A (*see* pdf page 26).
[468] *Id.* at 5.

inventory data used for baseline emissions, especially for unit 5A. The allowable hourly NOx emission rate is equivalent to 11.5 g/hp-hr for these 1,100 hp engines. The source's Title V renewal application provided details on the basis for the uncontrolled NOx emission rate as stack test data, with data provided for all five Cooper-Bessemer GMV-10TF engines. The stack test data for units 4A and 5A are shown in the table below, along with the baseline emissions used in the four-factor analysis (that are based on 2016 emissions inventory calculations):

Table 30. ETC Texas Pipeline Jal No. 3 Gas Plant 2SLB RICE Unit NOx Emission Rates

Unit	Size [hp]	NOx Permit Limit [lb/hr]	NOx Permit Limit [g/hp-hr]	NOx Stack Test Data from Title V Permit Application [g/hp-hr]	NOx Baseline Emissions from August 2016 EI [g/hp-hr]
A4	1,100	27.9	11.5	6.2–6.8	9.4
A5	1,100	27.9	11.5	7.2–8.2	5.1

Assuming a controlled NOx emission rate for LEC of 1 g/hp-hr, emissions reductions range from 84–89% for unit A4 and from 81–88% for units A5. ETC Texas Pipeline assumed 89% control for unit A4 and 81% control for unit A5. If unit A5 operates at a higher emission rate than in 2016—one that is more reflective of the emission rate from the stack testing completed for the source's Title V Renewal Application—then the emissions reductions would be greater than what was assumed in the four-factor analysis.

It's possible that the controlled emission rate with LEC for these specific engines could be even lower that 1 g/hp-hr. For reference, the following additional sources of information regarding NOx emission rates specific to Cooper-Bessemer GMV model engines – both uncontrolled and with LEC technology – are provided here:

- EPA's 2000 RICE Update includes NOx emissions test data for specific engines, including Cooper-Bessemer GMV-10C, 2-stroke, lean-burn, 1,100 hp RICE retrofitted with LEC. Tested at 0.61 g/bhp-hr.[469]

- An evaluation by a technical group for the Pipeline Research Council International looked at three of the most representative make / models of 2-stroke lean burn compressor engines: (1) 2,250 hp Cooper GMVH-10; (2) 2,000 hp Clark TLA-6; and (3) 2,500 hp Cooper GMW-10. According to a technical report by the Ozone Transport Commission (OTC) describing this evaluation, "[t]he evaluation concluded that there were no technology gaps and that each of the three makes/models evaluated were capable of attaining a NOx emissions limitation of 0.5 g/bhp-hr using a combination of improvements and retrofits related to air supply, fuel supply, ignition, electronic controls, and engine monitoring."[470]

[469] EPA 2000 RICE Update at 4-8.
[470] 2012 OTC Report at p. 24.

LEC controls at unit 5A would be even more cost effective if the baseline emission rate is more in line with the stack test data provided in the source's Title V Renewal Application (i.e., reflective of 88% control).

ETC Texas Pipeline states that units 4A and 5A are backup engines that operate, on average, 25-50% of the time each year.[471] The four-factor analysis is based on operating hours from the 2016 emissions inventory of 560 hours for unit 4A and 4,290 hours for unit 5A, or 6% and 50% operation, respectively. Therefore, the cost effectiveness of LEC controls at unit 4A would be more favorable than what is shown in the four-factor analysis for operation between 25-50%. Revising ETC Texas Pipeline's cost effectiveness analyses to address some of these issues, including assuming 1) 88% control of NOx at unit 5A, and 2) unit 4A operating 50% of the year, results in more favorable cost effectiveness of these controls, as shown in the table below.

Table 31. Cost Effectiveness of LEC at Uncontrolled Jal No. 3 Gas Plant Units 4A and 5A to Reduce NO_x Levels to 1 g/hp-hr, Assuming 89% Control (Unit 4A) and 88% Control (Unit 5A) and Unit 4A Operating 50% of the Year, 2019 $

Unit	Size [hp]	Capital Cost of LEC (vendor quote)	Annual O&M Costs (13% of Capital Costs)	Total Annualized Costs of LEC to Reduce NOx to 1 g/hp-hr (88-89% NOx Reduction)	Annual Operating Hours, hr/yr	NOx Removed, tpy	Cost Effectiveness of LEC, $/ton
4A	1,100	$798,355	$103,786	$135,720	4,380	45	$3,042/ton
5A	1,100	$798,355	$103,786	$135,720	4,290	37	$3,624/ton

Note, the cost effectiveness of LEC controls would be more favorable for both units if they were able to meet controlled emission rates below 1 g/hp-hr, which, as discussed earlier, has been demonstrated for other LEC retrofits for similar engines.

2. Use of SCR

ETC Texas Pipeline also evaluated SCR as a control for the two-stroke lean burn engines at Jal No. 3. The company did identify concerns with applicability of SCR to the two-stroke lean burn units including reagent injection control, exhaust temperature requirements, variations in the exhaust NO/NO_2 ratio, and engine oil carryover harming the SCR catalyst.[472] In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by

[471] October 2019 Regional Haze Four-Factor Analysis for ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant at 2.
[472] *Id.* at 4.

reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[473]

Irrespective of the company's concerns with applicability of SCR to the lean burn engines, ETC Texas Pipeline did conduct a cost effectiveness evaluation for SCR at Units 4A and 5A assuming a target NOx emission rate of 1 g/hp-hr.[474] Specifically, the company estimated the cost effectiveness of SCR at Unit 4A, which in its base emissions only operated 560 hours per year, as $28,561/ton, and at Unit 5A, which operated 4290 hours in its base emissions, at $7,517/ton.[475]

ETC Texas Pipeline appears to have used a 2000 NESCAUM Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines to estimate capital costs for SCR.[476] Specifically, the NESCAUM formula which was based on only one case study for a RICE unit to "approximate" SCR capita costs for lean burn RICE is as follows:

$310,000 + ($72.7 x hp)[477]

This NESCAUM equation is twenty years old and is likely based on cost data from the 1990's. SCR has been implemented on numerous source types over the past twenty years, and the much wider-scale implementation and innovation in catalyst design has lowered the cost of SCR.[478] Yet, ETC Texas Pipeline's analysis escalated the capital costs developed with the above equation from the 2000 NESCAUM report by assuming the NESCAUM cost equation was based on 1994 costs and escalating to 2019, using the differences in the Consumer Price Index between 1994 and 2019.[479] EPA's Control Cost Manual cautions against escalating costs more than five years due to the potential for significant inaccuracies in price estimates.[480]
EPA currently has a spreadsheet available to estimate the capital and operating costs for SCR. While the spreadsheet was developed for fossil fueled fired boilers, it can be used as an estimate for SCR at other natural gas-fired sources and, in fact, has been used oil and gas companies for several four-factor analyses submitted to NMED. Unfortunately, ETC Texas Pipeline did not include the necessary information to use the EPA SCR cost spreadsheet to estimate SCR costs for the Units 4A and 5A engines. NMED should ask the company to use the EPA spreadsheet rather than the NESCAUM formula and escalate the cost 25 years to current dollars.

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[473] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[474] October 2019 Regional Haze Four-Factor Analysis for ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant at 2.
[475] *Id.* at Appendix B.
[476] *Id.* at 8. *See also* December 2000 NESCAUM Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines at III-30.
[477] *Id*.
[478] See EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.
[479] October 2019 Regional Haze Four-Factor Analysis for ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant at Appendix B.
[480] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.

In addition, the company's assumed annual operations and maintenance cost, estimated to be 20% of the total capital cost, is arbitrary and unjustified. In particular, ETC Texas Pipeline's annual operations and maintenance costs have no connection to the operating capacity of Units 4A and 5A. As a comparison, in Section XIX.A.2. below, we provide an SCR cost estimate using the EPA cost spreadsheet for the Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[481] For the two units at Roswell Compressor No. 9, that are 4500 hp each and that operate at 11% to 41% of available hours, the operation and maintenance costs to achieve 90% NOx reduction were roughly $26,000/year. See Table 46 in Section XIX.A.2. below.

If we assume that the operation and maintenance expense at Units 4A and 5A are the same as the larger units at Roswell Compressor No. 9 – i.e., $26,000 per year rather than ETC Texas Pipeline's assumed $134,973 per year, the cost effectiveness of SCR at Units 4A and 5A at Jal No. 3 decrease to $10,191/ton at Unit 4 A and $2,459/ton at Unit 5A. Thus, a more appropriate annual operations and maintenance cost make SCR very cost effective particularly at Unit 5A which operates more than Unit 4A.

For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal. NMED should request that ETC Texas Pipeline submit a refined analysis of SCR cost effectiveness using the EPA SCR cost spreadsheet.

B. SO2 Emissions from Thermal Oxidizer

ETC Texas Pipeline also evaluated controls for thermal oxidizer which combust the acid gas stream from its amine units.[482] We address that analysis in Section XXIII of this report.

XII. Davis Gas Processing Denton Gas Plant

The Denton Gas Plant is a natural gas processing plant in which the H2S is removed from the natural gas in an amine unit and then the gas is processed through a cryogenic unit to condense natural gas liquids.[483] The plant is located about 11 miles east of Lovington, New Mexico in Lea County. It is owned/operated by Davis Gas Processing. The plant consists of an amine unit, dehydrator regenerator, four-stroke rich burn RICE units, heaters, and tanks, but SO2 emissions from flaring of acid gases are the primary source of air emissions from the plant.[484] Thus, the four-factor analysis for this facility focused on the amine unit and the acid gas flare (Unit No. 007)Amine unit and flare.[485] Comments on the company's four-factor analysis are provided in Section XXIII further below, in comments on amine units and flaring emissions.

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[481] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 5.
[482] October 2019 Regional Haze Four-Factor Analysis for ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant at 7.
[483] 5/10/2017 Title V Operating Permit No. P079-R3 for Davis Gas Processing Denton Gas Plant at 4.
[484] *Id.* at A6 to A8.
[485] November 2019 Four-Factor Analysis for Denton Gas Plant at 2-1.

XIII. El Paso Natural Gas Company – Washington Ranch Storage Facility

The El Paso Natural Gas Company, LLC. (EPNG) Washington Ranch Storage Facility is located in Eddy County and was identified by NMED as one of the sources contributing to regional haze at Carlsbad Caverns National Park Class I area.[486] NMED has described the facility processes as follows:

> The function of the facility is to compress and inject pipeline quality natural gas into underground storage wells and withdraw the gas for delivery into the pipeline.[487]

According to the permit, the plant includes two 2-stroke lean-burn reciprocating internal combustion engines (RICE), a 4-stroke rich-burn auxiliary engine, a glycol dehydrator and reboiler, a heater, a flare, and a diesel water pump engine.[488] In EPNG's four-factor submittal, the company evaluated air pollution controls for the following emission units:

- Cooper-Bessemer 2SLB RICE 12Q155HC2: Units A-01 and B-02.[489]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[490] The following provides a review of the company's four-factor analyses.

A. Units A-01 and B-02: Cooper-Bessemer 12Q155HC2 2-Stroke Lean-Burn Compressor Engines

Units A-01 and B-02 are 2-stroke lean-burn RICE that were constructed in 1982, each with a capacity of 4,500 hp.[491] The units each have an hourly NOx limit of 27.3 lb/hr and an annual NOx limit of 119.5 tpy.[492]

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[486] November 2019 Regional Haze Four-Factor Analysis for El Paso Natural Gas Company, LLC Washington Ranch Storage Facility at 3.
[487] Title V Operating Permit P064-R3 for Washington Ranch Storage Facility at 3.
[488] *Id.* at 5-6.
[489] November 2019 Regional Haze Four-Factor Analysis for El Paso Natural Gas Company, LLC Washington Ranch Storage Facility at 4.
[490] *Id.* at 4.
[491] Title V Operating Permit P064-R3 for Washington Ranch Storage Facility at 5.
[492] *Id.* at 6.

1. Use of Low Emission Combustion Technology

EPNG describes a "layered approach" strategy for Clean Burn technology applied to the two engines reviewed in its four-factor analysis, A-01 and B-02.[493] Specifically, EPNG states that these units are already equipped with a turbocharger, advanced ignition system, pre-combustion chambers, high pressure fuel injection systems, and an Automatic Balancing Platform.[494] According to EPNG these Clean Burn technologies, based on manufacturer guidance, result in NOx emission rates of 0.5–2.75 g/hp-hr, or 27–82% reduction in NOx emissions.[495] Based on the information provided on the different Clean Burn technologies available for these engines it's possible that there are additional technologies that could be employed to ensure the NOx emission rates are closer to 0.5 g/hp-hr. For example, it's not clear if the pre-combustion chamber installed on units A-01 and B-02 is a "closed loop ePCC," which corresponds to emission rates of 0.5 g/hp-hr.[496] And it's also not clear if the Automatic Balancing Platform is considered "Advanced TER Control" or "Transient Control," the latter of which would result in emission rates around 0.5 g/hp-hr.[497] In EPA's Alternative Control Techniques document for RICE it reports achievable emission levels for retrofit low-emission designs for a Cooper-Bessemer 16Q155HC engine of 1.8 g/hp-hr.[498] And more recently, EPA has described layered combustion as demonstrated control techniques for 2-stroke lean-burn engines, achieving a NOx emission rate of 0.5 g/hp-hr.[499]

Units A-01 and B-02 have an allowable NOx emission rate of 27.3 lb/hr, or 2.75 g/hp-hr for these 4,500 hp units. And the source's Title V Permit Renewal Application specifies that these permit limits are based on the design for the low emission conversion.[500] NMED should require additional LEC retrofit techniques be evaluated in order to assess the cost effectiveness of further reducing NOx emissions from these engines to a level closer to 0.5 g/hp-hr. Reducing emissions to this level would achieve an additional 82% reduction in NOx emissions from these compressor engines. If these engines operate frequently it could be cost effective to update the Clean Burn technology on these engines, resulting in potentially significant NOx emissions

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[493] November 2019 Regional Haze Four-Factor Analysis for El Paso Natural Gas Company, LLC Washington Ranch Storage Facility at 8.

[494] *Id.*

[495] *Id.*

[496] *Id.* Note, Hoerbiger's Layered Approach Strategy for Clean Burn Technologies (Figure 3) illustrates varying prechamber (PCC) technologies, including "ePCC" and "closed loop ePCC." Hoerbinger's website describes this technology as Electronic Pre-Chamber Check (ePCC) Valves, *see* https://www.hoerbiger.com/en-3/pages/102

[497] *Id.*

[498] EPA 1993 Alternative Control Techniques Document for RICE at 5-68.

[499] 2016 EPA Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS (Docket ID No. EPA-HQ-OAR-2015-0500), Appendix A at 5-5, *available at:* https://19january2017snapshot.epa.gov/sites/production/files/2015-11/documents/assessment_of_non-egu_nox_emission_controls_and_appendices_a_b.pdf [hereinafter referred to as "CSAPR TSD for Non-EGU NOx Emissions Controls"].

[500] September 2013 Title V Permit Renewal Application El Paso Natural Gas Company, LLC Washington Ranch Storage Facility Section 6, Page 2.

reductions. At continuous operation these units have the potential to emit 120 tons per year of NOx each; an 82% reduction using layered combustion to meet a 0.5 g/hp-hr NOx emission rate would prevent almost 200 tons per year of NOx emissions from both units, when operating continuously.

2. Use of SCR

EPNG did not evaluate SCR for Units A-01 and B-02 primarily because it claimed that it was not technically feasible for variable load engines of this type.[501] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for these engines, particularly because EPNG has not found LEC to be a cost effective NOx reduction strategy for these units.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[502]

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[503] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[504] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

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[501] November 2019 Regional Haze Four-Factor Analysis for El Paso Natural Gas Company, LLC Washington Ranch Storage Facility at 7.

[502] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.

[503] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.

[504] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

XIV. Enterprise Blanco Compressor C & D

The Blanco C & D Compressor Station is a natural gas compressor station located about one mile northeast of Bloomfield, New Mexico in San Juan County.[505] It is owned/operated by Enterprise Field Services LLC.

The Title V operating permit for the facility indicates that the plant includes several natural gas-fired turbines, flares, and tanks.[506] In Enterprise's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- GE 5221W combustion turbines (Units T-C01 and T-C02)
- GE M5322B combustion turbine (Unit T-D01)[507]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[508] The following provides a review of the company's four-factor analyses. The following provides a review of the company's four-factor analyses.

A. Interest Rate Used in Cost Analyses.

Enterprise used an 8.38% interest rate in the cost analyses for all of the controls evaluated in its 4-factor analyses.[509] This is an unreasonably high interest rate for cost effectiveness analyses. EPA's Control Cost Manual indicates that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[510] The current bank prime rate is 3.25%.[511] The highest the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[512] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. However, in a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[513] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate

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[505] Title V Operating Permit P218-R2M1 for Blanco C&D Compressor Station at 3.
[506] *Id.* at 7.
[507] November 2019 Regional Haze Four-Factor Analysis for Enterprise Blanco C&D Compressor Station at 1-2.
[508] *Id.*
[509] *Id.* at Section 8.0 Supporting Documentation.
[510] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[511] https://www.federalreserve.gov/releases/h15/.
[512] https://fred.stlouisfed.org/series/DPRIME.
[513] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.

(and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. Enterprise's use of an 8.38% interest rate is unreasonably high and overstates the cost effectiveness of pollution controls evaluated in the four-factor analyses.

B. GE Combustion Turbines: Units T-C01 and T-C02 and T-D01

Units T-C01 and T-C02 at the Blanco C&D Compressor Station are each 22,280 hp natural gas-fired turbines that are listed in the Title V permit as constructed before June 1989.[514] The units each have a NOx emissions limit of 80.0 lb/hr and 350.4 tpy.[515] For these units, Enterprise identified water or steam injection as viable combustion controls for NOx but claimed that dry low NOx combustors were not available for retrofit to these types of gas turbines.[516] Unit T-D01 is a GE M5322B combustion turbine of 32,550 hp capacity that is identified in the Title V permit as being constructed before October 1987.[517] Unit T-D01 has NOx limits of 143.3 lb/hr and 628 tpy.[518] For this unit, Enterprise identified water or steam injection or dry low NOx combustors as feasible controls.[519] Enterprise claimed that SCR installation was not possible for any of these gas turbines, due to the size estimates of the SCR.[520] Presumably, Enterprise is claiming issues of retrofit difficulty. There is no question that SCR is technically feasible for natural gas-fired combustion turbines, including those used at compressor stations.

1. Evaluation of Baseline NOx Emissions.

According to the company's cost analysis for water/steam injection, Unit T-C01 has an actual NOx emission rate of 36.92 lb/hr (57.7 ppm), Unit T-C02 has an actual NOx emission rate of 51.56 lb/hr (83.2 ppm), and Unit T-D01 has an actual NOx emission rate of 49.32 lb/hr (65.0 ppm) based on 2016 stack test data.[521] These actual emission rates are much lower than the units' allowable NOx emission rates so, either the 2016 stack test data was not performed while the engines were operating at maximum capacity or the allowable NOx emission rates have been set unreasonably high. In addition, while both Units T-C01 and T-C02 are the same model and same horsepower, one unit's NOx rate (T-C01) is listed by Enterprise as 31% lower than the NOx rate of T-C02. That does not make sense, if such emission rates are reflective of test data at maximum or close to maximum capacity. NMED should present information on the 2016 stack test data so the circumstances of the stack tests can be reviewed. In addition, NMED and Enterprise should review other stack tests for these units to ensure that the actual emission rates can be considered to truly reflect actual emissions over the lifetime of the controls being evaluated. If testing is only done sporadically, such as once every five years, then it is

[514] Title V Operating Permit P218-R2M1 for Blanco C&D Compressor Station at 7.
[515] *Id.* at 8.
[516] November 2019 Regional Haze Four-Factor Analysis for Enterprise Blanco C&D Compressor Station at 2-2 to 2-4.
[517] Title V Operating Permit P218-R2M1 for Blanco C&D Compressor Station at 7.
[518] *Id.* at 8.
[519] November 2019 Regional Haze Four-Factor Analysis for Enterprise Blanco C&D Compressor Station at 2-2 to 2-4.
[520] *Id.* at 2-4.
[521] November 2019 Regional Haze Four-Factor Analysis for Enterprise Blanco C&D Compressor Station at Section 8.0.

questionable that such stack test data truly reflect an accurate projection of emissions expected over the lifetime of the controls being evaluated, especially given that the emission rates are so much lower than the units' allowable pound per hour emission rates. NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on an estimate of emissions expected in 2028.

