

Commonwealth of Pennsylvania



Technical Support Document

**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
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IV. Abbreviations and Acronyms

A/F	Air-to-Fuel
AVO	Auditory, Visual, and Olfactory Inspections
BAT	Best Available Technology
bhp	Brake Horsepower
BMP	Best Management Practices
BTEX	Benzene, Toluene, Ethylbenzene, and Xylene
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO ₂	Carbon Dioxide
CPI	Consumer Price Index
DEA	Diethanolamine
DEP	Pennsylvania Department of Environmental Protection
EGR	Exhaust Gas Recirculation
EPA	U.S. Environmental Protection Agency
g/bhp-h	Grams per Brake Horsepower-Hour
GHG	Greenhouse Gas(es)
GP	General Plan Approval/General Operating Permit
GP-5	General Plan Approval/General Operating Permit for Natural Gas Compression Stations, Processing Plants, and Transmission Stations
GP-5A	General Plan Approval/General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations
H ₂ O	Water
H ₂ S	Hydrogen Sulfide
HAP	Hazardous Air Pollutant
HCHO	Formaldehyde
GPU	Gas Production Unit
MEA	Monoethanolamine
Mcf	Thousand Cubic Feet
MMBtu	Million British Thermal Units
MMBtu/h	Million British Thermal Units per Hour
N ₂	Molecular Nitrogen
NAAQS	National Ambient Air Quality Standard
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGL	Natural Gas Liquid
NGStar	The Natural Gas Star Program
NMNEHC	Non-Methane, Non-Ethane Hydrocarbon
NO	Nitrogen Oxide
NO ₂	Nitrogen Dioxide
NO _x	Oxides of Nitrogen
NSCR	Non-Selective Catalytic Reduction
NSPS	New Source Performance Standard
OGI	Optical Gas Imaging Camera
PennDOT	Pennsylvania Department of Transportation
PM	Particulate Matter
PM _{2.5}	Particulate Matter with an Aerodynamic Diameter Less Than 2.5 Microns
PM ₁₀	Particulate Matter with an Aerodynamic Diameter Less Than 10 Microns
ppmvd	Parts Per Million, Dry, by Volume

ppmv	Parts Per Million by Volume
PRO	Partner Reported Opportunities
PTE	Potential to Emit
RBLC	RACT/BACT/LAER Clearinghouse
REC	Reduced Emission Completion
scf	Standard Cubic Feet
SCR	Selective Catalytic Reduction
SI-RICE	Spark Ignition Reciprocating Internal Combustion Engine
SO ₂	Sulfur Dioxide
SO _x	Oxides of Sulfur
THC	Total Hydrocarbons
tpy	Tons Per Year
TSD	Technical Support Document
VOC	Volatile Organic Compound

V. Executive Summary

This technical support document (TSD) was prepared by the Pennsylvania Department of Environmental Protection (Department or DEP) to include background information about the General Plan Approval and General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Piggings Stations (GP-5A) and the General Plan Approval and General Operating Permit for Natural Gas Compression Stations, Processing Plants, and Transmission Stations (GP-5) released on *June 9, 2018*. The TSD includes the rationale for the air permitting requirements for air pollution sources and the associated air pollution controls covered by the General Permits. The TSD also describes sources common to all types of facilities, sources specific to GP-5A-eligible facilities, and sources specific to GP-5-eligible facilities.

According to 25 Pa. Code § 127.1, air contamination sources must be regulated to protect the public welfare, and new sources shall control air pollutant emissions to the maximum extent consistent with Best Available Technology (BAT) as determined by the Department. The federal New Source Performance Standards (NSPS) are incorporated into the Department's regulations by reference in 25 Pa. Code § 122.3, and the federal National Emissions Standards for Hazardous Air Pollutants (NESHAP) regulations are incorporated by reference in 25 Pa. Code § 127.35. Additionally, the current requirements of the U.S. Environmental Protection Agency's (EPA) NSPS for Crude Oil and Natural Gas Facilities (40 CFR Part 60, Subparts OOOO and OOOOa) and other federal requirements are incorporated by reference into the General Permits when the conditions are no different than the conditions determined by the Department to be BAT.