2. Evaluation of Water Injection and Steam Injection for NOx Control

Enterprise only assumed 15% NOx reduction from water or steam injection.[522] While Enterprise cites to EPA's AP-42 emission factor documentation for the 15% control with water or steam injection, EPA's AP-42 states that such controls can achieve 60% or higher NOx removal.[523] EPA's 1993 Alternative Control Techniques Document for NOx emissions from Stationary Gas Turbines, which EPA's AP-42 documentation cites to, states that NOx rates in the range of 25 to 42 ppmv can be achieved with water or steam injection as gas-fired combustion turbines.[524] If the uncontrolled emissions of Units T-C01, T-C02, and T-D01 are truly in the range of 57.7 to 83.2 ppm as indicated in Enterprise's four-Factor analyses (assuming this is parts per million by volume at 15% oxygen, which NMED should confirm), water injection to meet a NOx rate of 25-42 ppm reflects 27% to 70% NOx removal. NMED must require that Enterprise evaluate water or steam injection for these units reflective of the NOx rates that have historically been achieved with water or steam injection.

With respect to the life assumed of water or steam injection, Enterprise only assumed a 15-year life of these controls.[525] Enterprise did not provide any justification for assuming such a short life of water or steam injection. As discussed in NPCA's March 2020 report, the life of water or steam injection should be the life of the combustion turbines. In NPCA's March 2020 report, we assumed a 25-year life of water or steam injection.[526]

In terms of Enterprise's costs for water injection or steam injection, the company's capital costs seem very high for the size turbines, based on a comparison to the 1999 Department of Energy report entitled "Cost Analyses of NOx Control Alternatives for Stationary Gas Turbines," which is cited in several EPA and State documents on the costs of NOx controls at gas turbines.[527] In that 1999 DOE report, the costs of water or steam injection for a gas turbine that is larger than Units T-C01 and T-C02 and slightly smaller than T-D01, a GE LM2500 turbine which is of 22.7 megawatt capacity or about 30,400 hp, the capital cost in 1999 dollars of water injection was

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[522] *Id.*
[523] EPA, AP-42 Emission Factor Documentation, at 3.1-6.
[524] *See* EPA. Alternative Control Techniques Document – NOx Emissions form Stationary Gas Turbines, EPA-453/R-93-007, January 1993, at 2-5 [hereinafter EPA 1993 Gas Turbine ACT].
[525] November 2019 Regional Haze Four-Factor Analysis for Blanco C&D Compressor Station at 6-1.
[526] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 64.
[527] Bill Major, ONSITE SYCOM Energy Corporation, and Bill Powers, Powers Engineering, Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines, prepared for U.S. Department of Energy, November 5, 1999, available at: https://www.energy.gov/sites/prod/files/2013/11/f4/gas_turbines_nox_cost_analysis.pdf [hereinafter "1999 DOE Report"].

estimated to be $1,083,175.[528] Although EPA's Control Cost Manual advises against escalating costs more than five years because it can lead to inaccuracies in price estimation,[529] just using the Chemical Engineering Plant Cost Indices between 1999 and 2018, the DOE's 1999 costs of water injection for a larger GE LM2500 gas turbine would increase to $1.67 million.[530] Using a different cost index specific to oil refineries, the Nelson-Farrar index, the 1999 costs of water injection increase from $1.0 million to $1.88 million as of 2016 (the most recent annual Nelson-Farrer cost index found online).[531] Yet, Enterprise's capital cost estimate for water injection at T-C01 and T-C02 was $6.1 million, more than three times the escalated capital costs from the 1999 DOE report based on either the CEPCI index or the Nelson-Farrar index. Thus, Enterprise's capital cost estimate of water injection for a smaller capacity gas turbine at these units seem very high, and its capital costs for steam injection are $2 million higher than its costs for water injection. Further, the inspection and operating costs of water injection, which Enterprise stated would be $1,238,327 per year,[532] are not explained or documented and seem unreasonably high. NMED must request more details and support for these cost estimates of water injection and of steam injection at these units.

We addressed just some of these issues to revise Enterprise's cost effectiveness analyses to reflect 1) a 4.7% interest rate (instead of 8.38%), 2) a 25-year life of water or steam injection (instead of an assumed 15-year life), 3) a controlled NOx rate with water or steam injection of 25 ppmvd at 15% O_2. With the revisions listed in items 1 through 3 above, Enterprise's cost effectiveness of water or steam injection reduced from approximately $57,000 to $110,000/ton of NOx removed to $14,000 to $51,000/ton, and it is important to note that no changes were made to Enterprise's apparently inflated capital and operating costs of water or steam injection.

In its identification of energy and non-air quality environmental impacts of compliance, Enterprise did not list water use as an adverse environmental impact, but it is an issue to be concerned with for water injection.[533] That is why dry low NOx combustion, if available (which Enterprise claims is not available for the Units T-C01 and T-C02 turbine models) or selective catalytic reduction (SCR) are more preferable choices for NOx control from gas-fired turbines in New Mexico.

3. Evaluation of Dry Low NOx Combustion at Unit T-D01

Enterprise did evaluate dry low NOx combustors for the GE M5322B unit (Unit T-D01), but claimed that dry low NOx combustors could only achieve a NOx rate of 35 ppmv at this unit, or

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[528] *Id.*, Appendix A at A-4.
[529] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.
[530] Based on multiplying the 1999 cost estimate for water injection from the 1999 DOE report by the ratio of the CEPCI indices for 2018 to 1999 (603.1/390.6).
[531] Based on multiplying the 1999 cost estimate for water injection from the 1999 DOE report by the ratio of Nelson-Farrar indices for 2016 to 1999 (2598.7/1497.2).
[532] November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant at 8-2 to 8-3.
[533] *See* March 6, 2020 NPCA Oil and Gas Four-Factor Report at 67-68.

a NOx reduction efficiency of 46%. This is a high NOx rate and a low NOx removal efficiency to assume with dry low NOx combustors. As discussed in NPCA's March 2020 Oil and Gas Four-Factor Report, such controls can achieve NOx removal efficiencies of 80-95% with typical NOx emission rates in the range of 9-15 ppm.[534] In a 1999 Department of Energy Report on the costs of NOx controls for gas combustion turbines, the highest NOx emission rate evaluated with dry low NOx combustors was 25 ppm.[535] Thus, Enterprise's cost effectiveness analysis for dry low NOx combustors assumed an unreasonable low level of NOx reduction with this control.

In terms of the life of dry low NOx combustion controls in the cost effectiveness analyses, Enterprise's analysis assumed a 20-year life. For the reasons described above on the evaluation of dry low NOx combustors at the gas turbines at the Chaco Gas Plant, a 25-year life is a more appropriate assumption for the cost effectiveness analysis.[536]

In the table below, Enterprise's cost effectiveness analyses of dry low NOx combustors were revised to take into account a longer lifetime of controls and a lower 4.7% interest rate. In addition, two lower NOx rates were evaluated: 25 ppm and 15 ppm.

Table 32. Revised Cost Effectiveness of Dry Low NOx Combustors at Unit T-D01 of the Blanco C&D Compressor Station, to Reflect a 4.7% Interest Rate and a 25 Year Life[537]

NOx Emission Rate Evaluated, ppm	NOx Removal Efficiency Evaluated	Annual Cost of Dry Low NOx Combustors (at 4.7% interest and 25 Year Life)	NOx Emissions Reduced, tpy	Cost Effectiveness
35[538]	46%	$609,798	91.04	$6,694/ton
25	62%	$609,798	121.46	$5,021/ton
15	77%	$609,798	151.82	$4,017/ton

Dry low NOx combustors at Unit T-D01 are much more cost effective than water or steam injection and, based on historical assumed NOx emission rates with these controls which range between 15 to 25 ppm (or even as low as 9 ppm), such controls should be able to reduce NOx emissions at Unit T-D01 by 62 to 77% or maybe more.

[534] March 2020 NPCA Oil and Gas Four-Factor Report at 69.
[535] *Id. See also* Bill Major, ONSITE SYCOM Energy Corporation, and Bill Powers, Powers Engineering, Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines, prepared for U.S. Department of Energy, November 5, 1999, 2-10, available at: https://www.energy.gov/sites/prod/files/2013/11/f4/gas_turbines_nox_cost_analysis.pdf.
[536] *See also* NPCA March 2020 Oil and Gas Four-Factor Report at 69-70.
[537] The company's capital and operational and maintenance costs were not revised for this analysis. Only the interest rate was reduced from 8.38% to 4.7% and the life of controls was revised from 20 to 25 years.
[538] This in the NOx rate evaluated by Enterprise for dry low NOx combustors at Unit T-D01.

4. Evaluation of SCR for the Gas Turbines at Blanco C&D Compressor Station

Enterprise did not evaluate SCR for the gas turbines at the Blanco C&D Compressor Station, stating that it was "not possible to install these units at the Blanco facility" due to "the amount of buffer space needed to maintain accessibility to equipment and to avoid compromising worker safety."[539] While the facility and gas turbines may not have been originally designed to have space to accommodate SCR, that is typically the case with most SCR retrofits. As such, there have been numerous SCR retrofits installations at various industrial facilities that have had to overcome space constraints. For example, for many large coal-fired power plants, SCR reactors have been elevated above the air preheaters. Indeed, a report about SCR retrofits at GE LM2500 turbines at Chevron's Eastridge Cogeneration plant in California showed that some significant changes to the facility had to be made to accommodate SCR, including cutting the duct between economizers and moving the stack and one economizer onto new foundations to make way for the SCR reactor.[540] Thus, before NMED accepts a very brief claim of retrofit difficulty of SCR at any emissions unit being evaluated for reasonable progress controls, it is imperative that NMED ask Enterprise for a site plan and photos that shows whatever space constraints are being claimed. Moreover, NMED must ask Enterprise to consult with SCR vendors for options for SCR installation at the gas turbines of the Blanco C&D Compressor Station.

If any of the combustion turbines are in close proximity to another turbine, that provides opportunities for a shared SCR reactor which could help with retrofit space issues as well as with costs. NMED must require all possibilities for SCR installation be evaluated and documented by Enterprise. The state must not simply discount this highly effective NOx control based on a claim of some retrofit difficulty.

In terms of the costs of SCR control, NPCA's March 2020 Oil and Gas Four-Factor Report showed the cost effectiveness in 1999 dollars for SCR achieving about 90% NOx reductions would range from $2000/ton to $3400/ton for a 5 MW combustion turbine (~6800 hp engine) depending on the operating capacity factor, and costs decrease for larger turbines like Units 17 and 19 which are approximately 19500 hp engines.[541] For much larger combustion turbines of 75 MW generating capacity (~100,500 hp), cost effectiveness of SCR was significantly lower in the range of $560-$850/ton depending on operating capacity factor.[542]

To get an idea of the costs for SCR at Units T-C01, T-C02, and T-D01 in current dollars, one can use EPA's SCR cost spreadsheet made available as part of EPA's Control Cost Manual. It is difficult to estimate an actual cost effectiveness because it is not clear what the 2016 actual annual fuel throughput was at each unit, which is necessary for estimating annual operations and maintenance costs for SCR. However, a 2017 Title V Permit Application for Blanco C & D

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[539] November 2019 Regional Haze Four-Factor Analysis for Enterprise Blanco C&D Compressor Station at 2-4.
[540] *See* Seebold, James et al., Gas Turbine NOx Reduction Retrofit, , available at https://www.onepetro.org/conference-paper/SPE-66501-MS.
[541] *See* NPCA March 2020 Oil and Gas Four-Factor Report at 75.
[542] *Id.*

compressor stations does have information to enable an estimate of the capital cost of SCR. A review of the EPA SCR cost spreadsheet shows that the capital cost of SCR is based primarily on two factors: maximum hourly heat input to the unit in MMBtu/hr and the site elevation.[543] A 2017 Title V Permit Application for Blanco C&D compressor stations has the maximum hourly heat input to each unit as well as other data, although some of the other data is not legible in the copy of the document on NMED's Emissions Analysis Tool website.[544] Specifically, the hourly heat input to Units T-C01 and T-C02 is identified as 283 MMBtu/hr and the hourly heat input to Unit T-D01 appears to be 311.18 MMBtu/hr.[545]
The site elevation is listed as 5605 feet.[546]

Enterprise's claimed baseline NOx emission rates of 57.2 ppm, 87.3ppm, and 65.0 ppm for Units T-C01, T-C02, and T-C03 were utilized and assumed to be reflective of ppm by dry volume at 15% oxygen. As previously discussed, NMED should ensure that this 2016 test data reflects operations at maximum operating capacity and ensure that these emission rates are a reasonable projection of NOx emissions as of 2028. The company's actual NOx rates were converted to lb/MMBtu emission rates using a conversion formula from EPA's 1993 Alternative Control Techniques Document for Stationary Gas Turbines.[547] Enterprise's ppm NOx baseline rates thus were converted to 0.231 lb/MMBtu for Unit T-C01, 0.334 lb/MMBtu for Unit T-C02, and 0.341 lb/MMBtu for Unit T-D01. With this data, unit-specific information was input into EPA's SCR cost spreadsheet to estimate cost effectiveness of SCR at these units. For Units T-C01 and T-C01, the average exhaust gas temperature of the bypass stacks of 625 degrees Fahrenheit was used and for Unit T-D01 the exhaust gas temperature of 904 degrees Fahrenheit was used.[548] Two different SCR control levels were assumed: a 15 ppmvd NOx rate, which reflects 74% to 82% NOx removal at the Blanco C&D combustion turbines, and a 90% control efficiency from current uncontrolled actual NOx rates at each turbine. With Enterprise's 2016 actual annual NOx emissions and its reported ppm NOx emissions and the reported heat value of the fuel, actual annual gas consumption rates were estimated for each unit for input into the SCR cost spreadsheet. Capital costs were annualized applying a cost recovery factor using a 4.7% interest rate, and a 25-year life which EPA has identified as typical for SCR systems used at industrial boilers.[549] One reagent type was evaluated: 29% aqueous ammonia. The results of these analyses are provided in the table below.

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[543] *See* equations in "Cost Estimate" tab, cell B19 (Total Capital Investment), which in turn points to cells G19 and H19, which in turn are based on "Data Inputs" tab cells C10 and C24.
[544] June 27, 2017 Application for Significant Modification, Title V Operating Permit P218-R2, Enterprise Field Services LLC – Blanco C&D Compressor Station, at pdf pages 34-35.
[545] *Id.*
[546] *Id.* at 35. Note the site elevation for Units T C-01 and T-C01 is not legible, but it is assumed that each C and D compressor station are at the same elevation.
[547] *See* EPA, Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines, EPA-453/R-93-007, January 1993, Appendix A which has conversion equations for natural gas-fired combustion turbines.
[548] *Id.* at pdf page 34-35.
[549] *See* EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80.

Table 33. Cost Effectiveness of SCR at Blanco C&D Compressor Stations Units T-C01, T-C02, and T-D01 Combustion Turbines, Using EPA's SCR Cost Calculation Spreadsheet for Boilers (2018 $)

Unit	Assumed NOx Removal Efficiency with SCR	Capital Cost SCR	Annual Operational and Maintenance Cost	Total Annualized Costs	NOx Reduced, tpy	Cost Effectiveness
T-C01	74.0%	$7,536,749	$155,039	$676,647	119	$5,693
T-C01	90.0%	$7,536,749	$161,977	$683,585	144	$4,731
T-C02	82.0%	$7,536,749	$160,398	$682,006	180	$3,787
T-C02	90.0%	$7,536,749	$164,425	$686,034	198	$3,472
T-D01	77.0%	$8,016,420	$159,735	$714,374	153	$4,684
T-D01	90.0%	$8,016,420	$166,270	$720,909	178	$4,044

The cost estimates of SCR based on EPA's boiler SCR cost spreadsheet project costs for SCR that are significantly lower than the other NOx control evaluated by Enterprise – water or steam injection or dry low NOx combustion for Unit T-D01, for which capital costs were projected to range from $6.6 to $8.2 million.[550] Given that SCR can achieve much higher levels of control at much lower costs than water or steam injection, NMED must require Enterprise to more fully evaluate the ability to install SCR at Unit 17 and/or 18 . Ninety percent control should be readily achievable with SCR at these units to meet a NOx emission rate of 5 to 8 ppmv (0.0231 to 0.0334 lb/MMBtu). Before allowing Enterprise to dismiss SCR due to claims that it is not feasible to locate one or more SCR reactors at Units T-C01, T-C02, and T-D01, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at the units, including any options for shared SCR reactors between Units T-C01 and T-C02. SCR can be a very effective method for reducing NOx emissions from the Blanco C & D compressor station gas turbines and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for the Blanco C & D Compressor Station.

XV. Harvest Pipeline – San Juan Gas Plant

The Harvest Pipeline Company San Juan Basin Gas Plant is a facility that extracts and processes natural gas liquids and residue gas products from field gas via a cryogenic process. It is located about 2 miles northeast of Bloomfield, New Mexico. The facility consists of several combustion turbines, a diesel generator, heaters, a thermal oxidizer, and a flare.[551] It is located adjacent to the Blanco Compressor Stations of EPNG (Blanco C&D) and El Paso Field Services (Blanco A).[552]

[550] November 2019 Regional Haze Four-Factor Analysis for Enterprise Blanco C&D Compressor Station at 8-1 to 8-3.
[551] *Id.* at A6.
[552] Title V Permit No. P124-R3 for San Juan Basin Gas Plant, at A3.

In fact, the three Blanco Compressor Stations and the San Juan Gas Plant are all considered one source under the New Source Review program by NMED.[553]

In Harvest Pipeline's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Rolls Royce 155 Natural Gas Turbines (Units 1-4)
- Solar Centaur T4501 Natural Gas Turbines (Units 4-7).[554]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[555] The following provides a review of the company's four-factor analyses.

A. Interest Rate Used in Cost Analyses.

Harvest Pipeline used a 5.5% interest rate in the cost analyses for all of the controls evaluated in its 4-factor analyses.[556] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. This is the same interest rate that EPA has used in its cost spreadsheet for SCR, but EPA also states that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[557] The current bank prime rate is 3.25%.[558] The highest the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[559] In a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[560] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. For these reasons, in the cost effectiveness calculations provided herein, a 4.7% interest rate is used rather than a 5.5% interest rate.

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[553] 10/10/2018 Statement of Basis for San Juan Gas Plant, Permit Nos. 0613-M8 and P124-R3 at 2.
[554] November 2019 Regional Haze Four-Factor Analysis for Harvest San Juan Gas Plant at 1-2.
[555] *Id.*
[556] *Id.* at Appendix B Cost Analysis Calculations.
[557] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[558] https://www.federalreserve.gov/releases/h15/.
[559] https://fred.stlouisfed.org/series/DPRIME.
[560] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.

B. Rolls-Royce 155 Combustion Turbines: Units 1-4 at San Juan Gas Plant

Units 1-3 of the San Juan Gas Plant are Rolls-Royce Natural Gas Turbines that were manufactured in the mid-1980's.[561] The turbines have a permitted capacity of 15000 hp each, although they have a manufacture rated capacity of 23,800 hp.[562] Unit 4 is a rotating spare for Units 1 – 3, which operates only when Units 1, 2, or 3 are down for repair.[563] The turbines have catalytic oxidation for carbon monoxide and volatile organic compound (VOC) control.[564] The units are each subject to a NOx limit of 56.3 lb/hr and 246.4 tpy.[565] The units are also subject to a NOx limit of 150 ppmv at 15% O_2 pursuant to 40 C.F.R. Part 60, Subpart GG.[566]

For these units, Harvest Pipeline did not evaluate any additional NOx pollution controls. The company stated that it contacted Siemens, the company that currently owns the Rolls-Royce Avon gas turbine and compressor business, and that Siemens stated that neither dry low NOx combustion nor water or steam injection was an available control option for retrofit to the mid-1980's era Rolls-Royce turbines at the San Juan Gas Plant.[567] Siemens indicated that SCR is available for the turbine model, yet Harvest Pipeline did not evaluate SCR. The following provides comments on SCR applicability for the Rolls-Royce turbines.

1. Evaluation of SCR at the Rolls-Royce Turbines (Units 1-4)

Although, according to the four-factor analysis for the San Juan Gas Plant, Siemens claimed that SCR was an available technology for the Rolls-Royce turbines, Harvest Pipeline did not evaluate SCR technology for the turbines. The company claimed that the high exhaust temperature of the turbines (1250 degrees Fahrenheit according to the four-factor analysis) and concerns about space and power usage made SCR not feasible for the Rolls-Royce turbines.[568] SCR should not have been so readily discounted as a pollution control for the Rolls-Royce turbines. With respect to space limitations, as discussed in Section I.B.3. above, most SCR retrofits have space limitations, because the facility was not likely designed to have space to accommodate SCR. There have been numerous SCR retrofits installations at various industrial facilities that have had to overcome space constraints. For example, for many large coal-fired power plants, SCR reactors have been elevated above the air preheaters. Indeed, a report about SCR retrofits at GE LM2500 turbines at Chevron's Eastridge Cogeneration plant in California showed that some significant changes to the facility had to be made to accommodate SCR, including cutting the duct between economizers and moving the stack and one economizer onto new

[561] Title V Permit No. P124-R3 for San Juan Basin Gas Plant, at A6.
[562] *Id.*
[563] November 2019 Regional Haze Four-Factor Analysis for Harvest San Juan Gas Plant at 1-3.
[564] *Id.* at A7.
[565] *Id.*
[566] *Id.* at A8.
[567] *Id.* at 2-3 to 2-4.
[568] *Id.* at 2-5 to 2-6.

foundations to make way for the SCR reactor.[569] Thus, before NMED accepts a very brief claim of retrofit difficulty of SCR at any emissions unit being evaluated for reasonable progress controls, it is imperative that NMED ask Harvest Pipeline for a site plan and photos that shows whatever space constraints are being claimed, and that NMED ask the company to consult with SCR vendors for options for SCR installation at the gas turbines.

Depending on the proximity of the gas turbines, it is possible that one SCR reactor could be used by more than one combustion turbine. This would reduce costs and potentially be easier to install at the site. NMED should require all possibilities for SCR installation be evaluated and documented by Enterprise. The state must not simply discount this highly effective NOx control based on a claim of some retrofit difficulty.

Regarding the company's stated exhaust temperature of 1,271 degrees Fahrenheit, NMED should determine if this is the sustained temperature of the gas turbines or the maximum temperature of the exhaust expected from the turbines. It must be noted that this exhaust temperature of 1,271 degrees Fahrenheit claimed in the four-factor analysis is much higher than the exhaust temperatures of the units cited in the February 2017 Title V permit application for the San Juan Gas Plant. Specifically, the 2017 permit application listed the exhaust temperature of Units 2 and 3 of 370 degrees Fahrenheit and the Unit 1, Unit 2 bypass, and Unit 3 bypass exhaust temperature as 750 degrees Fahrenheit.[570] Thus, NMED must ensure the accuracy of any stated claims about SCR being infeasible due to exhaust gas temperatures before allowing SCR to be eliminated as a control option. In addition, there are options for dealing with high exhaust temperature of simple cycle turbines to enable the use of SCR. The Buckingham Compressor Station which is proposed to be constructed in Virginia would be equipped with Solar turbines with SoLoNOx, SCR, and cooling air skids.[571] Essentially, the cooling air skids provide for the injection of tempering air at the turbine discharge (upstream of the SCR) to cool the exhaust temperature to the optimal temperature of the SCR catalyst.[572]

Further, if the Rolls-Royce turbines truly have exhaust temperatures of 1,271 degrees Fahrenheit, that is another reason why NMED should investigate routing more than one combustion turbine exhaust to a common SCR. The routing of turbine exhausts from multiple turbines to one SCR reactor will allow for some cooling of the exhaust before it enters the SCR. As previously discussed, SRP is planning to route the flue gas from one boiler at the Coronado

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[569] *See* Seebold, James et al., Gas Turbine NOx Reduction Retrofit, , available at https://www.onepetro.org/conference-paper/SPE-66501-MS.

[570] February 2017, New Mexico Application to Renew Permit P-124-R2, San Juan Gas Plant, Submitted by Conoco Phillips Company, at pdf page 39 (San Juan Basin Gas Plant, Turbine Exhaust Emissions Calculations).

[571] *See* May 25, 2018 Permit Application for Altlantic Coast Pipeline LLC, Buckingham Compressor Station, at pdf page 129 (Design Summary), which is available for download at https://www.deq.virginia.gov/Programs/Air/BuckinghamCompressorStationAirPermit/BuckinghamCompressorStationArchivedDocuments.aspx.

[572] *See,* e.g., Buzanowski, Mark A. and Sean P. McMenamin, Peerless Mfg. Co., Automated Exhaust Temperature Control for Simple Cycle Power Plants, available at https://www.powermag.com/automated-exhaust-temperature-control-for-simple-cycle-power-plants/. *See also* Mitsubishi Hitachi Power Systems (MHPS) webpage on SCR systems for simple cycle turbines at https://amer.mhps.com/scr-for-simple-cycle-gas-turbines.html.

Generating Station in Arizona to an existing SCR reactor that had previously been constructed at the coal-fired power plant Coronado Unit 2. Such an approach seems like it could be a viable, more cost effective, control option for co-located combustion turbines at compressor stations.

To estimate the cost effectiveness of SCR for the Rolls-Royce combustion turbines, EPA's SCR cost spreadsheet was used along with the turbine operational data presented in the company's February 2017 Title V Permit Application.[573] Because Harvest Pipeline did not evaluate any emissions controls for the Rolls-Royce units, there was no information in the four-factor analysis on actual emissions and/or actual operating hours for the units. Thus, this SCR cost effectiveness analysis had to be based on an allowable emissions baseline. The uncontrolled NOx rate for input into the spreadsheet was estimated by dividing the allowable hourly emission rate of 56.30 by the hourly fuel consumption of the turbines of 123.2 MMBtu/hr,[574] for an uncontrolled NOx rate of 0.457 lb/MMBtu. Consistent with other SCR analyses presented herein and in NPCA's March 2020 Oil and Gas Four-Factor Report, it was assumed that SCR could achieve a NOx emission rate of 15 ppmv at 15% O_2,[575] which converts to 0.06 lb/MMBtu. That NOx rate reflects an 87% reduction across the SCR system from the lb/MMBtu allowable NOx emission rate. To reflect a lower capacity factor than potential to emit, an analysis was also done assuming the unit operated at 70% of maximum annual fuel throughput. Consistent with all other SCR cost analyses provided herein, a 25-year life of SCR and a 4.7% interest rate was used. The results of this cost effectiveness analysis are provided in the table below.

Table 34. Cost Effectiveness of SCR to Achieve ~87% NOx Reduction (15 ppmv at 15% O_2) at Unit 1, 2, and 3 of the San Juan Gas Plant, Assuming a 25-Year Life of SCR and a 4.7% Interest Rate

Annual Capacity Factor	Capital Cost of SCR	Annual Operational and Maintenance Costs of SCR	Annualized Cost of SCR	NOx Emission Reductions, tpy	Cost Effectiveness of SCR
100%	$4,388,725	$98,826	$403,662	214	$1,884/ton
70%	$4,388,725	$79,310	$387,146	150	$2,562/ton

Harvest Pipeline also indicated that the electricity currently available at the San Juan facility is sufficient to power SCR systems at the Rolls-Royce units, and stated that "[i]nstallation of [SCR] will require the facility to expand its current power generation."[576] Based on electricity calculations of EPA's SCR cost spreadsheet, if SCR systems were operated for each unit and each unit was operated at 100% of maximum capacity, the electricity needs would be 71.91 kW per hour per unit for an hourly demand need of 0.216 MW. NMED should ask Harvest Pipeline

[573] February 2017, New Mexico Application to Renew Permit P-124-R2, San Juan Gas Plant, Submitted by Conoco Phillips Company, at pdf page 39 (San Juan Basin Gas Plant, Turbine Exhaust Emissions Calculations).
[574] *Id.*
[575] *See* March 2020 NPCA Oil and Gas Four-Factor Report at 75.
[576] November 2019 Regional Haze Four-Factor Analysis for Harvest San Juan Gas Plant at 2-6.

for more information on its current levels of power generation and/or power supply and to estimate what would be necessary to increase the power generation at the site or to the site to accommodate SCR systems. If one SCR reactor could be shared between the three combustion turbines, that could not only reduce the cost of SCR and allow for a less complicated retrofit, but it could also reduce the energy needs of SCR.

Thus, NMED must not allow Harvest Pipeline to discount SCR for the Rolls-Royce units. It is a highly effective NOx control that the turbine manufacturer (Siemens) states is an available retrofit for the existing turbines. NMED must require a thorough evaluation of SCR to reduce NOx emissions from the Rolls-Royce turbines.

C. Solar Centaur T4501 Natural Gas Turbines (Units 4-7)

Units 4-7 of the San Juan Gas Plant are Solar Centaur turbines model T4501 with a permitted capacity of 3735 hp that were each manufactured in 1986.[577] The units each have NOx limits of 15.9 lb/hr and 69.8 tpy.[578] The units are also each subject to a NOx limit of 150 ppmv at 15% O_2 pursuant to 40 C.F.R. Part 60, Subpart GG.

Harvest Pipeline evaluated the following pollution controls for these units:

- SoLoNOx Combustion Technology
- SCR.

The following provides comments on Harvest Pipeline's analyses of these controls.

1. Evaluation of SoLoNOx for Units 4-7 at San Juan Gas Plant

Harvest Pipeline states that SoLoNOx is available for the existing Solar Centaur combustion turbines at Units 4-7, but it would require the units to be uprated to model Centaur T4701 to support the SoLoNOx technology.[579] Harvest Pipeline states that such controls could reduce NOx to 25 ppm, a reduction of 65-75% from 2016 hourly NOx rates.[580]
In terms of the life of SoLoNOx controls in the cost effectiveness analyses, Harvest Pipeline's analysis assumed a 20-year life. For the reasons described above on the evaluation of dry low NOx combustors at the gas turbines at the Chaco Gas Plant, a 25-year life is a more appropriate assumption for the cost effectiveness analysis.[581] In the table below, Harvest Pipeline's cost effectiveness analyses of SoLoNOx were revised to take into account a longer lifetime of controls and a lower 4.7% interest rate.

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[577] Title V Permit No. P124-R3 for San Juan Basin Gas Plant, at A6.
[578] *Id.* at A7.
[579] November 2019 Regional Haze Four-Factor Analysis for Harvest San Juan Gas Plant at 2-3.
[580] *Id.*
[581] *See also* NPCA March 2020 Oil and Gas Four-Factor Report at 69-70.

Table 35. Revised Cost Effectiveness of SoLoNOx at Units 4-7 of the Harvest Pipeline San Juan Gas Plant, to Reflect a 4.7% Interest Rate and a 25-Year Life

Unit	Harvest Pipeline's Total Annual Costs of SoLoNOx (at 5.5% Interest and 20-Year Life)	Harvest Pipeline's Cost Effectiveness at 5.5% Interest and 20 Year Life	Revised Total Annual Costs of SoLoNOx	Revised Cost Effectiveness at 4.7% Interest and 25 Year Life
4	$69,637	$1,952/ton	$61,274	$1,717/ton
5	$69,637	$2,412/ton	$61,274	$2,122/ton
6	$69,637	$1,894/ton	$61,274	$1,667/ton
7	$69,637	$1,500/ton	$61,274	$1,319/ton

Thus, the cost effectiveness of SoLoNOx at the Units 4-7 Solar Centaur Combustion Turbines should be in the range of $1,319/ton to $2,122/ton assuming a more appropriate 25-year life at lower interest rate. These controls should be considered quite cost effective by NMED.

2. Evaluation of SCR for Units 4-7 of the San Juan Gas Plant.

Harvest Pipeline evaluated SCR as a technically feasible control option for the Units 4-7 Solar Centaur gas combustion turbines, using EPA's SCR cost spreadsheet made available with EPA's Control Cost Manual.[582] However, Harvest Pipeline only assumed a 25 ppm NOx rate could be met with SCR, which only reflects 65% to 76% NOx reduction efficiency with SCRAs presented NPCA's Oil and Gas Four-Factor Report, NESCAUM assumed 90% control with SCR in its 2000 Status Report to control small gas turbines down to 15 ppmv.[583] SCR at the San Juan Gas Plant Units 4-7 should be able to at least achieve a 15 ppmv NOx limit, which reflects 79% to 85% control at each unit.

Harvest Pipeline presented cost effectiveness data for SCR at Units 4-7, but the costs appear to be significantly inflated. The company assumed a $4,000,000 capital cost of SCR that it purportedly obtained from the manufacturer, which is Solar Turbines.[584] It is not clear that Solar Turbines is a vendor for SCR systems. The company also apparently used the EPA cost spreadsheet for the direct annual costs including operating and maintenance costs.[585] Yet, when the inputs used by Harvest Pipeline for each unit are independently input in the EPA SCR cost spreadsheet, the annual operation and maintenance costs are shown to be much lower than assumed by Harvest Pipeline, and the capital cost of SCR is shown to be much lower than $4,000,000 per unit. For example, when one enters into the EPA spreadsheet the same

[582] November 2019 Regional Haze Four-Factor Analysis for San Juan Gas Plant, Appendix C.
[583] NPCA March 2020 Oil and Gas Four-Factor Report at 74-75. *See also* NESCAUM, December 2000, Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, Technologies & Cost Effectiveness at III-21 through III-24 and at III-40 (see referenced 11, 16, 9, 14, and 15), available at http://www.nescaum.org/documents/nox-2000.pdf/view.
[584] November 2019 Regional Haze Four-Factor Analysis for San Juan Gas Plant at 3-2.
[585] *Id.*

information in the data input page for Unit 4 provided in the San Juan Gas Plant Four-Factor Report, the resulting calculation of operations and maintenance costs are $10,703 per year plus $2,718 in administrative charges for a total of $13,421 per year, whereas Harvest Pipeline assumed annual operating and mainatenance costs of $122,869 per year, costs that are nine times higher than calculated with EPA's cost spreadsheet. In addition, the EPA SCR cost spreadsheet calculates the capital cost of SCR at $1.5 million for the unit rather than Harvest Pipeline's claimed $4 million cost, a value that is 2.7 times what the EPA SCR cost spreadsheet calculated.

In the table below, we recalculated cost effectiveness of SCR at Units 4-7 of the San Juan Gas Plant. For this analysis, we used EPA's SCR cost spreadsheet with the same inputs as identified in Harvest Pipeline's Four Factor report.[586] However, for the controlled level of NOx, an emission rate of 15 ppmv was assumed to be met (reflective of 0.10 lb/MMBtu and NOx removal efficiencies in the range of 79% to 85%. For the reasons previously described in this report, an interest rate of 4.7% and a 25-year life of SCR were assumed. The table below presents the results of this analysis.

Table 36. Cost Effectiveness of SCR at San Juan Gas Plant Units 4, 5, 6 and 7 Combustion Turbines to Meet 15 ppmv NOx Rate, Using EPA's SCR Cost Calculation Spreadsheet for Boilers (2018 $)

Unit	Assumed NOx Removal Efficiency with SCR	Capital Cost SCR	Annual Operational and Maintenance Cost	Total Annualized Costs	NOx Reduced, tpy	Cost Effectiveness
4	82%	$1,501,589	$20,793	$126,820	41	$3,059/ton
5	79%	$1,495,807	$21,342	$126,972	44	$2,869/ton
6	82%	$1,465,046	$21,012	$124,523	44	$2,839/ton
7	85%	$1,475,477	$22,001	$126,230	52	$2,405/ton

The above table shows that SCR, based on EPA's cost algorithms, can be cost effective at Units 4, 5, 6 and of the San Juan Gas Plant.
Moreover, SCR combined with SoLoNOx, which is commonly required to meet BACT for gas turbines, could reduce NOx by 97% or more. As discussed in Section I.C.2 of this report, this combination of NOx controls has been permitted for the Buckingham Compressor Station to achieve a NOx emission rates of 3.75 ppmv @ 15% oxygen.[587] However, emission rates with SoLoNOx and SCR at gas-fired combustion turbines could be even lower, as BACT or LAER for

[586] *Id.* in Appendix B, pdf pages 27, 31, 35, and 39 of the report.
[587] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.

such turbines operated for power generation are generally set at 2 to 2.5 ppmv at 15% oxygen.[588] NMED should require Harvest Pipeline to evaluate the cost effectiveness of the combination of SoLoNOx and SCR to achieve the greatest level of NOx reduction.

XVI. Oxy USA WTP -Indian Basin Gas Plant

The Oxy USA WTP (Oxy) Indian Basin Gas Plant is a gas sweetening plan (removing hydrogen sulfide and CO_2 from raw natural gas to make commercial natural gas) and also extracts natural gas products (propane and butane) from natural gas.[589] The facility is located 15 miles west of Carlsbad, New Mexico in Eddy County.[590] The emission units at the plant include an amine unit, heaters, turbine generators and turbine compressors, boilers, and flares.[591]

In Oxy's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Natural Gas Simple Cycle Solar Centaur 40-4002 Turbines (Units ES-06/07 & ES-08/09)
- Natural Gas Simple Cycle Solar Centaur 40-4702 Turbine (Unit ES-10/11)
- Amine Gas Treating Units.[592]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[593] The following provides a review of the company's four-factor analyses. Comments on the four-factor analysis for the amine gas treating units are provided further below in Section XXIII.

A. Interest Rate Used in Cost Analyses.

Oxy used a 5.5% interest rate in the cost analyses for all of the controls evaluated in its 4-factor analyses.[594] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. This is the same interest rate that EPA has used in its cost spreadsheet for SCR, but EPA also states that the interest rate used in cost effectiveness analyses should be the bank prime interest

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[588] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand and Curve Reset, at 9.
[589] Title V Operating Permit No. P103-R3, OXY USA WTP Limited Partnership Indian Basin Gas Plant, 11/1/2019, at A3.
[590] *Id.*
[591] *Id.* at A7-A8.
[592] November 2019 Regional Haze Four-Factor Analysis for Oxy Indian Basin Gas Plant at 1-2.
[593] *Id.*
[594] *Id.* at Appendix B Cost Analysis Calculations.

rate.[595] The current bank prime rate is 3.25%.[596] The highest the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[597] In a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[598] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. For these reasons, in the cost effectiveness calculations provided herein, a 4.7% interest rate is used rather than a 5.5% interest rate.

B. Natural Gas Simple Cycle Solar Centaur 40-4002 Turbines (Units ES-06/07, ES-08/09, and ES-10/11)

The combustion turbines evaluated for controls at the Indian Basin Gas Plant are all Solar Centaur turbines that were manufactured in 1980.[599] The turbines have a permitted capacity of 4000 hp (Units ES-06/07 and ES-08/09) and 4700 hp (Unit ES-10/11).[600] The units each are either routed to a heat recovery generator or a bypass stack.[601] Units ES-06/07 and ES-08/09 are each subject to a NOx limit of 15.4 lb/hr and 67.4 tpy, and Unit ES-10/11 is subject to a 23.7 lb/hr NOx limit and 104.0 tpy.[602]

Oxy only evaluated one control technology for the combustion turbines: SoLoNOx combustion technology. Oxy did not evaluate SCR. Yet, SCR is a technically feasible control technology for combustion turbines.