VI. Introduction

GP-5A and GP-5 have been developed under the authority of Section 6.1(f) of the Pennsylvania Air Pollution Control Act (APCA, 35 P.S. § 4006.1) and under section 504(d) of the Clean Air Act (CAA, 42 U.S.C. § 7661c(d)) which authorizes the establishment of a general permit program to regulate air contamination sources. *See also* 25 Pa. Code Chapter 127, Subchapter H. Additionally, section 6.6(c) of the APCA, 35 P.S. § 4006.6(c), authorizes the Department to require new sources to control air pollution through the use of BAT at the time of plan approval. *See also* 25 Pa. Code § 127.1.

The Department's regulatory General Permit program and BAT provisions were established in 1994. (24 Pa.B. 5899 (November 26, 1994)). These regulations were subsequently approved by EPA as part of Pennsylvania's State Implementation Plan (SIP) in 1996. (61 Fed. Reg. 39594 (July 30, 1996)). Currently, the Department has 18 air quality General Permits that regulate air contamination sources in several industrial categories, including small boilers, burn off ovens, storage tanks, lithographic printing, mineral processing, petroleum dry cleaning, powder metal sintering furnaces, and natural gas production.

A General Permit is a pre-approved plan approval and operating permit which applies to a specific category of sources, if the Department determines that those sources can be adequately regulated using standardized specifications and conditions. (35 P.S. § 4006.1(f)). As part of the General Permit process, the Department establishes BAT requirements for new sources. Those BAT requirements can include equipment, devices, methods, or techniques as determined by the Department, which will prevent, reduce, or control air emissions to the maximum degree possible and which are available or may be made available. (25 Pa. Code § 121.1). BAT is not a regulation but an analysis of control techniques that are determined at the time of the issuance of a plan approval. The Pennsylvania Environmental Hearing Board (EHB) has indicated that the requirement to conduct a BAT analysis for new sources extends to greenhouse gases (GHGs), including methane. (*Snyder v. DEP*, 2015 EHB 027). Moreover,

the Commonwealth Court has endorsed the Department's position that the General Assembly, through the APCA, gave the agency the authority to reduce GHG emissions. (*Wolf v. Funk*, 144 A.3d 228, 250 (Pa. Cmwlth. 2016)).

On September 21, 1996, the Department published the Air Quality Permit Exemptions, which specified sources or classes of sources that were determined to be exempt from the plan approval and permitting requirements of the APCA, 35 P.S. §4001 *et seq.* and 25 Pa. Code Chapter 127, which included crude oil and natural gas wells. The Department issued GP-5 on March 10, 1997, for natural gas production facilities. This established BAT for stationary natural gas-fired spark ignition reciprocating internal combustion engines (engines) rated from 100 brake horsepower (bhp) to 1,500 bhp and for glycol dehydrators with an uncontrolled potential to emit (PTE) volatile organic compounds (VOC) in excess of 10 tons per year (tpy) at natural gas production facilities. On July 27, 2006, DEP revised the GP-5 to expand the applicability to natural gas, coal bed methane, and gob gas production or recovery facilities, including gathering stations.

EPA has developed several regulations applicable to oil and natural gas production sites, natural gas compression stations, processing plants, and transmissions stations; these are 40 CFR Part 60, Subparts KKK, JJJ, KKKK, OOOO, and OOOOa and 40 CFR Part 60 Subparts HH, HHH, and ZZZZ. Some of these regulations require the control of methane emissions from sources at these facilities. Other pollutants that are regulated under these standards include VOC and hazardous air pollutants (HAP). The federal regulations apply to all oil and gas operations in the U.S. The Department is required to implement these federal regulations under Section 4 of the APCA, 35 P.S. §4004. In addition, these federal regulations are incorporated by reference into the *Pennsylvania Code* and, as a result, are Pennsylvania law. See 25 Pa. Code §§122.1, 124.1, and 127.35(b).