1. Evaluation of SoLoNOx for Solar Centaur Turbines at Indian Basin Gas Plant

Oxy states that SoLoNOx is available for the existing Solar Centaur combustion turbines, but it would require the 4002 turbines at Units ES-06/07 and ES-08/09 to be uprated to model 4702 to support the SoLoNOx technology.[603] Oxy states that such controls could reduce NOx to 25

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[595] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[596] https://www.federalreserve.gov/releases/h15/.
[597] https://fred.stlouisfed.org/series/DPRIME.
[598] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.
[599] Title V Operating Permit No. P103-R3, OXY USA WTP Limited Partnership Indian Basin Gas Plant, 11/1/2019, at A7.
[600] *Id.*
[601] *Id.*
[602] *Id.* at A10.
[603] November 2019 Regional Haze Four-Factor Analysis for Indian Basin Gas Plant at 2-3.

ppm.[604] Based on a comparison to Oxy's reported recent testing data for the units, SoLoNOx would reduce NOx by 75% at Units ES-06/07 and ES-08/09 and by 84% at Unit ES-10/11. It also must be noted that Oxy's capital cost estimates for installation of SoLoNOx at Units ES-06/07 and ES-08/09 (Solar Centaur T4002 turbines) are significantly higher than the costs to upgrade the same model turbines at Kutz Canyon Gas Plant. Specifically, Units 1-6 at Kutz Canyon Gas Plant are the same model turbines (Solar Centaur T4002) and would also need to be uprated to model T4702 with the installation of SoLoNOx.[605] Yet, Harvest Four Corners identified the capital cost for SoLoNOx at Units 1-6 of the Kutz Canyon facility as $467,400 with annual operations and maintenance costs of $22,500[606] whereas Oxy identified the capital cost for SoLoNOx at the same model turbines at Units ES-06/07 and ES-08/09 three times as much at $1,510,295 and with a higher operations and maintenance cost of $30,407 per year.[607]

While Oxy submitted supplemental information to NMED in a February 2020 submittal, the supplemental information appears to be for a different turbine model and also is from four years ago. Specifically, in response to NMED's request for the vendor specifications for the SoLoNOx costs and emission rate guarantee, Oxy submitted a sheet on "Predicted Emission Performance" for SoLoNOx at a Centaur 40-4700S turbine with a NOx emission rate of 42 ppmvd and submitted cost data as confidential business information for a "similar unit that was installed at the facility."[608] Yet, the turbines being reviewed in this four-factor analysis are of a different model and of a model for which a 25 ppm NOx emission rate was evaluated for SoLoNOx. NMED must collect more current cost information as to why SoLoNOx at the combustion turbines currently being evaluated for controls at Indian Basin Gas Plant would cost three times as much at the Indian Basin Solar Centaur T4002 gas turbines compared to the Kutz Canyon Solar Centaur T4002 gas turbine

In terms of the life of SoLoNOx controls in the cost effectiveness analyses, Oxy's analysis assumed a 20-year life. For the reasons described above on the evaluation of dry low NOx combustors at the gas turbines at the Chaco Gas Plant, a 25-year life is a more appropriate assumption for the cost effectiveness analysis.[609] In the table below, we revised Oxy's cost effectiveness analyses of SoLoNOx were revised to take into account a longer lifetime of controls and a lower 4.7% interest rate.

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[604] *Id.*
[605] November 2019 Regional Haze Four-Factor Analysis for Harvest Four Corners Kutz Canyon Gas Plant at 2-3.
[606] *Id.* at Appendix B (pdf 30 of document).
[607] November 2019 Regional Haze Four-Factor Analysis for Indian Basin Gas Plant at Appendix B (pdf pages 21-22 of document).
[608] February 2020 Four-Factor Addendum for Oxy Indian Basin Gas Plant at pdf page 3 and at Appendix A. Cost data in Appendix B is not publicly available.
[609] *See also* NPCA March 2020 Oil and Gas Four-Factor Report at 69-70.

Table 37. Revised Cost Effectiveness of SoLoNOx at Units ES-06/07, ES-08/09, and ES-10/11 of the Indian Basin Gas Plant, to Reflect a 4.7% Interest Rate and a 25-Year Life

Unit	Oxy's Total Annual Costs of SoLoNOx (at 5.5% Interest and 20-Year Life)	Oxy's Cost Effectiveness at 5.5% Interest and 20 Year Life	Revised Total Annual Costs of SoLoNOx	Revised Cost Effectiveness at 4.7% Interest and 25 Year Life
ES-06/07	$156,787	$3,809/ton	$134,367	$3,265/ton
ES-08/09	$156,787	$4,132/ton	$134,367	$3,542/ton
ES-10/11	$147,290	$1,834/ton	$127,096	$1,582/ton

Thus, the cost effectiveness of SoLoNOx at the Solar Centaur turbines based on Oxy's capital cost of SoLoNOx should be in the range of $1,582/ton to $3,542/ton assuming a more appropriate 25-year life at lower interest rate. However, assuming that the costs of SoLoNOx are instead the same as the capital and operating and maintenance costs for SoLoNOx (including uprating of the turbines) of the same model turbine (Solar T4002) at the Kutz Canyon plant, the cost effectiveness of SoLoNOx at Units ES-06/07 and 08/09 would be $1,328/ton at Unit ES-06/07 and $1,441/ton at Unit ES-08/09. It is thus imperative that NMED determine why Oxy's cost estimates for SoLoNOx at these units are so much more expensive as the costs for controls (and turbine uprates) at the same model turbines as Units 1-6 of the Kutz Canyon Gas Plant.

2. Evaluation of SCR for the Solar Centaur Combustion Turbines at the Indian Basin Gas Plant

Oxy did not evaluate SCR as a control option for any of the combustion turbines at Indian Basin Gas Plant. Oxy acknowledged that Solar Turbines indicated that SCR is an available technology for the Solar Centaur turbines at Indian Basin Gas Plant, but Oxy determined that the additional power demands of SCR make the controls infeasible because the power at the plant would "need to be upgraded significantly and re-designed in order to power the SCR controls."[610] If the power at the plant would need to be upgraded to accommodate SCR, that should be evaluated as part of the cost of SCR rather than deem the control as technically infeasible. Further, NMED should request information from Oxy to determine whether the power would need to be upgraded for SCR systems at just one combustion turbine, or if the company's claim of power supply upgrades apply to SCR systems installed at all three combustion turbines. SoLoNOx at Unit ES-10/11 is very cost effective and will reduce NOx by 84%. Thus, it is likely SCR is the better control choice just for units ES-06/07 and ES-08/09, for which SoLoNOx has higher cost effectiveness values and will only result in 75% control. NMED should request that Oxy look into the option of shared SCR reactor for these two units, which could reduce electricity needs as well as reduce costs of control.

SCR would be more effective at reducing NOx at the Solar Centaur combustion turbines than SoLoNOx. As presented NPCA's Oil and Gas Four-Factor Report, NESCAUM assumed 90%

[610] November 2019 Regional Haze Four-Factor Analysis for Indian Basin Gas Plant at 2-4.

control with SCR in its 2000 Status Report to control small gas turbines down to 15 ppmv.[611] SCR at Units ES-06/07 and ES-08/09 of the Indian Basin Gas Plant should be able to at least achieve a 15 ppmv NOx limit, which reflects 85% NOx control at each unit.

Based on the fact that the combustion turbines at its Eunice Gas Plant (Units 17A, 18B, 19A, 25A, and 26A) evaluated for SCR by DCP Midstream are of similar size as the Indian Basin Gas Plant turbines, one would expect SCR to have a similar cost effectiveness. As shown in Table 9 above, the cost effectiveness SCR at the DCP Eunice Gas Plant turbines ranged from $2,600/ton to $3,800/ton (assuming a 4.7% interest rate and 25-year life). Thus, one would expect the similar (or same) model turbine and similar size units at Indian Basin Gas Plant combustion turbines to have a similar cost effectiveness of SCR to achieve 15 ppmv at 15% O_2.

Moreover, SCR combined with SoLoNOx, which is commonly required to meet BACT for gas turbines, could reduce NOx by 97% or more. As discussed in Section I.C.2 of this report, this combination of NOx controls has been permitted for the Buckingham Compressor Station to achieve a NOx emission rates of 3.75 ppmv @ 15% oxygen.[612] However, emission rates with SoLoNOx and SCR at gas-fired combustion turbines could be even lower, as BACT or LAER for such turbines operated for power generation are generally set at 2 to 2.5 ppmv at 15% oxygen.[613] NMED should require Oxy to evaluate the cost effectiveness of the combination of SoLoNOx and SCR to achieve the greatest level of NOx reduction.

XVII. Enterprise South Carlsbad Compressor Station

The Enterprise South Carlsbad Compressor Station is a natural gas compressor station and dew point plant.[614] According to a January 2020 NMED Statement of Basis for a Title V Permit modification,[615] after compression, the gas is sent to an amine unit to remove CO2. Water is then removed from the treated gas from the amine unit by routing through a glycol dehydrator. Salable hydrocarbons are then removed. The compressed gas then has liquids removed in a three-phase separator. Dry gas is sent into a pipeline for transport. The gas stream from the three-phase separator is used as turbine fuel along with other fuel if needed from the discharge residue gas stream or the gas stream from the condensate stabilizer. The facility is located

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[611] NPCA March 2020 Oil and Gas Four-Factor Report at 74-75. *See also* NESCAUM, December 2000, Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, Technologies & Cost Effectiveness at III-21 through III-24 and at III-40 (see referenced 11, 16, 9, 14, and 15), available at http://www.nescaum.org/documents/nox-2000.pdf/view.

[612] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.

[613] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand and Curve Reset, at 9.

[614] NMED Statement of Basis, Title V Minor Modification, Enterprise Fields Services, LLC, South Carlsbad Compressor Station, 1/10/2020, at 1.

[615] *Id.*

about 2.8 miles northwest of Loving, New Mexico in Eddy County.[616] The plant consists of two compressors driven by natural gas-fired combustion turbines, a glycol reboiler, an amine heater, tanks, and a flare, among other air emissions sources.[617]

In Enterprise's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Solar Centaur T4702 Turbines (Units 1 and 2).[618]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[619] The following provides a review of the company's four-factor analyses.

A. Interest Rate Used in Cost Analyses.

Enterprise used an 8.38% interest rate in the cost analyses for the controls evaluated in its 4-factor analyses.[620] This is an unreasonably high interest rate for cost effectiveness analyses. EPA's Control Cost Manual indicates that the interest rate used in cost effectiveness analyses should be the bank prime interest rate.[621] The current bank prime rate is 3.25%.[622] The highest the bank prime rate has been in the past five years is 5.5%, and that was only for a period of 7-8 months in 2019 out of the past five years.[623] In NPCA's March 2020 Oil and Gas Four-Factor Report, an interest rate of 5.5% was used to reflect the highest the bank prime interest rate has been in the past five years. However, in a cost effectiveness analyses being done today, even a 5.5% interest rate is unreasonably high, given the current bank prime lending rate of 3.25%. In a recent four-factor cost effectiveness analysis for reasonable progress controls, the owner of Craig Power Plant in Colorado (Tri-State Generation & Transmission) used an interest rate of 4.7%.[624] That tracks closely with the 4.75% interest rate that was in place before the global COVID-19 pandemic. Thus, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls. Enterprise's use of an 8.38% interest rate is unreasonably high and overstates the cost effectiveness of pollution controls evaluated in the four-factor analyses.

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[616] Title V Permit No. P130-R3 issued 3/8/18 for South Carlsbad Compressor Station at A3.
[617] *Id.* at A6-A7.
[618] November 2019 Regional Haze Four-Factor Analysis for South Carlsbad Compressor Station at 1-2.
[619] *Id.*
[620] *Id.* at Section 8.0 Supporting Documentation.
[621] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.
[622] https://www.federalreserve.gov/releases/h15/.
[623] https://fred.stlouisfed.org/series/DPRIME.
[624] December 6, 2019 Tri-State Four-Factor Analysis Craig Station Units 2 and 3, Appendix C.

B. Solar Centaur T4702 Turbines (Units 1 and 2)

The combustion turbines evaluated for controls at the South Carlsbad Compressor Station are both model T4702 Solar Centaur turbines that were manufactured in 2004.[625] The turbines have a permitted capacity of 4328 hp and a heat input of 42.8 MMBtu/hr.[626] The units each power a compressor engine.[627] The units are each subject to a NOx limit of 27.0 lb/hr and 90.8 tpy.[628]

Enterprise only evaluated one control technology for the combustion turbines: SoLoNOx combustion technology. Enterprise did not evaluate SCR. Yet, SCR is a technically feasible control technology for combustion turbines.

1. Evaluation of SoLoNOx for Solar Centaur Model T4702 Turbines

Enterprise states that SoLoNOx is available for the existing Solar Centaur model T4702 combustion turbines and that the controls could reduce NOx to 25 ppm.[629] Oxy states that such controls could reduce NOx to 25 ppm.[630] According to Enterprise's Four-Factor Analysis, SoLoNOx would reduce NOx by 64% at Unit 1 and by 66% at Unit 2.[631]
In terms of the life of SoLoNOx controls in the cost effectiveness analyses, Enterprise's analysis assumed a 20-year life. For the reasons described above on the evaluation of dry low NOx combustors at the gas turbines at the Chaco Gas Plant, a 25-year life is a more appropriate assumption for the cost effectiveness analysis.[632] In the table below, we revised Enterprise's cost effectiveness analyses of SoLoNOx were revised to take into account a longer lifetime of controls and a lower 4.7% interest rate.

Table 38. Revised Cost Effectiveness of SoLoNOx at Units 1 and 2 of the South Carlsbad Compressor Station, to Reflect a 4.7% Interest Rate and a 25 Year Life

Unit	Enterprise's Total Annual Costs of SoLoNOx (at 5.5% Interest and 20-Year Life)	Enterprise's Cost Effectiveness at 5.5% Interest and 20 Year Life	Revised Total Annual Costs of SoLoNOx	Revised Cost Effectiveness at 4.7% Interest and 25 Year Life
1	$178,387	$8,584/ton	$130,180	$6,265/ton
2	$178,387	$6,629/ton	$130,180	$4,838/ton

[625] Title V Permit No. P130-R3 issued 3/8/18 for South Carlsbad Compressor Station at A6
[626] *Id.*
[627] *Id.*
[628] *Id.* at A9.
[629] November 2019 Regional Haze Four-Factor Analysis for South Carlsbad Compressor Station at 2-2.
[630] *Id.*
[631] *Id.* at 3-1.
[632] *See also* NPCA March 2020 Oil and Gas Four-Factor Report at 69-70.

Thus, the cost effectiveness of SoLoNOx at the Solar Centaur T4702 turbines should be in the range of $4,800/ton to $6,200/ton assuming a more appropriate 25-year life at lower interest rate. The cost effectiveness of SoLoNOx at Units 1 and 2 of the South Carlsbad Compressor Station are much higher than the cost effectiveness of SoLoNOx at Unit ES-10/11 of the Indian Basin Gas Plant, despite the turbine models being the same Solar Centaur T4702 model. It appears this is due to the low 2016 emission rates of the Units 1 and 2 at the South Carlsbad Compressor Station. As discussed in Section I.B.1. of this report, it is imperative that NMED ensure that the emissions considered as baseline emission for cost effectiveness analyses be a reasonable estimate of current and future NOx emissions. The 2016 emissions reported by Enterprise for Units 1 and 2 are less than half of the NOx emission limits for the units, despite the units both operating 8,544 hours in 2016 (or 97.2% of the available hours in a year). These low 2016 NOx emissions either reflect the need to reduce the allowable emission limits for the units to more accurately reflect current emissions levels or the 2016 emissions data may not have been measured when the units were operating at maximum capacity. If the baseline NOx emissions are going to make the difference for NMED as to whether a pollution control is cost effective or not (especially if that pollution control is considered to be cost effective for other similar size or same model turbines, then NMED must ensure that the cost effectiveness analyses for pollution controls evaluated for the company's four-factor analyses are based on an accurate estimate of emissions expected in 2028.

2. Evaluation of SCR for the Solar Centaur T4702 Turbines at the South Carlsbad Compressor Station

Enterprise did not evaluate SCR as a control option for the Units 1 and 2 combustion turbines. Enterprise states the South Carlsbad facility was designed and constructed without plans for installation of SCR, and that based on size estimated provided by CECO-Peerless, Enterprise determined that it is "not possible" to install SCR at Units 1 and 2 of the South Carlsbad Compressor Station.[633]

While the facility and gas turbines may not have been originally designed to have space to accommodate SCR, that is typically the case with most SCR retrofits. As such, there have been numerous SCR retrofits installations at various industrial facilities that have had to overcome space constraints. For example, for many large coal-fired power plants, SCR reactors have been elevated above the air preheaters. Indeed, a report about SCR retrofits at GE LM2500 turbines at Chevron's Eastridge Cogeneration plant in California showed that some significant changes to the facility had to be made to accommodate SCR, including cutting the duct between economizers and moving the stack and one economizer onto new foundations to make way for the SCR reactor.[634] Thus, before NMED accepts a very brief claim of retrofit difficulty of SCR at any emissions unit being evaluated for reasonable progress controls, it is imperative that NMED ask Enterprise for a site plan and photos that shows whatever space constraints are being

[633] November 2019 Regional Haze Four-Factor Analysis for South Carlsbad Compressor Station at 2-3.
[634] *See* Seebold, James et al., Gas Turbine NOx Reduction Retrofit, , available at https://www.onepetro.org/conference-paper/SPE-66501-MS.

claimed, and that NMED ask Enterprise to consult with SCR vendors for options for SCR installation at the gas turbines of South Carlsbad Compressor Station. In addition, there may be other options for the location of the SCR system. Depending on the proximity of the gas turbines, it is possible that one SCR reactor could be used by both Units 1 and 2, which would reduce costs and potentially be easier to install at the site. NMED must require all possibilities for SCR installation be evaluated and documented by Enterprise. The state must not simply discount this highly effective NOx control based on a claim of some retrofit difficulty.

SCR would be more effective at reducing NOx at the South Carlsbad combustion turbines than SoLoNOx. As presented NPCA's Oil and Gas Four-Factor Report, NESCAUM assumed 90% control with SCR in its 2000 Status Report to control small gas turbines down to 15 ppmv.[635] That would reflect a 78% reduction in NOx emissions at Units 1 and 2. However, because SCR can achieve NOx reductions of 90%, SCR could be even more effective at reducing NOx from these units.

Based on the fact that the combustion turbines at its Eunice Gas Plant (Units 17A, 18B, 19A, 25A, and 26A) evaluated for SCR by DCP Midstream are of similar size as the South Carlsbad Compressor Station turbines, one would expect SCR to have a similar cost effectiveness. As shown in Table 9 above, the cost effectiveness SCR at the DCP Eunice Gas Plant turbines ranged from $2,600/ton to $3,800/ton (assuming a 4.7% interest rate and 25-year life). Thus, one would expect the similar (or same) model turbine and similar size units at Indian Basin Gas Plant combustion turbines to have a similar cost effectiveness of SCR to achieve 15 ppmv at 15% O_2.

Moreover, SCR combined with SoLoNOx, which is commonly required to meet BACT for gas turbines, could reduce NOx by 97% or more. As discussed in Section I.C.2 of this report, this combination of NOx controls has been permitted for the Buckingham Compressor Station to achieve a NOx emission rates of 3.75 ppmv @ 15% oxygen.[636] However, emission rates with SoLoNOx and SCR at gas-fired combustion turbines could be even lower, as BACT or LAER for such turbines operated for power generation are generally set at 2 to 2.5 ppmv at 15% oxygen.[637] NMED should require Enterprise to evaluate the cost effectiveness of the combination of SoLoNOx and SCR to achieve the greatest level of NOx reduction.

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[635] NPCA March 2020 Oil and Gas Four-Factor Report at 74-75. *See also* NESCAUM, December 2000, Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, Technologies & Cost Effectiveness at III-21 through III-24 and at III-40 (see referenced 11, 16, 9, 14, and 15), available at http://www.nescaum.org/documents/nox-2000.pdf/view.

[636] See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-forbuckingham-county-compressor-station-vacated.

[637] *See*, e.g., Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand and Curve Reset, at 9.

XVIII. El Paso Natural Gas Company – Blanco Compressor Station A

The El Paso Natural Gas Company, LLC. (EPNG) Blanco Compressor Station A is located in San Juan County. NMED has described the facility processes as follows:

The Blanco Compressor Station A is a natural gas compressor station that compresses natural gas for the purpose of transportation to another facility or a major transportation pipeline.[638]

According to the permit, the plant includes 14 2-stroke lean-burn reciprocating internal combustion engines (RICE).[639] In EPNG's four-factor submittal, the company evaluated air pollution controls for these units:

- Cooper-Bessemer 2SLB RICE GMV10-TF: Units A01 through A14.[640]

The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses.[641] The following provides a review of the company's four-factor analyses.

A. Units A01 through A14: Cooper-Bessemer GMV10-TF 2-Stroke Lean-Burn Compressor Engines

Units A01 through A14 are 2-stroke lean-burn RICE that were constructed in 1953, each with a capacity of 943 hp.[642] The units each have an hourly NOx limit of 21.9 lb/hr and an annual NOx limit of 95.97 tpy.[643]

1. Use of Low Emission Combustion Technology

EPNG presents three options for reducing NOx emissions from these compressor engines, with varying low emission combustion (LEC) control techniques to meet NOx emission levels of 3 g/hp-hr, 1 g/hp-hr, and 0.5 g/hp-hr. Uncontrolled NOx emissions (tpy) are based on 2016 emissions. The 2016 actual emissions for these units and the allowable NOx emission rates are shown in the table below.[644]

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[638] Title V Operating Permit P048-R3 for Blanco Compressor Station A at 4.
[639] *Id.* at 6-7.
[640] October 2019 Regional Haze Four-Factor Analysis for El Paso Natural Gas Company, LLC Blanco Compressor Station A at 5.
[641] *Id.* at 3.
[642] Title V Operating Permit P048-R3 for Blanco Compressor Station A at 6-7.
[643] *Id.* at 8.
[644] October 2019 Regional Haze Four-Factor Analysis for El Paso Natural Gas Company, LLC Blanco Compressor Station A at 5.

Table 39. EPNG Blanco Compressor Station A 2SLB RICE Unit NOx Emission Rates

Unit	Size [hp]	Allowable NOx Emissions [tpy]	2016 NOx Emissions [tpy]
A01	943	95.97	73.711
A02	943	95.97	0.025
A03	943	95.97	54.915
A04	943	95.97	1.093
A05	943	95.97	3.081
A06	943	95.97	0.613
A07	943	95.97	65.341
A08	943	95.97	0.019
A09	943	95.97	27.382
A10	943	95.97	0.019
A11	943	95.97	48.253
A12	943	95.97	0.016
A13	943	95.97	82.061
A14	943	95.97	0.019

It appears that many of these units operate infrequently, with several emitting less than 1 tpy in 2016. NMED should request more information on the typical operating schedules for these engines to ensure that EPNG's four-factor analysis is based on usage that is expected in 2028.

EPNG's four-factor analysis is based on detailed cost estimates for retrofitting these units with LEC technologies; control costs include capital costs and net annual costs (annual recurring costs).[645] EPNG does not provide any details on the source of the cost information included in the four-factor analysis; we assume they represent current costs (2019$). These cost estimates are high, at $138—$217/hp, compared to other capital cost estimates for LEC controls at other similar engines.[646] EPNG presents cost effectiveness, in dollars per ton of NOx reduced, ranging from $32K/ton to as high as $2.9M/ton.[647] However, these cost effectiveness figures do not take into account the annualized costs over the lifetime of the controls, they are simply the total per unit capital cost divided by the NOx emissions reductions from 2016 emissions. The following three tables present the cost effectiveness based on EPNG's capital cost estimates—for Options 1, 2, and 3—annualized over the life of the controls. Note, this updated analysis uses an interest rate of 4.7%, reflective of current and likely near future interest

[645] *Id.* at 4 and 10.
[646] *See, e.g.,* Four-Factor analyses for Saunders Gas Plant (Cooper-Bessemer 2SLB RICE at $90-$138/hp), Roswell Compressor Station No. 9 (Cooper-Bessemer 4SLB RICE at $90/hp), and Jal No. 3 (Cooper-Bessemer 2SLB RICE at $123/hp).
[647] *Id.*

rates.[648] Further note, the LEC controls are assumed to last 25 years, consistent with other cost effectiveness analyses submitted to NMED for LEC controls.[649]

Table 40. Cost Effectiveness of LEC at Uncontrolled Blanco Compressor Station A Units A01 through A14 for Option 1 (3 g/hp-hr), Assuming a 4.7% Interest Rate and a 25-Year Life

Unit	Capital Cost of LEC to Reduce NOx Option 1 3 g/hp-hr [assuming 2019$]	Total Annualized Costs	NOx Removed, tpy Based on 2016 Source Data	Cost Effectiveness of LEC at 3 g/hp-hr [2019$], $/ton
A01	$1,884,728	$129,734	52.718	$2,461
A02	$1,884,728	$129,734	0.018	$7,207,430
A03	$1,884,728	$129,734	39.275	$3,303
A04	$1,884,728	$129,734	0.782	$165,900
A05	$1,884,728	$129,734	2.204	$58,863
A06	$1,884,728	$129,734	0.439	$295,521
A07	$1,884,728	$129,734	46.732	$2,776
A08	$1,884,728	$129,734	0.014	$9,266,695
A09	$1,884,728	$129,734	19.584	$6,624
A10	$1,884,728	$129,734	0.014	$9,266,695
A11	$1,884,728	$129,734	34.511	$3,759
A12	$1,884,728	$129,734	0.012	$10,811,145
A13	$1,884,728	$129,734	58.690	$2,210
A14	$1,884,728	$129,734	0.014	$9,266,695

Table 41. Cost Effectiveness of LEC at Uncontrolled Blanco Compressor Station A Units A01 through A14 for Option 2 (1 g/hp-hr), Assuming a 4.7% Interest Rate and a 25-Year Life

Unit	Capital Cost of LEC to Reduce NOx Option 2 1 g/hp-hr [assuming 2019$]	Total Annualized Costs	NOx Removed, tpy Based on 2016 Source Data	Cost Effectiveness of LEC at 1 g/hp-hr [2019$], $/ton
A01	$2,975,000	$204,782	66.713	$3,070
A02	$2,975,000	$204,782	0.022	$9,308,261
A03	$2,975,000	$204,782	49.701	$4,120
A04	$2,975,000	$204,782	0.989	$207,059
A05	$2,975,000	$204,782	2.789	$73,425
A06	$2,975,000	$204,782	0.555	$368,976
A07	$2,975,000	$204,782	59.138	$3,463

[648] As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.

[649] See 2019 Four-Factor submittals for Roswell Compressor Station and Jal No. 3 which both assume 25-year life of controls for LEC.

Unit	Capital Cost of LEC to Reduce NOx Option 2 1 g/hp-hr [assuming 2019$]	Total Annualized Costs	NOx Removed, tpy Based on 2016 Source Data	Cost Effectiveness of LEC at 1 g/hp-hr [2019$], $/ton
A08	$2,975,000	$204,782	0.017	$12,045,984
A09	$2,975,000	$204,782	24.783	$8,263
A10	$2,975,000	$204,782	0.017	$12,045,984
A11	$2,975,000	$204,782	43.673	$4,689
A12	$2,975,000	$204,782	0.015	$13,652,116
A13	$2,975,000	$204,782	74.271	$2,757
A14	$2,975,000	$204,782	0.017	$12,045,984

Table 42. Cost Effectiveness of LEC at Uncontrolled Blanco Compressor Station A Units A01 through A14 for Option 3 (0.5 g/hp-hr), Assuming a 4.7% Interest Rate and a 25-Year Life

Unit	Capital Cost of LEC to Reduce NOx Option 3 0.5 g/hp-hr [assuming 2019$]	Total Annualized Costs	NOx Removed, tpy Based on 2016 Source Data	Cost Effectiveness of LEC at 0.5 g/hp-hr [2019$], $/ton
A01	$2,804,837	$193,069	70.212	$2,750
A02	$2,804,837	$193,069	0.023	$8,394,291
A03	$2,804,837	$193,069	52.308	$3,691
A04	$2,804,837	$193,069	1.041	$185,465
A05	$2,804,837	$193,069	2.935	$65,781
A06	$2,804,837	$193,069	0.584	$330,597
A07	$2,804,837	$193,069	62.240	$3,102
A08	$2,804,837	$193,069	0.018	$10,726,039
A09	$2,804,837	$193,069	26.082	$7,402
A10	$2,804,837	$193,069	0.018	$10,726,039
A11	$2,804,837	$193,069	45.963	$4,201
A12	$2,804,837	$193,069	0.016	$12,066,794
A13	$2,804,837	$193,069	78.166	$2,470
A14	$2,804,837	$193,069	0.018	$10,726,039

For many of these units, LEC controls can be cost effective for reducing NOx emissions to emission rates as low as 0.5 g/hp-hr. NMED must request a revised four-factor analysis from EPNG for the Blanco Compressor Station A that includes the annualization of costs. Also, NMED should request additional information on the usage of these engines to determine if the units are consistently used as in 2016 or if usage varies from year to year. NMED must ensure that the cost effectiveness analyses for LEC evaluated for the company's four-factor analyses are based on a more comprehensive representation of emissions reduction and operating hours expected in 2028.

2. Use of SCR

EPNG did not evaluate SCR for Units A01 through A14 primarily because it claimed that it was not technically feasible for this engine type.[650] As discussed above regarding the combustion turbines at the Chaco Gas Plant, before NMED dismisses SCR as a possible regional haze control, it must request more information and documentation. Specifically, NMED must 1) ask for site photographs, plot plans, dimensions of buildings and open spaces, etc., and 2) ask for SCR vendor analyses for SCR installation options at these units, including any potential options for a shared SCR system between the units. SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. It should not be summarily dismissed as not feasible for these engines, particularly because EPNG has not found LEC to be a cost effective NOx reduction strategy for some of these units.

In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[651]

If LEC technology is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[652] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[653] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should not discount SCR as a potentially viable control option for lean burn engines in its analysis of available controls to achieve reasonable progress towards the national visibility goal.

XIX. Transwestern Pipeline Company Roswell Compressor No. 9

The Transwestern Pipeline Company (Transwestern) Roswell Compressor Station No. 9 is a natural gas compressor station located about 5 miles north of Roswell, New Mexico in Chaves

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[650] October 2019 Regional Haze Four-Factor Analysis for El Paso Natural Gas Company, LLC Blanco Compressor Station A at 9.

[651] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.

[652] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.

[653] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

County.[654] The plant consists of two natural gas-fired four-stroke lean-burn compressor engines compressors and a natural gas-fired rich burn engine used as a generator, as well as several tanks and other emissions sources.[655] The compressor station also has two electric-driven compressor engines with no associated air emissions.[656] In Transwestern's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Two Four-Stroke Lean-Burn RICE (Units 903 and 904).[657]

The rich burn generator engine is used as an emergency generator and operates less than 100 hours per year, and so was not evaluated for controls.[658] The selection of these engines for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses. The following provides a review of the company's four-factor analyses.

A. Lean Burn Natural Gas-Fired Compressor Engines (Units 903 and 904)

The primary sources of NOx emissions at the Roswell Compressor Station No. 9 are two four-stroke lean burn natural gas-fired RICE (Units 903 and 904). The engines are both 4,500 hp Cooper-Bessemer LSV-16G compressor engines used for transportation of natural gas.[659] The engines were constructed in 1959, and are subject to allowable emission limits of 125 lb/hr and 547.5 tpy each.[660]

According to documentation submitted with the four-factor analysis, the 2016 emissions and operating hours used as baseline were as follows:

Table 43. Units 903 and 904 of Roswell Compressor Station No. 9 2016 Emissions and Operating Hours[661]

Unit No.	NOx Emission Rate, lb/hr	2016 Operating Hours	NOx Emissions, tpy
903	37.19 (Tested)	3,607	67.07
904	125 (PTE)	971	60.69

The source's Title V renewal application indicates that the allowable annual number of operating hours for Units 903 and 904 was increased from 6,620 to 8,760, which was the

[654] Title V Permit No. P154-R4, Roswell Compressor Station No. 9, 9/28/2018, at A3.
[655] *Id.* at A6.
[656] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[657] *Id.* at 2.
[658] *Id.*
[659] *Id.*
[660] Title V Permit No. P154-R4, Roswell Compressor Station No. 9, 9/28/2018, at A7.
[661] October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9, Appendix A at 1. Apparently, the company only had NOx emissions test data for Unit 903.

allowable number of hours in Permit No. P154-R2M1.[662] So presumably the 2016 operating hours are lower than what might be expected in current and future years for these units, especially for Unit 904. And, in fact, a review of the facility's NOx emissions from 2016 through 2019 show an increase in NOx emissions as shown in the table below.

Table 44. Roswell Compressor Station No. 9 NOx Emissions 2016-2019, as Presented in NMED's Emissions Analysis Tool

2016	2017	2018	2019
74.4 tons	185.5 tons	136.5 tons	436.8 tons

NOx emissions are over five times higher in 2019 than they were in 2016. And NOx emissions in all years since 2016 are significantly higher. And it is safe to assume that the bulk of those NOx increases are coming from the Units 903 and 904 lean burn compressor engines, because the only other sources of NOx emissions at the compressor station are Unit 921 (four-stroke rich burn emergency generator engine operating less than 100 hours per year) and two thermal oxidizers. These three NOx sources are limited to a combined total NOx emissions of 27.54 tons per year.[663] Even if we assume that these three units emitted NOx at their allowable emissions of 27.54 tons per year total, that means over 400 tons of NOx were emitted in 2019 by Units 903 and 904, rather than the 127.76 tons per year in total assumed in Transwestern's four-factor cost effectiveness analysis.[664] NMED must ensure that Transwestern's cost effectiveness analysis of controls is based on emissions expected in 2028. Given the significant increases in emissions since 2016 and the permitted increased levels of operation, 2016 emissions should not be used as baseline emissions in the company's cost effectiveness analysis for controls. Use of more recent data would result in more favorable cost effectiveness values because of the increased reduction in NOx that would occur from more recent emissions levels.

1. Evaluation of Low Emissions Combustion for Units 903 and 904

Transwestern assumes a controlled NOx emission rate from LEC retrofits on units 903 and 904 of 2.5 g/hp-hr.[665] For unit 903, Transwestern reports that this represents a 33% reduction from baseline NOx emission rates that are based on the 2016 emissions inventory.[666] For unit 904, Transwestern reports that this represents an 80% reduction from the unit's permitted NOx emission rate; according to Transwestern, "permitted hourly NO_X emission rates were used for Unit 904 in this analysis due to the 2016 emissions inventory showing lower NO_X emission rates

[662] February 1, 2017 Title V Operating Permit Renewal Application, Permit P154-R3M1 Transwestern Pipeline Company, LLC Roswell Compressor Station No. 9 Section 3 Page 2.
[663] *See* Title V Permit No. P154-R4, Roswell Compressor Station No. 9, 9/28/2018, at A8.
[664] Note, Transwestern's four-factor analysis is based on PTE emissions for unit 904. Even so, actual emissions in 2019 are much higher that what was used in the company's four-factor analysis.
[665] October 2019 Regional Haze Four-Factor Analysis for Transwestern Pipeline Company, LLC Roswell Compressor Station No. 9 at 3 and Appendix A.
[666] *Id.* Appendix A.

than what was feasible to obtain by the engine vendor."[667] The permitted maximum hourly NOx emission rate of 125.0 lb/hr for these units is significantly higher than the 2016 emissions inventory data used for baseline emissions, even for unit 903. The allowable hourly NOx emission rate is equivalent to 12.6 g/hp-hr for these 4,500 hp engines. The source's Title V renewal application notes that the NOx emission factors are based on the permitted hourly rate in Permit No. P154-R2M1; it's not clear if the rates are based on stack testing or AP-42 emission factors but since all other emission factors (besides NOx) are identified as EPA AP-42 emission factors it's assumed that the permitted hourly rates are either based on stack tests or are source requested limits.[668] So for both units, emissions reductions to meet a controlled NOx rate of 2.5 g/hp-hr, based on a baseline emission rate that is reflective of the units' allowable emission rate, represents an 80% reduction in NOx emissions.

In January 2020, Transwestern submitted additional information in response to a request from NMED, including the specific technologies included in the quote from Cooper Machinery for LEC upgrades that lower NOx emissions to 2.5 g/hp-hr (e.g., precombustion chambers, turbocharger upgrades, larger intercoolers, etc.).[669]

It's possible that the controlled emission rate with LEC for these specific engines could be even lower that 2.5 g/hp-hr. NPCA's March 2020 Oil and Gas Four-Factor Report stated that a wide range of emission rates are achievable with LEC technology, with NOx emissions generally no higher than 2 g/hp-hr and often significantly lower (e.g., as low as 0.5 g/hp-hr).[670] EPA's Alternative Control Techniques document for RICE includes emissions test results for Clean Burn, low-emission retrofits (with a pre-combustion chamber) for LSV model dual-fuel engines demonstrating NOx emission rates of 2.0 g/hp-hr and as low as 1.27 g/hp-hr.[671] And, more generally, EPA's updated information on stationary RICE NOx emissions and control technologies concludes, for lean-burn engines, an emission rate of 2.0 g/bhp-hr is achievable for "new engines and most engines retrofitted with LEC technology."[672] Emissions reductions to meet a controlled NOx rate of 2 g/hp-hr, based on a baseline emission rate that is reflective of the units' allowable emission rate, represents an 84% reduction in NOx emissions.

Revising Transwestern's cost effectiveness analyses to reflect the quoted emissions reductions of 80% but based on potential operation at permitted levels for both units (not just for unit 904), results in more favorable cost effectiveness of these controls, as shown in the table below.

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[667] *Id.* at 1 and Appendix A.
[668] February 1, 2017 Title V Operating Permit Renewal Application, Permit P154-R3M1 Transwestern Pipeline Company, LLC Roswell Compressor Station No. 9 pdf page 39.
[669] January 23, 2020 Additional Information for Four Factor Analysis Roswell Compressor Station at 2.
[670] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 28.
[671] *See* EPA 1993 Alternative Control Techniques Document for RICE at 5-82 and 5-83.
[672] *Id.* at 4-12.

Table 45. Cost Effectiveness of LEC at Uncontrolled Roswell Compressor Station No. 9 Units 903 and 904 to Reduce NO_x Levels to 2.5 g/hp-hr, Assuming 80% Control

Unit	Size [hp]	Capital Cost of LEC [current vendor quote, assuming 2019$]	Annual O&M Costs (15% of Capital Costs) [2019$]	Total Annualized Costs of LEC to Reduce NOx to 2.5 g/hp-hr (80% NOx Reduction) [2019$]	Annual Operating Hours, hr/yr	NOx Removed, tpy	Cost Effectiveness of LEC [2019$], $/ton
903	4,500	$1,800,000	$270,000	$342,000	3,607	180	$1,896/ton
904	4,500	$1,800,000	$270,000	$342,000	971	49	$7,044/ton

Note, the cost effectiveness of LEC controls would be more favorable for unit 904 at higher operating hours and would be more feasible for both units if they were able to meet controlled emission rates below 2.5 g/hp-hr, which, as discussed earlier, has been demonstrated for other LEC retrofits for similar engines. NMED should request that Transwestern research other available retrofit options from additional vendors that may be able to guarantee NOx emission rates less than 2.5 g/hp-hr.

2. Evaluation of SCR for Units 903 and 904

Although Transwestern identified concerns with utilization of SCR for the lean burn engines (which included reagent injection control, exhaust temperature requirements, variations in exhaust NO/NO2 ratio, and engine oil carryover), Transwestern evaluated SCR as a NOx control option for the Units 903 and 904 engines.[673] In the May 21, 2020 Review of SCR Claims for Lean Burn Engines report, these issues and methods to resolve these concerns were addressed.[674] Transwestern said as a result of its stated concerns, LEC is the preferred control. Yet, the company's cost analysis showed that SCR was more cost effective, and it can achieve 90% NOx reduction.[675]

Transwestern appears to have used EPA's SCR Chapter of its Control Cost Manual to either estimate annual operations and maintenance costs of SCR and used a formula from the December 2000 NESCAUM Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines to estimate capital costs for SCR.[676]

[673] *Id.* at 3-4.
[674] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[675] October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 4-5 and Appendix A.
[676] December 2000 NESCAUM Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines at III-30.