On February 2, 2013, the Department changed the applicability of GP-5 to natural gas compression and/or processing facilities, and established BAT requirements for engines, stationary natural gas-fired simple cycle turbines (turbines), natural gas compressors, storage vessels, glycol dehydrators, natural gas fractionation units, equipment leaks, pneumatic controllers, and sweetening units. The Air Quality Permit Exemptions were amended by the Department on August 10, 2013, to change the unconditional exemption of all crude oil and natural gas wells to the unconditional exemption of sources located at conventional well sites and a conditional exemption for sources located at unconventional natural gas well sites.

In 2009, based on a large body of scientific evidence, EPA issued an “Endangerment Finding” under the Clean Air Act (CAA) section 202(a)(1), 42 U.S.C. § 7521(a)(1), related to GHGs.¹ EPA found that six well-mixed GHGs — carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride — endanger both the public health and the public welfare of current and future generations by causing or contributing to climate change.² New scientific assessments and observations strengthen the conclusions of this Endangerment Finding that GHGs endanger public health and the environment.³ Methane traps 86 times more heat in the atmosphere than carbon dioxide in the short-term, increasing the consequences of climate change. Additionally, methane is often accompanied by toxic air pollutants such as benzene, formaldehyde, and ethylbenzene.

¹ “Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act,” 74 Fed. Reg. 66496 (December 15, 2009) (“Endangerment Finding”).

² *Id.*

³ “Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources,” 81 Fed. Reg. 35824 (June 3, 2016).

Methane is also a precursor to ground level ozone, which can cause a number of harmful effects on public health and the environment.⁴ Exposure to ozone can cause respiratory system effects such as difficulty breathing and airway inflammation.⁵ In addition, long-term exposure to ozone is likely to result in harmful respiratory effects, including respiratory symptoms and the development of asthma.⁶

There are also independent peer-reviewed studies which indicate that shale gas development is associated with the production of secondary pollutants such as tropospheric (ground-level) ozone, formed through the interaction of methane, VOC, and nitrogen oxides (NO_x) in the presence of sunlight.^{7,8} Tropospheric ozone is a strong respiratory irritant associated with increased respiratory and cardiovascular morbidity and mortality.⁹ Although toxicological data suggest that pure methane is not by itself health damaging (excluding its role as an asphyxiant and an explosive), it is a precursor to global tropospheric ozone.¹⁰

Based on all the information reviewed by the Department, which it adopts as its own, and incorporates by reference into this TSD, there is a strong scientific basis to show that methane meets the definition of air contaminant, air contamination, and air pollution under section 3 of the APCA. As a GHG and ozone precursor, methane is, among other things, inimical or may be inimical to the public health, safety, or welfare.

According to the U.S. Energy Information Agency (EIA), Pennsylvania was the nation's second-largest natural gas producer for the fourth consecutive year. The largest key sources of anthropogenic methane emissions in Pennsylvania include natural gas and oil systems (30.5 percent), coal mining (30.3 percent), landfills (21.1 percent), enteric fermentation from domestic livestock (9.9 percent), wastewater (3.9 percent), and manure management (2.3 percent). Of these major categories, natural gas and oil systems are the only areas that show significant growth, increasing threefold from the 1990s. The other major categories are either flat or slightly down from the 1990s. This shows that the oil and gas industry is therefore the largest category for methane emissions.

Based on information from the Department's emission inventory, there are approximately 31,224 sources at 4,960 well pad facilities and 4,285 sources at 493 compressor stations. The overall methane emissions from this source category in 2015 amounted to approximately 123,081 tons in Pennsylvania, which is an increase from 2014 levels. One peer-reviewed study indicates that new emissions data suggest that the recently instituted Pennsylvania methane emissions inventory substantially underestimates measured facility-level methane emissions by 10-40 times.¹¹

Pennsylvania Governor Tom Wolf introduced a methane reduction strategy on January 19, 2016. The four-point plan included the following strategies:

⁴ *Id.*

⁵ *Id.*

⁶ *Id.*

⁷ Shonoff, Hays, Finkel, *Environmental Health Dimensions of Shale and Tight Gas*, Environ Health Perspect., 2014 Aug; 122(8): 787–795.