Specifically, the NESCAUM formula which was based on only one case study for a RICE unit to "approximate" SCR capita costs for lean burn RICE is as follows:

$310,000 + ($72.7 x hp)[677]

This NESCAUM equation is twenty years old and is likely based on cost data from the 1990's. SCR has been implemented on numerous source types over the past twenty years, and the much wider-scale implementation and innovation in catalyst design has lowered the cost of SCR.[678] Yet, Transwestern's analysis escalated the capital costs developed with the above equation from the 2000 NESCAUM report by assuming the NESCAUM cost equation was based on 1994 costs and escalating to 2019, using the differences in the Consumer Price Index between 1994 and 2019.[679] EPA's Control Cost Manual cautions against escalating costs more than five years due to the potential for significant inaccuracies in price estimates.[680] EPA currently has a spreadsheet available to estimate the capital and operating costs for SCR. While the spreadsheet was developed for fossil fuel fired boilers, it can be used as an estimate for SCR at other natural gas-fired sources and, in fact, has been used oil and gas companies for several four-factor analyses submitted to NMED. Transwestern included the necessary information to be able to utilize the EPA SCR cost spreadsheet to estimate SCR costs for the Units 903 and 904 engines. Specifically, the company provided the hourly heat input in MMBtu/hr, the inlet NOx emission rate in lb/MMBtu, the engine fuel consumption in terms of Btu/hp-hr (with which the annual fuel consumption can be estimated based on the 2016 operating hours for each unit and each unit's rated horsepower of 4500), the flue gas flow rate in actual cubic feet per minute, and the SCR inlet temperature. The elevation for the location was estimated to be 3600 feet above sea level.

Using the unit-specific operating hours for 2016 and assuming 90% NOx reduction across the SCR, the cost effectiveness based on EPA's SCR spreadsheet is estimated as shown in the table below. Transwestern assumed a 25-year life of SCR, which was also assumed in the SCR cost effectiveness calculation presented below which is consistent with EPA's Control Cost Manual for the expected life of SCR at an industrial unit. For reasons discussed above in this report, a 4.7% interest rate was used rather than Transwestern's assumed 5.5% interest rate. (See, e.g., Section I.A. above).

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[677] *Id*.

[678] See EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.

[679] October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9, Appendix A (pdf pages 15 and 17 of report).

[680] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.

Table 46. Estimated Cost Effectiveness of SCR Using EPA's SCR Cost Spreadsheet and 2016 Operational Data for Units 903 and 904 Cooper-Bessemer LSV-16G Compressor Engines at Roswell Compressor Station No. 9 (25-Year Life, 4.7% Interest Rate), 2018 $

Unit Number	Capital Cost	Operations and Maintenance Costs	Total Annual Costs	NOx Reduced from 2016 Emissions, tpy	Cost Effectiveness
903	$1,778,670	$25,746	$150,853	60	$2,449/ton
904	$1,832,960	$26,173	$128,846	55	$2,835/ton

In comparison, Transwestern's SCR cost estimates are much higher. The table below provides the company's SCR cost estimates for comparison to Table 46 above.

Table 47. Transwestern's Cost Effectiveness of SCR for Units 903 and 904 Cooper-Bessemer LSV-16G Compressor Engines at Roswell Compressor Station No. 9 (25-Year Life, 5.5% Interest Rate), 2019 $[681]

Unit Number	Capital Cost	Operations and Maintenance Costs	Total Annual Costs	NOx Reduced from 2016 Emissions, tpy	Cost Effectiveness
903	$1,100,282	$218,527	$262,538	60	$4,376/ton
904	$1,100,282	$255,446	$299,457	55	$5,445/ton

Interestingly, EPA's SCR cost spreadsheet estimates a much higher capital cost than Transwestern's escalation of NESCAUM's capital cost equation for RICE units. But what makes most of the differences in the cost estimates is Transwestern's operations and maintenance costs. A review of the company's cost data sheet found two significant errors that lead to the overstatement of operations and maintenance costs. First, an error was made in the calculation of catalyst volume by Transwestern, due to an error in the formula used for the NOx efficiency adjustment factor η_{adj}. The formula for η_{adj} in EPA's Control Cost Manual chapter for SCR is:

$$\eta_{adj} = 0.2869 + (1.058 \underline{x} \eta_{NOx})$$ [682]

However, Transwestern used the formula

$$\eta_{adj} = 0.2869 + (1.058 \mathbf{+} \eta_{NOx})$$ [683]

Transwestern's error resulted in a significant overestimate of the volume of catalyst, in which η_{adj} is a multiplier, which then resulted in an overestimate of annual catalyst replacement costs.

[681] October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9, Appendix A (pdf pages 13-14 of report).
[682] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, at pdf page 61 (Equation 2.23).
[683] October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9, Appendix A (pdf pages 16 and 18 of report).

In addition, Transwestern assumed 8,760 hours per year of operation in determining annual operations and maintenance costs which significantly overstated the costs of reagent, catalyst replacement, and labor.[684]

In summary, SCR is a more cost effective NOx control for the Units 903 and 904 engines at Roswell Compressor No. 9 compared to LEC which Transwestern estimated would have a cost effectiveness of $7,000/ton to $15,000/ton.[685]

XX. Transwestern Pipeline Mountainair Compressor Station

The Transwestern Pipeline Company (Transwestern) Mountainair Compressor Station is a natural gas compressor station located in Torrance County, New Mexico. NMED has described the facility processes as follows:

> The facility is a natural gas compressor station. The station is equipped with three 4,500- horsepower (hp) Cooper-Bessemer LSV-16SG compressor engines (701-703) and two 335- hp Ingersoll-Rand PSVG-6 generator engines (721-722), a pipeline condensate storage tank (T-006), and a mist extractor (MIST).[686]

In Transwestern's Four-Factor submittal, the company evaluated air pollution controls for the following emission units:

- Cooper-Bessemer 4SLB RICE LSV-16G: Units 701, 702, and 703.[687]

The rich burn generator engines are equipped with NSCR and are achieving 85% reduction in NOx emissions based on recent engine performance testing.[688] The selection of the 4SLB RICE units for review was based on whether the engines had the potential to emit NOx in excess of 10 lb/hour or 5 tpy, which is the criteria established by NMED to identify sources subject to four-factor analyses. The following provides a review of the company's four-factor analyses.[689]

A. Lean Burn Natural Gas-Fired Compressor Engines (Units 701, 702, and 703)

The primary sources of NOx emissions at the Mountainair Compressor Station are three four-stroke lean-burn natural gas-fired RICE (Units 701, 702, and 703). The engines are each 4,500 hp Cooper-Bessemer LSV-16G compressor engines used for transportation of natural gas.[690]

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[684] *Id.* at pdf pages 15-18.
[685] *Id.* at pdf page 13.
[686] Title V Permit No. P153-R3M1, Mountainair Compressor Station, 9/26/2016, at 3.
[687] October 2019 Regional Haze Four-Factor Analysis for Transwestern Pipeline Company, LLC Mountainair Compressor Station at 2.
[688] *Id.*
[689] *Id.* at 1.
[690] Title V Permit No. P153-R3M1, Mountainair Compressor Station, 9/26/2016, at 5-6.

The engines were constructed in 1960 (701 and 701) and 1967 (703), and are subject to allowable emission limits of 165.3 lb/hr and 724.2 tpy each.[691]

1. Baseline Emissions for Units 701, 702, and 703

According to documentation submitted with the four-factor analysis, the 2016 emissions and operating hours used as baseline were as follows:

Table 48. Units 701, 702, and 703 of Mountainair Compressor Station 2016 Emissions and Operating Hours[692]

Unit No.	2016 NOx Emission Rate, lb/hr	2016 Operating Hours	2016 NOx Emissions, tpy	NOx Allowable Emissions, tpy	NOx Allowable Emissions, lb/hr
701	59.07	1,535	45.34	724.2	165.3
702	98.03	3,116	152.73	724.2	165.3
703	100.86	4,586	231.27	724.2	165.3
TOTAL	258.0	9,237	429.34	2,172.6	495.9

The company's 2016 NOx emissions, used as baseline emissions, are significantly lower than the units' allowable emission limits of 165.3 lb/hr and 724.2 tpy each. And more recent actual emissions from the facility are also much higher.

In fact, the facility obtained a permit in 2016 that allowed for a three-fold increase in startup, shutdown, maintenance, and malfunction emissions because the facility was operating more due to increased volume of natural gas being processed at the facility.[693] Prior to 2016, NMED referred to the compressor station as a "peaking station."[694] A review of the facility's NOx emissions from 2016 through 2019 show a dramatic increase in NOx emissions as shown in the table below.

Table 49. Mountainair No. 7 Compressor Station NOx Emissions 2016-2019, as Presented in NMED's Emissions Analysis Tool

2016	**2017**	**2018**	**2019**
436.6 tons	449.2 tons	1,048.1 tons	932 tons

NOx emissions have more than doubled since 2016 at the Mountainair No. 7 Compressor Station. The most recent two year average NOx emissions are 990.05 tons compared to 436.6 tons of NOx emitted in the 2016 base year used in Transwestern's cost analysis. And it is safe

[691] *Id.*
[692] October 2019 Regional Haze Four-Factor Analysis for Transwestern Pipeline Company, LLC Mounatinair Compressor Station Appendix A at 1.
[693] *See* 9/26/2016 NMED Statement of Basis -Narrative for Title V Permit Significant Permit Modification for Mountainair No. 7 Compressor Station (Permit No. P153-R3M1) at 1.
[694] *Id.* at 3.

to assume that the bulk of those NOx increases are coming from the Units 701, 702, and 702 lean burn compressor engines, because the only other sources of NOx emissions at the compressor station are Units 721 and 722 (four-stroke rich burn generator engines) that are limited to a combined total NOx emissions of 90.9 tons per year.[695] If we assume that Units 721 and 722 emitted NOx at their allowable emissions of 90.9 tons per year total (which is not likely to occur),[696] that means at least 899.15 tons of NOx were emitted on average over 2018 to 2019 by Units 701, 702, and 703, rather than the 429.34 tons per year in total assumed in Transwestern's four-factor cost effectiveness analysis. NMED must ensure that Transwestern's cost effectiveness analysis of controls is based on emissions expected in 2028. Given the significant increases in emissions since 2016 and the permitted increased levels of operation, 2016 emissions should not be used as baseline emissions in the company's cost effectiveness analysis for controls. Use of more recent data would result in lower cost effectiveness values because of the increased reduction in NOx that would occur from more recent emissions levels.

2. Evaluation of Low Emissions Combustion for Units 701, 702, and 703

Transwestern assumes a controlled NOx emission rate from LEC retrofits on units 701, 702, and 703 of 2.5 g/hp-hr.[697] This represents a 58% (unit 701) and 75% (units 702 and 703) NOx emissions reduction from baseline NOx emission rates that are based on the 2016 emissions inventory.[698] The permitted maximum hourly NOx emission rate of 165.3 lb/hr for these units is significantly higher than the 2016 emissions inventory data used for baseline emissions. The allowable hourly NOx emission rate is equivalent to 16.7 g/hp-hr for each of these 4,500 hp engines. No test data are provided for these units and the source's recent Title V modification application does not specify the basis for the source's allowable NOx emission limits.[699] For both units, emissions reductions to meet a controlled NOx rate of 2.5 g/hp-hr, based on a baseline emission rate that is reflective of the units' allowable emission rate, represents an 85% reduction in NOx emissions.

It's possible that the controlled emission rate with LEC for these specific engines could be even lower that 2.5 g/hp-hr. NPCA's March 2020 Oil and Gas Four-Factor Report stated that a wide range of emission rates are achievable with LEC technology, with NOx emissions generally no higher than 2 g/hp-hr and often significantly lower (e.g., as low as 0.5 g/hp-hr).[700] EPA's

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[695] *See* 9/26/2016 Title V Operating Permit No. P153-R3M1 for Mountainair Compressor Station (Station No. 7) at 3 and at 5-7.

[696] For example, in 2016, Units 701, 702, and 703 emitted 429.34 tons (based on what was reported for these units' 2016 emissions in the Mountainair No 7 Compressor Station Four-Factor Analysis in Appendix A). The total reported NOx emissions as shown in Table 49 above were 436.6 tons, which would mean Units 721 and 722 only emitted 7.26 tons of NOx in 2016.

[697] October 2019 Regional Haze Four-Factor Analysis for Transwestern Pipeline Company, LLC Mounatinair Compressor Station at 3 and Appendix A.

[698] *Id.* Appendix A.

[699] *See* March 3, 2016 Title V Operating Permit Application for Significant Modification, Permit P153-R3 Transwestern Pipeline Company, LLC Mountainair Compressor Station Section 6, Page 4.

[700] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 28.

Alternative Control Techniques document for RICE includes emissions test results for Clean Burn, low-emission retrofits (with a pre-combustion chamber) for LSV model dual-fuel engines demonstrating NOx emission rates of 2.0 g/hp-hr and as low as 1.27 g/hp-hr.[701] And, more generally, EPA's updated information on stationary RICE NOx emissions and control technologies concludes, for lean-burn engines, an emission rate of 2.0 g/bhp-hr is achievable for "new engines and most engines retrofitted with LEC technology."[702] Emissions reductions to meet a controlled NOx rate of 2 g/hp-hr, based on a baseline emission rate that is reflective of the units' allowable emission rate, represents an 88% reduction in NOx emissions. Revising Transwestern's cost effectiveness analyses to reflect higher baseline emission levels that are more in line with recent NMED actual emissions data, results in more favorable cost effectiveness of these controls, as shown in the table below. This revised analysis assumes baseline emissions that are reflective of more recent NMED emissions data (e.g., 899.15 tons per year for units 701, 702, and 703 based on 2018-2019 actual emissions and assuming units 721 and 722 concurrently operated at permitted allowable levels during that time). These annual emissions are distributed equally across units 701, 702, and 703 since 2018-2019 operating hours are not known. The table below presents cost effectiveness assuming an 85% reduction in NOx emissions, which reflect reducing hourly allowable NOx emission rates to a level of 2.5 g/hp-hr.

Table 50. Cost Effectiveness of LEC at Uncontrolled Mountainair Compressor Station Units 701, 702, and 703 to Reduce NO_x Levels to 2.5 g/hp-hr, Based on 2018-2019 Baseline Emission Levels Evenly Distributed Across Units 701, 702, and 703

Unit	Size [hp]	Total Annualized Costs of LEC to Reduce NOx to 2.5 g/hp-hr [2019$]	NOx Removed, tpy	Cost Effectiveness of LEC [2019$], $/ton
701	4,500	$342,000*	255	$1,341/ton
702	4,500	$342,000*	255	$1,341/ton
703	4,500	$342,000*	255	$1,341/ton

*Quote from Cooper Machinery Services 10/17/19

Note, if units 701, 702, and 703 operate with the same distribution as in 2016 (i.e., with unit 701 operating roughly 15% of the time, unit 702 operating 35% of the time, and unit 703 operating 50% of the time), the cost effectiveness would range from $900–$3,000/ton. And the cost effectiveness of LEC controls would be even more favorable, under any operating scenario, if LEC at these units were able to meet controlled emission rates below 2.5 g/hp-hr, which, as discussed earlier, has been demonstrated for other LEC retrofits for similar engines. NMED should request that Transwestern research other available retrofit options from additional

[701] *See* EPA 1993 Alternative Control Techniques Document for RICE at 5-82 and 5-83.
[702] *Id.* at 4-12.

vendors that may be able to guarantee NOx emission rates less than 2.5 g/hp-hr for these engines.

3. Use of SCR

Transwestern also evaluated SCR as a control for the four-stroke lean burn engines at Mountainair Compressor Station (Units 701, 702, and 703). The company did identify concerns with applicability of SCR to the two-stroke lean burn units including reagent injection control, exhaust temperature requirements, variations in the exhaust NO/NO_2 ratio, and engine oil carryover harming the SCR catalyst.[703] In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[704]

Irrespective of the company's concerns with applicability of SCR to the lean burn engines, Transwestern did conduct a cost effectiveness evaluation for SCR at Units 701, 702, and 703 assuming a target NOx emission rate of 0.060 to 1.02 g/hp-hr which purported reflects 90% reduction from current NOx emission levels.[705] Specifically, the company estimated the cost effectiveness of SCR at Unit 701 as $6,596/ton, at Unit 702 as $2,114/ton, and at Unit 703 as $1,372/ton.[706] The company's analyses show that SCR is more cost effective than LEC. Yet, these cost effectiveness values are in error and true cost effectiveness of SCR would be even lower, as discussed below.

One reason the cost effectiveness values are likely lower is because Transwestern relied on 2016 emissions as baseline emissions, but 2016 emissions were much lower than more recent years' emissions as discussed earlier.

Transwestern appears to have used a 2000 NESCAUM Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines to estimate capital costs for SCR.[707] Specifically, the NESCAUM formula which was based on only one case study for a RICE unit to "approximate" SCR capita costs for lean burn RICE is as follows:

$310,000 + ($72.7 x hp)[708]

[703] October 2019 Regional Haze Four-Factor Analysis for Transwestern Pipeline Company, LLC Mountainair Compressor Station at 3.
[704] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.
[705] October 2019 Regional Haze Four-Factor Analysis for Transwestern Pipeline Company, LLC Mountainair Compressor Station at Appendix A.
[706] *Id.* at Appendix B.
[707] *Id.* at 8. *See also* December 2000 NESCAUM Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines at III-30.
[708] *Id*.

This NESCAUM equation is twenty years old and is likely based on cost data from the 1990's. SCR has been implemented on numerous source types over the past twenty years, and the much wider-scale implementation and innovation in catalyst design has lowered the cost of SCR.[709] Yet, Transwestern's analysis escalated the capital costs developed with the above equation from the 2000 NESCAUM report by assuming the NESCAUM cost equation was based on 1994 costs and escalating to 2019, using the differences in the Consumer Price Index between 1994 and 2019.[710] EPA's Control Cost Manual cautions against escalating costs more than five years due to the potential for significant inaccuracies in price estimates.[711]

EPA currently has a spreadsheet available to estimate the capital and operating costs for SCR. While the spreadsheet was developed for fossil fueled fired boilers, it can be used as an estimate for SCR at other natural gas-fired sources and, in fact, has been used oil and gas companies for several four-factor analyses submitted to NMED. Transwestern included the necessary information to be able to utilize the EPA SCR cost spreadsheet to estimate SCR costs for the Units 701-703 engines. Specifically, the company provided the hourly heat input in MMBtu/hr, the inlet NOx emission rate in lb/MMBtu, the engine fuel consumption in terms of Btu/hp-hr (with which the annual fuel consumption can be estimated based on the 2016 operating hours for each unit and each unit's rated horsepower of 4500), the flue gas flow rate in actual cubic feet per minute, and the SCR inlet temperature. The elevation for the location was estimated to be 6,519 feet above sea level (the elevation of the city of Mountainair, New Mexico)

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Using the unit-specific operating hours for 2016 and assuming 90% NOx reduction across the SCR, the cost effectiveness based on EPA's SCR spreadsheet is estimated as shown in the table below. Transwestern assumed a 25-year life of SCR, which was also assumed in the SCR cost effectiveness calculation presented below which is consistent with EPA's Control Cost Manual for the expected life of SCR at an industrial unit. For reasons discussed above in this report, a 4.7% interest rate was used rather than Transwestern's assumed 5.5% interest rate. (See, e.g., Section I.A. above).

[709] See EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.

[710] October 2019 Regional Haze Four-Factor Analysis for Transwestern Pipeline Company, LLC Mountainair Compressor Station at Appendix B.

[711] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.

Table 51. Estimated Cost Effectiveness of SCR Using EPA's SCR Cost Spreadsheet and 2016 Operational Data for Units 701, 702, and 703 at Mountainair Compressor Station No. 7 (25-Year Life, 4.7% Interest Rate), 2018 $

Unit Number	Capital Cost	Operations and Maintenance Costs	Total Annual Costs	NOx Reduced from 2016 Emissions, tpy	Cost Effectiveness
701	$1,996,770	$22,760	$162,886	41	$3,989/ton
702	$1,996,397	$36,662	$176,761	137	$1,286/ton
703	$1,886,138	$44,591	$177,098	208	$850/ton

In comparison, Transwestern's SCR cost estimates are much higher. The table below provides the company's SCR cost estimates for comparison to Table 51 above.

Table 52. Transwestern's Cost Effectiveness of SCR for Units 701, 702, and 703 at Mountainair Compressor Station No. 7 (25-Year Life, 5.5% Interest Rate), 2019 $[712]

Unit Number	Capital Cost	Operations and Maintenance Costs	Total Annual Costs	NOx Reduced from 2016 Emissions, tpy	Cost Effectiveness
701	$1,100,282	$225,152	$269,152	40.81	$6,596/ton
702	$1,100,282	$246,513	$290,525	137.46	$2,114/ton
703	$1,100,282	$241,474	$285,485	208.14	$1,372/ton

Interestingly, EPA's SCR cost spreadsheet estimates a much higher capital cost than Transwestern's escalation of NESCAUM's capital cost equation for RICE units. But what makes most of the differences in the cost estimates is Transwestern's operations and maintenance costs. A review of the company's cost data sheet found two significant errors that lead to the overstatement of operations and maintenance costs. First, an error was made in the calculation of catalyst volume by Transwestern, due to an error in the formula used for the NOx efficiency adjustment factor η_{adj}. The formula for η_{adj} in EPA's Control Cost Manual chapter for SCR is:

$$\eta_{adj} = 0.2869 + (1.058 \underline{\mathbf{x}} \eta_{NOx})$$ [713]

However, Transwestern used the formula

$$\eta_{adj} = 0.2869 + (1.058 \mathbf{+} \eta_{NOx})$$ [714]

[712] October 2019 Regional Haze Four-Factor Analysis for Mountainair Compressor Station No. 7, Appendix A (pdf page 12 of report).
[713] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, at pdf page 61 (Equation 2.23).
[714] October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9, Appendix A (pdf pages 14, 16, and 18 of report).

Transwestern's error resulted in a significant overestimate of the volume of catalyst, in which η_{adj} is a multiplier, which then resulted in an overestimate of annual catalyst replacement costs.

In addition, Transwestern assumed 8,760 hours per year of operation in determining annual operations and maintenance costs which significantly overstated the costs of reagent, catalyst replacement, and labor.[715]

With these deficiencies in Transwestern's cost analysis along with its use of 2016 emissions to define the NOx emissions reduced with SCR, Transwestern's cost effectiveness values for SCR are greatly overstated. While the increased hours of operation would mean increased operational costs, the capital cost of SCR would remain the same. And the annual reduction in NOx emissions would be much greater (i.e., 90% control from 2018-2018 average NOx emissions versus 90% control from the much lower 2016 NOx emissions). Thus, with more recent NOx emissions used as baseline, SCR will be even more cost effective than shown above.

In summary, SCR is a more cost effective NOx control for the Units 701, 702, and 703 compared to LEC, which Transwestern estimated would have a cost effectiveness of $1,961/ton to $13,002/ton.[716] However, if more recent emissions data are used, the cost effectiveness of LEC would also be much lower than estimated by Transwestern at $1,341/ton.

XXI. Transwestern Pipeline Company – Corona Compressor Station

The Transwestern Pipeline Company, LLC. (Transwestern) Corona Compressor Station was not a facility for which NMED requested a four-factor analysis, yet the facility has a Q/d value (based on 2014 emissions) of 5.9. The closest Class I area to the plant is the White Mountains Wilderness, which is 60 kilometers away, according to the NMED Emissions Analysis Tool. The Corona Compressor Station is located in Lincoln County. NMED has described the facility processes as follows:

> The function of the facility is to compress natural gas. This facility receives natural gas from an upstream compressor station which goes through an inlet separator. The gas is then compressed by two (2) natural gas fired RICE compressors (units 801 and 802) and is sent to the next downstream compressor station. Two Waukesha generator engines supply electrical power to the station.[717]

According to the permit, the plant includes two 2-stroke lean-burn compressor engines, two 4-stroke rich-burn RICE, and two tanks.[718]

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[715] *Id.* at pdf pages 15-18.
[716] *Id.* at pdf page 12.
[717] Title V Operating Permit P151-R3 for Corona Compressor Station at A3.
[718] *Id.* at A5.

A. Units 801 and 802: Cooper-Bessemer V-250 2-Stroke Lean-Burn Compressor Engines

Units 801 and 802 are Cooper-Bessemer V-250 2-stroke lean-burn RICE constructed in 1967 (801) and 1968 (802), each with a capacity of 5,000 hp.[719] The units each have an hourly NOx limit of 205.5 lb/hr and an annual NOx limit of 900 tpy.[720]

1. Use of Low Emission Combustion Technology

The uncontrolled allowable NOx emission rates for units 801 and 802 of 205.5 lb/hr are equivalent to 18.6 g/hp-hr for these 5,000 hp engines. NPCA's March 2020 Oil and Gas Four-Factor Report stated that a wide range of emission rates are achievable with low emission combustion (LEC) technology, with NOx emissions generally no higher than 2 g/hp-hr and often significantly lower (e.g., as low as 0.5 g/hp-hr).[721] In 2002, EPA collected data on emission rates of lean burn engines that have been retrofitted with LEC, including data from several state agencies for specific engine models.[722] Test results for eight Cooper-Bessemer V-250 engines ranged from 1.6 to 3.4 g/hp-hr, with an average controlled NOx rate of 2.9 g/hp-hr.[723] And, overall, EPA calculated the weighted average for installation of LEC technology retrofit on all of the large IC engines in the dataset to be 2.9 g/bhp-hr.[724] At this controlled emission rate, NOx emissions reductions for units 801 and 802 would be 84%. These emissions reductions could prevent up to 1,500 tons per year of NOx emissions from these two units, combined, for operation at permitted annual levels. NMED should request a four-factor analysis for these units to evaluate the cost effectiveness of controlling NOx emissions from these units with LEC to 2.9 g/hp-hr.

2. Use of SCR

SCR can be a very effective method for reducing NOx emissions and the technology is often retrofit to constricted industrial sites. In a May 21, 2020 report, many of the claims made by New Mexico oil and gas companies regarding the retrofit issues with SCR on lean burn engines were addressed. That report is incorporated herein by reference and we refer the reader to that report for justification for considering SCR at lean burn engines to significantly reduce NOx emissions.[725]

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[719] *Id.*
[720] *Id*. at A7.
[721] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 28.
[722] *See* EPA Stationary Reciprocating Internal Combustion Engines Technical Support Document for NOx SIP Call (October 2003) at 15, *available at:* http://www.valleyair.org/workshops/postings/2011/8-18-11-rule4702/R4702%20APPF.pdf.
[723] *Id.* Table 4.
[724] *Id.* at 25.
[725] *See* Stamper, Victoria and Megan Williams, Review of Claims Made by New Mexico Oil and Gas Companies Regarding Applicability of Selective Catalytic Reduction (SCR) to Lean Burn Engines, May 21, 2020, provided to NMED via a May 22, 2020 letter from NPCA.

If LEC is not a viable or cost effective control for lean burn engines, SCR could possibly be a more cost effective control. That is what Transwestern Pipeline found in its four-factor analysis for its two Cooper-Bessemer LSV-16G four-stroke lean-burn engines at the Roswell Compressor No. 9.[726] In Section XIX.A.2. of this report, we provided a revised cost effectiveness analysis of SCR using the SCR cost spreadsheet EPA provides with its Control Cost Manual[727] that showed SCR would be even more cost effective than reflected in Transwestern Pipeline's four-factor submittal, in the range of $2,400/ton to $2,800/ton at engines that, based on 2016 data, operate at 11%-41% of available hours. In addition, the costs of SCR could be reduced if there were options for a shared SCR system between engines. For all of these reasons, NMED should consider SCR as a potentially viable control option for lean burn engines in a company's analysis of available controls to achieve reasonable progress towards the national visibility goal.

B. Units 821 and 822: Waukesha F3520GU 4-Stroke Rich-Burn RICE

Units 821 and 822 are Waukesha F3520GU 4-stroke rich-burn RICE constructed in 1967, each with a capacity of 418 hp.[728] The units each have an hourly NOx limit of 18.5 lb/hr and a combined annual NOx limit of 83.4 tpy.[729]

1. Use of Non-Selective Catalytic Reduction

The uncontrolled allowable NOx emission rates for units 821 and 822 of 18.5 lb/hr are equivalent to 20.1 g/hp-hr for these 418 hp engines. NPCA's March 2020 Oil and Gas Four-Factor Report provides an analysis of the cost effectiveness of NSCR to reduce NOx emissions from rich-burn RICE by 94%.[730] This cost analysis is laid out below, as applied to these two specific units at the Corona Compressor Station.

EPA describes NSCR and potential controlled emission rates in its Alternative Control Techniques document for RICE:

> Catalyst vendors quote NOx emission reduction efficiencies of 90 to 98 percent. Based on an average uncontrolled NOx emission level of 15.8 g/hp-hr (1,060 ppmv), the expected range of controlled NOx emissions is from 0.3 to 1.6 g/hp-hr….[731,732]

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[726] *See* October 2019 Regional Haze Four-Factor Analysis for Roswell Compressor Station No. 9 at 2.
[727] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[728] *Id.* at A5.
[729] *Id*. at A7.
[730] March 6, 2020 NPCA Oil and Gas Four-Factor Report at 17-20 and Table 7 at 26.
[731] EPA 1993 Alternative Control Techniques Document for RICE at 2-10 to 2-11.
[732] Note, employing NSCR to reduce NOx emissions from EPA's uncontrolled emission rate of 15.8 g/bhp-hr to 1.0 g/bhp-hr corresponds to a NOx emission reduction efficiency of 94%. This control efficiency is used in the analysis presented here as a reasonable achievable emission rate but certainly not the lowest possibility.

A cost effectiveness analysis of NSCR was performed in 2010 for EPA, to help determine national impacts associated with EPA's final rule for Reciprocating Internal Combustion Engine National Emission Standards for Hazardous Air Pollutants (RICE NESHAP).[733] The analysis, performed by E^C/R Incorporated, was based on 2009 cost data for retrofitting NSCR on existing 4SRB engines from industry groups, vendors, and manufacturers of RICE control technology. E^C/R Incorporated performed a linear regression analysis[734] on the data set to determine the following linear equation for annual cost, which includes annual operating and maintenance costs plus annualized capital costs based on a 7% interest rate and 10-year life of controls:

NSCR Annual Cost = $4.77 x (hp) + $5,697 (2009$)

The capital cost equation for retrofitting an air-to-fuel ratio controller (AFRC) and NSCR on a 4SRB engine was determined by E^C/R Incorporated to be, as follows:

NSCR Capital Cost = $24.9 x (hp) + $13,118 (2009$)

These relationships are derived from a data set that includes engines ranging in size from 50–3,000 hp.

The E^C/R document does not explain why it assumed a 10-year life of controls for estimating the annualized capital costs. The life of a RICE unit is generally much longer than ten years, and is often at least thirty years.[735] The assumed 10-year life was not based on the catalyst replacement timeframe, because the E^C/R operating costs took into account the cost for replacing the catalyst every three years, as well as replacing the thermocouple every 7.5 years, the crankcase filters every three months, the oxygen sensor on a quarterly basis, and rotating the catalyst for cleaning annually.[736] Thus, the assumed 10-year life of an NSCR system seems arbitrary. In cost analyses done in 2000 for EPA, an equipment life of NSCR of fifteen years was assumed.[737] The state of Colorado also recently assumed a 15-year life of NSCR for RICE

[733] Memo from E^C/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010), *available at*: https://www.epa.gov/sites/production/files/2014-02/documents/5_2011_ctrlcostmemo_exist_si.pdf.

[734] *Id.* The report notes that the linear equation has a correlation coefficient (R) of 0.7987, concluding that it "shows an acceptable representation of cost data."

[735] *See, e.g.*, EPRI, 20 Power Companies Examine the Role of Reciprocating Internal Combustion Engines for the Grid, *available at*: https://eprijournal.com/start-your-engines/. The authors also note that, in reviewing permits for gas processing facilities and compressor stations in New Mexico, it is not uncommon to have engines that were constructed from the 1950's to 1970's still operating at such facilities.

[736] Memo from E^C/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010), at 4 and at 11, 13, and 15.

[737] *See* August 11, 2000, E.H. Pechan & Associates, Inc., NOx Emissions Control Costs for Stationary Reciprocating Internal Combustion Engines in the NOx SIP Call States, at 5 and at A-2, *available at*: https://www3.epa.gov/ttn/ecas/regdata/cost/pechan8-11.pdf. *See also* EPA, Regulatory Impact Analysis for the NOx SIP Call, IP, and Section 126 Petitions, September 1998, at 5-5 (Table 5-3).

units.[738] Given that EPA assumed a selective catalytic reduction (SCR) system at an industrial fossil fuel-fired boiler has a life of 20-25 years,[739] it seems very likely that NSCR would have a useful life of at least fifteen years if not longer. For the purpose of the NSCR cost analyses presented here, a 15-year life of the NSCR system was assumed.

In addition, a lower interest rate than 7% is assumed in determining annualized costs of controls for this report. As discussed earlier, a 4.7% interest rate seems like the highest bank prime interest rate (and it will likely be lower) that could be in place in the next year when NMED adopts reasonable progress controls.

The table below shows the cost effectiveness of NSCR and an AFRC achieving 94% NOx reduction efficiency and operating at 2,000 hours per year and 8,000 hours per year, based on these cost equations from EPA's 2010 RICE NESHAP, adjusted to reflect a 4.7% interest rate and 15-year life of controls.

Note that lower NOx emission limits may be possible that reflect a higher NOx removal efficiency than the 94% assumed in the table below and the costs of employing NSCR to meet these lower limits will be even more cost effective than what is shown here.

Table 53. Cost Effectiveness to Reduce NOx Emissions from 4SRB RICE with NSCR and an AFRC, Based on EPA RICE NESHAP Cost Equations for Existing Stationary RICE[740]

UNIT	SIZE, hp	ANNUALIZED COSTS OF NSCR AND AFRC, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 2,000 HR/YR, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 8,000 HR/YR, 2009$
801	418	$6,544	$499/ton	$125/ton
802	418	$6,544	$499/ton	$125/ton

We did not escalate these costs to 2019 dollars. The Chemical Engineering Plant Cost Index (CEPCI) has been used extensively by EPA for escalating costs, but EPA states that using the CEPCI indices to escalate costs over a period longer than five years can lead to inaccuracies in

[738] *See* Colorado Department of Public Health and Environment, Air Pollution Control Division, Reasonable Progress Evaluation for RICE Source Category, circa 2008 [hereinafter referred to as "CDPHE RP for RICE"], at 8, *available at*: https://www.colorado.gov/pacific/sites/default/files/AP_PO_Reciprocating-Internal-Combustion-Engine-RICE-engines_0.pdf.

[739] *See* EPA, Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, at pdf page 80, *available at*: https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf.

[740] *See* Memo from E^{C}/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010). Annualized costs of control were calculated using a capital recovery factor of 0.099626 (assuming a 15-year life of controls and a 4.7% interest rate). Uncontrolled NOx emissions are based on EPA's 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032) and a 94% NOx removal efficiency.

price estimation.[741] Further, the prices of an air pollution control do not always rise at the same level as price inflation rates. As an air pollution control is required to be implemented more frequently over time, the costs of the air pollution control often decrease due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc. However, even today's costs for NSCR are assumed to be very cost effective given that the cost effectiveness based on 2009$ is on the order of $100/ton.

XXII. Durango Midstream - Empire Abo Gas Plant

The Empire Abo Gas Plant is a natural gas processing and gas sweetening plan located in Eddy County, New Mexico, operated by Durango Midstream. NMED did not request a four-factor analysis for this facility, but the source does have a Q/d value of 24.2 based on 2014 emissions and it is 68.9 kilometers from Carlsbad Caverns National Park according to NMED's Emission Data Analysis Tool. The plant is permitted to operate under two operating scenarios: 1) a gas sweetening and processing plant, and 2) a compressor station that receives gas at low pressure and routes it to the Maljamar Gas Plant for processing.[742] A review of data on NMED's Emissions Analysis Tool shows that the plant has varying emissions, with the last three years (2017-2019) being much lower emissions than in the past. For the 2016 year that most facilities used as a baseline, the plant emitted 271.1 tons of SO2. However, currently, the plant emitted 72 tons in 2019 and only 19 tons of SO2. In the 2012 to 2015 timeframe, the plant had about 200 tpy of NOx emissions and approximately 450-850 tpy of SO2 emissions. The state should request information from Durango Midstream as to the planned operation of the plant (whether it will be primarily as a gas sweetening plant or a compressor station) in 2028 to determine which sources to focus on for control.

Of all of the emission limits identified in the Title V permit, the SRU/Incinerator is allowed the highest level of emissions of 565 tpy.[743] Based on the discussion in Section XXIII below, NMED should thus require the company to evaluate an AGI well and/or an acid gas scrubber to add after the tail gas incinerator to remove SO2 when the SRU is down for maintenance.

XXIII. Comments on Pollution Control Evaluations for Amine Units/Acid Gas Flares at Gas Sweetening Plants

NMED requested four-factor analyses of controls for several amine units at New Mexico gas processing plants. Amine treating units are used to remove hydrogen sulfide (H2S) and carbon dioxide (CO2) from natural gas. Plants that remove H2S are referred to as gas sweetening plants. Amines such as Monoethanolamine (MEA), Diglycolamine (DGA), Diethanolamine (DEA) and Methyldiethanolamine (MDEA) can form salts with H2S and CO2 in an aqueous solution.

Targa's four-factor submittal for the Saunders gas plant describes and amine unit as follows:

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[741] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.
[742] 6/30/2017 Title V Permit No. P146-R3 for Empire Abo Gas Plant.
[743] *Id.*at A11.

> An amine treating unit operates by feeding the inlet gas stream into the bottom of a contactor and simultaneously feeding a lean amine solution at the top of the contactor. The two streams interact in counter flow, resulting in CO2 and H2S being stripped from the natural gas stream. The lean amine solution must be kept at a higher temperature than the gas feeding into the contactor, or condensation of heavier hydrocarbons could occur. Trays or packing in the contactor provide a place for the lean amine solution to interact with the inlet gas stream. The natural gas leaving the contactor will be "sweet gas."
>
> The rich amine leaving the contactor is usually sent to a flash tank which reduces the pressure of the stream and causes dissolved hydrocarbons to flash off. The rich amine will then pass through a heat exchanger and enter a solvent regenerator. The heated vapor generated at the bottom of the regenerator flows upward through the trays or packing where it comes in contact with the rich amine and removes the acid gases from the amine. The lean amine is then cooled and reenters the first contactor to start the process over. The acid gas that is dissolved in the vapor is then sent to a control device such as a sulfur recover unit (SRU) with a tail gas incinerator, a flare, or an acid gas injection (AGI) well.

November 2019 Four-Factor Analysis for Saunders Gas Plant at 2-8 to 2-9.

The acid gas exiting the amine unit is essentially composed of H2S and CO2. While the percentage of H2S and CO2 can vary depending on the sulfur content of the natural gas, as one example, a gas amine unit in Texas in the Permian Basin is composed of approximately 45% H2H and 54% CO2.[744] According to EPA's AP-42 Emission Factor documentation, emissions from gas sweetening units only result when gas is flared or incinerated and the major pollutant of concern from such flaring or incineration is SO2.[745] When the acid gas stream is flared rather than injected into the geologic strata or controlled with an SRU, all or most of the H2S is converted to SO2. While flaring may be a control for H2S in the acid gas stream, it is a cause of SO2 emissions and does not control SO2.

The typical controls for amine units are acid gas injection (AGI) well or a sulfur recovery unit (SRU). An AGI well should result in no emissions because the acid gas stream is injected into the geologic strata. However, if there are any malfunctions in the equipment that pumps the acid gas stream into the AGI, then air emissions can result. An SRU converts hydrogen sulfide to element sulfur. The most commonly applied method is the Claus method, which can typically recover 95-97% of the hydrogen sulfide feed stream.[746] According to EPA, older SRUs or very

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[744] *See* Oil and Gas Docket No. 08-0289658, Application of James Lake Midstream, LLC, available for download at https://www.rrc.state.tx.us/hearings/dockets/oil-gas-proposals-for-decision-and-orders/index-for-336/.
[745] EPA, AP-42, Section 5.3 Natural Gas Processing at 5.3-3.
[746] EPA, AP-42, Sulfur Recovery at 8.13-1.

small Claus plants producing less than 22 tons of sulfur per day have varying sulfur recovery efficiencies.[747] The following table lists those amine units for which NMED requested four-factor analyses for the control of SO2.