⁸ Jerrett M, Burnett RT, Pope CA III, Ito K, Thurston G, Krewski D, *et al.* Long-term ozone exposure and mortality, N Engl J Med 360:1085–1095, 2009 and U.S. EPA Integrated Science Assessment for Ozone and Related Photochemical Oxidants (EPA 600/R-10/076F) Available at: <http://www.epa.gov/ncea/isa/ozone.htm>, last accessed on May 9, 2018.

⁹ Jerrett *et al.*

¹⁰ Smith KR, Jerrett M, Anderson HR, Burnett RT, Stone V, Derwent R, *et al.* Public health benefits of strategies to reduce greenhouse-gas emissions: health implications of short-lived greenhouse pollutants. Lancet 374:2091–2103, 2009.

¹¹ Omara, *et al.*, *Methane Emissions from Conventional and Unconventional Natural Gas Production Sites in the Marcellus Shale Basin*, Environ. Sci. Technol. 2016, 50, 2099–2107.

- To reduce leaks at new unconventional natural gas well pads, DEP will develop a new General Permit for oil and gas exploration, development, and production facilities, requiring BAT for equipment and processes, better recordkeeping, and quarterly monitoring inspections.
- To reduce leaks at new compression stations and processing facilities, DEP will revise its current General Permit, updating BAT requirements and applying more stringent leak detection and repair (LDAR) and other requirements to minimize leaks.
- To reduce leaks at existing oil and natural gas facilities, DEP will develop a regulation for existing sources for consideration by the Environmental Quality Board.
- To reduce emissions along production, gathering, transmission and distribution lines, DEP will establish best management practices (BMP), including LDAR programs.

On February 4, 2017, the Department published notice in the *Pennsylvania Bulletin* of the availability of the Proposed General Plan Approval and/or General Operating Permit No. 5A for Unconventional Natural Gas Well Site Operations or Remote Piggings Stations (“GP-5A”) and Proposed Modifications to General Plan Approval and/or General Operating Permit No. 5 for Natural Gas Compressor Stations, Processing Plants and Transmission Stations (“GP-5”) and proposed revisions to the Air Quality Permit Exemptions document (TGD Document No. 275-2101-003) for public review and comment. (47 Pa.B. 733). The public comment period was originally scheduled to close on March 22, 2017. However, due to increased public and legislative interest, the comment period was extended until June 5, 2017. (47 Pa.B. 1235). Then on March 31, 2018, the Department published another *Pennsylvania Bulletin* notice announcing an additional opportunity to submit comments on the draft final GPs until May 15, 2018. (48 Pa.B. 1902).

The final General Permits set forth standardized terms and conditions related to BAT, compliance certification, notification, recordkeeping, reporting, and source testing requirements. In addition, the General Permits require permittees to comply with any applicable federal NSPS. Under the final GPs, the Department determined that BAT for certain new sources is more stringent than the applicable NSPS, and, in other cases, the Department determined that BAT is the same as the applicable NSPS limit for certain new sources. A BAT standard does not replace a NSPS, but is in addition to a NSPS. The Department made its determinations based on a technical and economic feasibility analysis contained in this TSD. For instance, under GP-5, the Department made 13 separate BAT determinations for 13 separate sources, nine of which were more stringent than the applicable NSPS. Under GP-5A, the Department made 11 separate BAT determinations for 11 separate sources, of which eight were more stringent than the applicable NSPS.

The BAT emission reductions in Table 1 and Table 2 below are from sources that may be located at an unconventional well site or a mid-stream compressor station and are scientifically-based estimates. Actual emissions at an individual site depend on a case-by-case analysis that accounts for: gas production or throughput; type of equipment; management practices; and composition of the gas or liquids. Estimates of reductions are based on changes due to BAT requirements from the previous GP-5 and Exemption 38 to the final GP-5A and GP-5.

The new GP-5A is applicable to the sources located at unconventional natural gas well site operations and remote piggings stations, and the revised GP-5 is applicable to sources located at natural gas compression stations, processing plants, and transmission stations. The use of the GP-5 and GP-5A are restricted to facilities with actual emissions less than 100 tpy of criteria pollutants (NO_x, CO, SO₂, PM₁₀, and PM_{2.5}), less than 50 tpy of VOC, less than 10 tpy of any single HAP, and less than 25 tpy of total HAPs. For facilities located in Philadelphia, Bucks, Chester, Montgomery, or Delaware Counties, the NO_x and VOC emissions thresholds are less than 25 tpy each.

While the terms and conditions of both General Permits incorporate both federal and state requirements, it is the duty of the Responsible Official to ensure that the facility is in compliance with all applicable federal, state, and local laws and regulations, including 25 Pa. Code, Subpart C, Article III. Nothing in these General Permits relieves the Responsible Official from this obligation to comply.

Table 1 - Emissions Reduction Estimates for Sources at Unconventional Natural Gas Wells Sites

Source	Emissions Reduction Estimate							
	CH ₄ (tpy)		VOC (tpy)		HAP (lbpy)		NO _x (tpy)	CO (tpy)
Glycol Dehydration Units	1.04 ³	29%	No Change		No Change		NA	NA
Lean-Burn Engines (100 hp ≤ rating ≤ 500 hp)	NA		1.93	57%	NA		No Change	6.27 65%
Lean-Burn Engines (500 hp < rating < 2,370 hp)	NA		10.28	64%	NA		11.43 50%	40.00 88%
Lean-Burn Engines (rating ≥ 2,370 hp, 0.3 g/bhp-h NO _x)	NA		10.29	64%	NA		16.01 70%	40.01 88%
Lean-Burn Engines (rating ≥ 2,370 hp, SCR)	NA		10.29	64%	NA		21.72 95%	40.01 88%
Rich-Burn Engines (100 hp ≤ rating ≤ 500 hp)	NA		2.41	71%	NA		3.62 75%	8.20 85%
Rich-Burn Engines (rating > 500 hp)	NA		2.42	71%	NA		3.87 80%	8.22 85%
Reciprocating Compressors (EPA Emission Factors)	0.04	80%	0 ⁴	80%	0 ⁴	80%	NA	NA
Reciprocating Compressors (UT Average Emission Factors)	3.03	80%	0.16	80%	0.07	80%	NA	NA
Storage Vessels	1.04 ³	29%	No Change		No Change		NA	NA
Fugitive Emissions Components	6.36	20%	0.33	20%	0.15	20%	NA	NA
Pigging Operations ¹ (Monthly Frequency)	No Change ⁵							
Pigging Operations ¹ (Monthly Frequency – BMP reduces pressure to 125 psi)	1.57	90%	0.08	90%	0.04	90%	NA	NA
Pigging Operations ¹ (Daily Frequency)	50.41	95%	2.62	95%	1.18	95%	NA	NA
Wellbore Liquids Unloading ² (Monthly Frequency – BMP halves volume)	27.91	50%	1.45	50%	0.65	50%	NA	NA
Wellbore Liquids Unloading ² (Monthly Frequency – routed to control)	53.03	95%	2.76	95%	1.24	95%	NA	NA

¹ Pigging Operations were assumed to emit a volume of 90 ft³ at 1,250 psi.

² Wellbore Liquids Unloading Operations were assumed to emit a volume of 4,500 ft³ at 800 psi.

³ Methane emissions reductions based on assumed 93% destruction efficiency correlated to operating temperature for 95% VOC destruction efficiency.

⁴ Even though the table shows zero tons reduced, emissions are reduced by the following percentage.

⁵ Pigging Operations at the assumed volume and pressure to not exceed the control threshold at the monthly frequency.