Table 54. List of Facility Amine Units (or Acid Gas Flares) For Which NMED Requested Four-Factor Analysis of Controls and Potential to Emit (PTE) SO2 as Reported in Company Analysis

Facility	Amine Unit	Existing Controls	PTE SO2 tpy	PTE SO2 lb/hr
Jal No. 3	Unit 9S (Thermal Oxidizer)	SRU and AGI well	1,205.9	275.3
DCP-Eunice Gas Plant	Unit 31	SRU	257.2	9,368.2
Targa-Eunice Gas Plant	Unit AM-01/F-01	AGI well	776.5	5,176.6
Targa-Monument Gas Plant	Unit AM-01/F-03	AGI well	872.6	5,817.5
Targa – Saunders Gas Plant	Unit A-01/I-01	SRU with tail gas incinerator	1,397.0	316.7
DCP-Artesia Gas Plant	Amine-C Unit 23 (Acid Gas Flare)	AGI well	328.2	4918.4
Davis Gas Processing - Denton Gas Plant	Unit 005 (amine regeneration still and reboiler) and Unit 007 (acid gas flare)	None	1,195.9	312.5
Oxy-Indian Basin Gas Plant	Unit AMINE -1 & SELEXOL	AGI	Not indicated	Not Indicated

It must be noted that there are facilities listed in the above table that did not specifically list amine units but that otherwise did list startup, shutdown, and maintenance (SSM) emissions as triggering the need for a four-factor analysis due to SO2 emissions. For those facilities listed in the above table (DCP Eunice Gas Plant and DCP Artesia Gas Plant), the units have gas sweetening plants and the SO2 emissions from SSM are from flaring of the acid gases. Yet, those companies' four-factor analyses claimed they did not need to evaluate controls for SSM emissions that occur during "non-steady state" operations.[748] Flaring of the acid gas stream at units with amine units appear to, unfortunately, be part of the normal operations of the unit even though due to SSM, and there are control options available to reduce SO2 emissions from flaring – by reducing flaring via redundant acid gas steam control options (second AGI well, or

[747] *Id.* at 8.13-3.

[748] *See*, e.g., November 2019 Four-Factor Analysis for DCP Eunice Gas Plant at 1-2 and November 2019 Four-Factor Analysis for DCP Artesia Gas Plant at 1-2.

redundant compressor at AGI well, or SRU plus AGI well) or by replacing a flare with an incinerator and acid gas scrubber to be used when the primary acid gas control for the amine unit is not functioning. Thus, NMED must not allow facilities with significant SO2 emissions due to SSM to be exempt from a four-factor analysis of controls.

The following provides a discussion of controls for SO2 emissions at gas sweetening plants in the context of reviewing and commenting on the four-factor submittals for the facilities listed in the above table.

A. Amine Units with No Acid Gas Controls – Denton Gas Plant

There is one amine unit listed in the above table which apparently has no H2S controls – the Davis Gas Processing Denton Gas Plant. Although the Denton Gas Plant used 2017-2018 SO2 emissions as baseline emissions for its cost effectiveness analysis, the plant's two-year average SO2 emissions have varied from 713.00 tpy (2017-2018 average) to 1,061.27 tpy over the past ten years.[749] Davis Gas Processing states that the sulfur recovery process (both the Claus process and another processed called LO-CAT) were eliminated from further consideration because of concerns of the level of control achievable with variable flowrates and H2S concentrations, which the company claims are common at Denton, and apparently because of the low throughput rate that would apply to an SRU at the Denton amine unit.[750] While a properly designed, operated, and maintained acid gas injection well would achieve a higher level of SO2 control (SO2 removal efficiency should be 100% with an AGI well), we note that NMED has requested some companies to analyze installing an AGI well in addition to having a sulfur recovery unit.[751] Such duplicative controls should be considered, even for units with AGI wells. Although an AGI well in theory should provide 100% control of SO2, problems with the equipment to compress and pump the acid gas steam into the AGI well can occur – or sometimes even with the AGI well. For example, Targa explained that its Monument AGI well "failed an OCD required pressure test on July 27, 2016" and the well had to be shut down August 8th and ultimately was abandoned, resulting in significant flaring of acid gas until the new well became operational in March 2017.[752] This flaring resulted in approximately 2,000 tons of SO2[753] from a pollution control that should have 100% SO2 reduction efficiency. While this AGI well malfunction may have been unique, there clearly are also problems with AGI compressors because other New Mexico companies have installed, or are in the process of installing, redundant compressors.[754] Yet, redundant compressors are not necessarily enough to prevent significant SO2 emissions from flaring that may occur during upsets or maintenance. NMED should ask each company with gas sweetening plants, including the Denton Gas Plant, to evaluate the cost of redundant SO2 pollution controls. One option is to install an SRU if the

[749] November 2019 Denton Gas Plant Four-Factor Analysis at 2-2.
[750] *Id.* at 2-4.
[751] *See* Targa's February 2020 Four-Factor Addendum for the Eunice Gas Plant at pdf page 10.
[752] *Id.*at pdf page 9.
[753] *Id.*
[754] *Id.* at pdf page 10. Targa states that it installed redundant compression at the Monument AGI well as a result of an AQB enforcement case. Targa also installed redundant compression at the Eunice Gas Processing Plant.

facility already has an AGI well, to be used when the AGI well cannot be used for control. Another option is to have the gas routed to an incinerator with an add-on acid gas scrubber, when the AGI well is not functioning.[755] For those facilities that have SRUs to control SO2 from amine units or that have no SO2 controls such as the Denton Gas Plant, adding an AGI well as a duplicative control should be evaluated first.

The four-factor analysis for the Denton Gas Plant evaluated the costs of installing an AGI well. While the Denton analysis used a 5.25% interest rate and a 20-year life as well as the lowest 2-year baseline of all of the past 10 years of SO2 emissions, the company's cost effectiveness analysis shows that an AGI well would be quite cost effective at $1,014/ton of SO2 removed.[756] Davis Gas Processing likely overstated the capital costs of an AGI well, by adding 25% to the purchased equipment costs as well as using EPA's Control Cost Manual's percentage of purchased equipment costs for foundations and supports, handling and erection, etc.[757] As the company notes in its four-factor analysis, the use of AGI for the disposal of acid gas "is becoming increasingly common…"[758] Thus, rather than adding a 25% contingency factor to the purchased equipment cost and then adding EPA's Control Cost Manual estimates (which are a percentage of the purchased equipment costs) for installation of an AGI, the company could have obtained a reliable estimate of the cost of AGI well installation. With respect to operating expenses, David Gas Processing's analysis assumed a cost per kW hour of $0.11 which appears to be the cost for residential service in New Mexico.[759] The electricity cost for an industrial user is generally much lower than a residential user. EPA estimates the cost for electricity in its SCR cost spreadsheet of $0.0676/kWh. A web search for average electricity cost in New Mexico for industrial use shows a cost of $0.0583/kWh.[760] Thus, annual electricity costs for the electric compressors for an AGI well in New Mexico should be in the range of $41,893 to $48,575 rather than the $79,043 assumed for the Denton Gas Plant. Further, this cost reflects electricity use when the compressors are used at maximum capacity for all hours of the year, so this is a worst case annual operating cost. The company's assumed cost for electricity has a significant impact on the cost effectiveness of an AGI well. When just the cost for electricity is revised to be $0.0583/kWh, the cost effectiveness of an AGI well at the Denton Gas Plant reduced from $1,014/ton to $663/ton. If the interest rate is lowered to a more reasonable 4.7% for the reasons discussed in this report and the life of an AGI well is increased to 25 years which seems reasonable given the life of gas sweetening plants like Denton, the cost effectiveness of an AGI well further reduces to $574/ton. Moreover, if one removes the 25% contingency factor that Davis Gas Processing applied to its estimate of equipment costs, the cost effectiveness of AGI to reduce SO2 would be $481/ton. Clearly, installation of an AGI well is very cost effective for the Denton Gas Plant.

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[755] *See* March 2020 NPCA Oil and Gas Four-Factor Report at 148-154.
[756] November 2019 Denton Gas Plant Four-Factor Analysis at 3-4.
[757] *Id.*
[758] *Id.* at 2-5.
[759] *See*, e.g., https://www.electricitylocal.com/states/new-mexico/.
[760] https://www.electricitylocal.com/states/new-mexico/

B. Amine Units with SRUs – DCP Eunice Gas Plant and Targa Saunders Gas Plant

With respect to the DCP Eunice Gas Plant which has an SRU, DCP's four-factor analysis claims that the area is not suitable for an AGI well[761] despite being near to the Targa Monument Gas Plant which also has an AGI well. It appears that the plants are roughly 10 miles apart. NMED should request more information from DCP as to why it claims an AGI well is not viable for its Eunice Gas Plant. Not only could this provide more information to enable NMED to thoroughly consider the Targa Monument Plant's SO2 controls for its amine plant, but it is needed to justify DCP's claims that an AGI well is not feasible for its location especially given how cost effective an AGI well can be based on the revised Denton Gas Plant analysis discussed above. DCP states that AGI wells typically include a second redundant AGI well.[762] The fact that such redundancy is required for SO2 controls when an AGI well is used for control argues for redundancy in controls when an SRU (which is not nearly as efficient in SO2 reduction as a properly operating AGI well) is used for SO2 control. Use of an incinerator with an add-on acid gas scrubber as a redundant control for those amine units with SRUs should thus be evaluated as an additional SO2 control. This could be used downstream of the SRU to improve SO2 removal efficiency when the SRU is operating and could also be used when the SRU is down for maintenance or upsets. These types of duplicative control have been used in oil refineries and thus are a viable control option for a natural gas processing plant as well.[763] NMED should thus require DCP to evaluate this control option. In addition, NMED should ask DCP to report on its SO2 removal efficiency of its current SRU and to quantify its actual SO2 emissions from flaring the acid gas stream when the SRU is down for maintenance or upsets. As part of its four-factor analysis, NMED must evaluate the level of SO2 control currently being achieved at the gas sweetening plant and ensure that all available options for improving that level of control are evaluated. The Targa Saunders Gas Plant utilizes a "Select-Tox Single State Claus bed with a tail gas incinerator" as a control for the amine unit, with an acid gas flare when the SRU is down for maintenance.[764] Targa considered an AGI well, but claimed it could not install an AGI well without plugging/cementing some of the numerous other wells in the area because acid gas could vent from any unplugged wells.[765] NMED should request more information on the documentation collected by Targa to support this claim. Targa did not evaluate any other controls to reduce SO2 emissions from its amine unit after finding an AGI well was not feasible for the Saunders plant.[766] NMED should require Targa to evaluate the option of adding an acid gas scrubber to its tail gas incinerator and to operate the incinerator and scrubber when the SRU is not available due to maintenance or upsets. This would enable the continued control of SO2 even during SRU downtime, rather than flaring which does not control SO2 emissions at all. In addition, NMED should ask DCP to report on its SO2 removal efficiency of its current SRU and

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[761] November 2019 Four-Factor Analysis for DCP Operating Company's Eunice Gas Plant at 2-8 to 2-9.
[762] *Id.*
[763] *See*, e.g., July 2006, Meyer, Steven F., Christina Kulczycki, Ed Juno, and Nick Watts, Improving Sulphur recovery units, Digited Refining, available at https://www.digitalrefining.com/article/1000244/improving-sulphur-recovery-units#.XvJCRudME2w.
[764] November 2019 Four-Factor Analysis for Targa Saunders Gas Plant at 2-9.
[765] *Id.* at 2-10.
[766] *Id.* at 3-3.

to quantify its actual SO2 emissions from flaring the acid gas stream when the SRU is down for maintenance or upsets. As part of its four-factor analysis, DCP must evaluate the level of SO2 control currently being achieved at the gas sweetening plant and ensure that all available options for improving that level of control are evaluated.

C. Amine Units with AGI Wells – Targa Eunice Gas Plant, Targa Monument Gas Plant, DCP Artesia Gas Plant, and Oxy Indian Basin Gas Plant

As indicated above, the Targa Monument Gas Plant flared its acid gas stream for several months in 2016 -2017 due to a failed AGI well after five years of service.[767] This facility provides a pertinent example of how - even an amine unit controlled by an AGI well, which should theoretically eliminate 100% of the potential SO2 emissions - acid gas injection wells need backup and/or redundancy to ensure control of SO2. Indeed, NMED must require all amine plants with AGI wells in the table above to consider duplicative controls for removal of sulfur from the acid gas stream or prevention of SO2 emissions from flaring. Options to consider are 1) a duplicative AGI well, 2) an incinerator and add-on acid gas scrubber or an SRU for when the acid gas stream cannot be routed to the AGI well, and 3) duplicative equipment for ensuring the acid gas is continually injected into the acid gas well, such as a redundant electric compressor. The four-factor analysis submitted by Targa for the Eunice Gas Plant claims the AGI well is in the process of having redundant electric compression added to the AGI well to further reduce SO2 emissions during SSM.[768] Targa did not evaluate any other controls. Similarly, Targa stated that it is adding redundant electric compression to the Monument AGI well, and the company did not evaluate any other controls for its amine plant.[769] While having redundant compression will help to ensure that the acid gas stream is not flared due to the AGI well compressor malfunctioning or being down for maintenance, NMED should ask Targa to evaluate the costs of adding an SRU or adding an incinerator and acid gas scrubber for further redundancy in its SO2 control systems. With respect to the Monument Gas Plant AGI well, given the statements made by DCP in its four-factor analysis for the Eunice Gas Plant that the area is not well-suited for acid gas injection and given the Monument plant's proximity to the DCP Eunice Gas Plant, NMED must determine if the failure of the Monument AGI well is due to any of the reasons that DCP indicated in its Eunice Gas Plant four-factor analysis for an AGI well not being viable in the region. Further, NMED should collect and present data on the last five years of how much SO2 was emitted due to flaring of the acid gas stream at Monument due to upsets at the AGI well's compressors or other causes of flaring of the acid gas stream. Given the failure of the Monument AGI well after five years and the resulting 2,000 tons of SO2 emitted, it seems that redundant controls such as an SRU or an incinerator with acid gas scrubber must be considered as a duplicative SO2 control for the amine unit at the Monument Gas Plant. NMED should also require an evaluation of such controls for the Targa Eunice Gas Plant.

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[767] *See* Targa's February 2020 Four-Factor Addendum for the Eunice Gas Plant at pdf page 9.
[768] November 2019 Four-Factor Submittal for Targa Eunice Gas Plant at 2-6.
[769] November 2019 Four-Factor Submittal for Targa Monument Gas Plant at 2-1.

In the Oxy Indian Basin Gas Plant four-factor submittal, Oxy only evaluated one control – a redundant compressor for the AGI.[770] Oxy's submittal indicated a cost effectiveness of $27,600/ton of SO2 reduced due to an estimated cost for electric compression of $11 million.[771] The company assumed baseline emissions from 2016 of NMED of 41.92 tpy and assumed a redundant compressor would reduce those emissions by 90%. NMED should ensure that the company is using realistic baseline emissions due to flaring of the acid gas stream. If 2016 was an exceptionally good year (not much flaring), but prior years had much higher emissions, cost effectiveness should be based on a longer term average of emissions. If baseline emissions were 200 tpy of SO2 from flaring, and with a more appropriate interest rate and lifetime of electric compressor of 4.7% and 25 years (instead of 5.50% and 20 years), the cost effectiveness of a redundant compressor would reduce to $4,873/ton. If the plant emitted 500 tpy, the cost effectiveness would be about $2,000/ton. Thus, it is imperative that NMED ensure that the company uses a realistic SO2 baseline for evaluating redundant controls such as duplicative compressor for its acid gas injection well. NMED did ask Oxy to consider adding a second control to its AGI system to reduce flaring emissions, such as the LO-CAT sulfur recovery technology.[772] The company indicates that it had an SRU that has been shut down due to poor reliability.[773] Given that the SRU already exists on site, NMED should ask the company to evaluate the cost for bringing the SRU back online to use only as a backup to the AGI well. That could be a very cost effective way to ensure redundancy in the SO2 removal systems at the Indian Basin Gas Plant.

DCP did not evaluate any controls for its amine plant at the Artesia Gas Plant. The company's four-factor analysis only listed emissions from flaring and stated that, based on NMED's September 23, 2019 guidance, it did not need to evaluate controls from flaring.[774] Yet, it listed acid gas flaring (Unit 23) as a significant source of SO2 emissions.[775] A review of the Title V permit for the facility shows that the facility has an amine plant and an AGI well.[776] NMED must request that the company provide information on its actual SO2 emissions from flaring the acid gas stream from its amine unit. Further, NMED must request DCP to evaluate duplicative controls and/or redundant AGI well compression.

Moreover, as part of evaluating SO2 control options for any gas processing plant, NMED should collect information on the time periods, causes, and SO2 emissions of acid gas stream flaring at the plant to determine if additional maintenance requirements should be imposed with reporting and recordkeeping to NMED.

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[770] November 2019 Four-Factor Analysis for Indian Basin Gas Plant at 2-5, 3-2, and Appendix B.
[771] *Id.* at Appendix B.
[772] February 2020 Four-Factor Addendum for Oxy Indian Basin Gas Plant at pdf page 2.
[773] *Id.*
[774] November 2019 Four-Factor Submittal for DCP Artesia Gas Plant at 1-2.
[775] *Id.*
[776] 6/27/17 Title V Permit No. P095-R3 for DCP Artesia Gas Plant at A8.

D. Units with SRU and AGI Well – Jal No. 3

The four-factor analysis for the Jal No. 3 amine plant states that the acid gas from its amine units is sent to a sulfur recovery unit which scrubs the H2S at 92% efficiency and that the leftover H2S from the SRU is sent to the thermal oxidizer to be combusted.[777] During downtime of the SRU and/or thermal oxidizer, the acid gas is sent to the AGI wells, and during AGI well downtime, the acid gas is sent to the SRU and thermal oxidizer.[778] The company's four-factor analysis states that "[t]hese existing controls are the best known technologies for controlling acid gas and, to our knowledge, there are no other technically feasible control options to further reduce SO2 emissions from the thermal oxidizer."[779] While this suite of controls does reflect the type of duplicity in controls that is necessary for addressing SO2 emissions as gas sweetening plants, it does seem that there are additional control options that the company should have considered. Despite these duplicative controls, the facility emits significant quantities of SO2. According to date on NMED's Emissions Analysis Tool, the Jal No. 3 plant emitted almost 2,000 tons of SO2 in 2016, the year NMED is apparently using as the baseline year for company four-factor analyses. While SO2 emissions have decreased since then, annual SO2 emissions have varied from 207 tons in 2017 to 1,444 tons in 2018 to 587 tons in 2019. Presumably these emissions are all from the Unit 9S thermal oxidizer, as that appears to be the primary source of SO2 emissions based on a review of the Title V permit.

Two additional control options should have been considered for the Jal No. 3 amine unit/thermal oxidizer: 1) Routing the cleaned acid gas stream from the SRU to the AGI well during normal operation of the SRU, which would improve SO2 removal efficiency from 92% to 100% (when the AGI well was operating and not down for maintenance or upset). Under this control option, the plant should continue to route the acid gas stream directly to the AGI wells during SRU downtime; or 2) Revise the configuration to inject the acid gas stream from the amine units to AGI wells, but route the acid gas stream to the SRU/thermal oxidizer during AGI well downtime to at least achieve 92% H2S removal before combusting the acid gas. It seems like either of these two options could provide for significant additional control of SO2 from the amine units at the Jal No. 3 gas plant. NMED must require ETC Texas Pipeline to evaluate these available control options at Jal No. 3 (given that the SRU and the AGI wells already exist at the facility) to control the SO2 emissions from the facility which can be quite significant despite the plant's duplicative controls.

E. Summary

In summary, because the flaring or incineration of acid gas streams from amine units at gas sweetening plants can be such a significant source of SO2, NMED must ensure a thorough evaluation of control options for such sources. NMED should not consider such sources of emissions to be non-steady state and exempt from the four-factor review of controls, because

[777] October 2019 Regional Haze Four-Factor Analysis for ETC Texas Pipeline, Ltd. Jal No. 3 Gas Plant at 7.
[778] *Id.*
[779] *Id.* at 8.

such emissions of SO2 can be very high and can be addressed through duplicative or redundant controls. NMED must also ensure that reasonable evaluations of baseline emissions are used in evaluating the cost effectiveness of controls, in that the baseline emissions must realistically depict emissions from acid gas incineration at a facility.