Table 2 - Emissions Reduction Estimates for Sources at Natural Gas Compression Stations

Source	Emissions Reduction Estimate									
	CH ₄ (tpy)		VOC (tpy)		HAP (lbpy)		NO _x (tpy)		CO (tpy)	
Glycol Dehydration Units	4.14 ²	61%	0.12 ³	46%	0.05 ³	46%	NA		NA	
Lean-Burn Engines (100 hp ≤ rating ≤ 500 hp)	NA		1.93	57%	NA		No Change		6.27	NA
Lean-Burn Engines (rating ≥ 2,370 hp, 0.3 g/bhp-h NO _x)	NA		No Change		NA		4.57	40%	No Change	
Lean-Burn Engines (rating ≥ 2,370 hp, SCR)	NA		No Change		NA		10.29	90%	No Change	
Storage Vessels	5.48 ²	68%	0.17 ³	55%	0.07 ³	55%	NA		NA	
Tanker Truck Load-Out Operations	0.83 ³	55%	0.04 ³	55%	0.02 ³	55%	NA		NA	
Pigging Operations ¹ (Monthly Frequency)	No Change ⁴									
Pigging Operations ¹ (Monthly Frequency – BMP reduces pressure to 125 psi)	1.57	90%	0.08	90%	0.04	90%	NA		NA	
Pigging Operations ¹ (Daily Frequency)	50.41	95%	2.62	95%	1.18	95%	NA		NA	
Natural Gas-Fired Combustion Units (rating ≥ 10 MMBtu/h)	NA		NA		NA		0.80	50%	5.49	57%
Turbine (5,000 hp ≤ rating <15,900 hp)	NA		4.96	44%	NA		No Change		11.81	60%
Turbine (rating ≥ 15,900 hp – 9 ppm NO _x)	NA		No Change		NA		11.40	40%	No Change	
Turbine (rating ≥ 15,900 hp – SCR)	NA		No Change		NA		25.65	90%	No Change	
Centrifugal Compressor (Wet Seal Degassing Systems)	9.52 ²	29%	No Change		No Change		NA		NA	

¹ Pigging Operations were assumed to emit a volume of 90 ft³ at 1,250 psi.

² Methane emissions reductions based on assumed 93% destruction efficiency correlated to operating temperature for 95% VOC destruction efficiency.

³ Emissions reduction primarily based on reduction in control threshold.

⁴ Pigging Operations at the assumed volume and pressure to not exceed the control threshold at the monthly frequency.

I. Definitions

Words and terms that are not otherwise defined in the General Permits have the meanings set forth in Section 3 of the APCA (35 P.S. § 4003) and Title 25, Article III, including 25 Pa. Code § 121.1 (relating to definitions), unless the context indicates otherwise. The meanings set forth in applicable definitions codified in the Code of Federal Regulations including 40 CFR Part 60 Subparts JJJJ, KKKK, OOOO, and OOOOa or 40 CFR Part 63 Subparts HH and ZZZZ also apply to these General Permits.

Coal bed methane – Methane that is extracted from a coal bed and the surrounding rock strata by extraction wells drilled in advance of a mining operation, which is typically of pipeline quality.

Fugitive Emissions Component – Any component that has the potential to emit fugitive emissions of methane, VOC, or HAP at a facility, but not limited to, valves, connectors, pressure relief devices, open-ended lines, flanges, compressors, instruments, meters, covers, and closed vent systems. Devices that vent as part of normal operations are not considered fugitive sources unless the emission originates from a place other than the vent.

Gob gas – Methane that is mixed with air from a mine ventilation system due to the mining operation reaching the area of an extraction well, which is typically below pipeline quality.

Leak – A leak is defined as any release of gaseous hydrocarbons that is detected by Auditory, Visual, or Olfactory (AVO) inspection; an optical gas imaging (OGI) camera calibrated according to 40 CFR §60.18 and a detection sensitivity level of 60 g/h; a gas leak detector that meets the requirements of 40 CFR Part 60, Appendix A-7, Method 21 that detects a concentration of 500 ppm calibrated as methane or greater; or other leak detection methods approved by the Department's Division of Source Testing and Monitoring. However, a release from any equipment or component designed by the manufacturer to protect the equipment, controller, or personnel or to prevent groundwater contamination, gas migration, or an emergency situation is not considered a leak.

Natural Gas Compression Station – A facility that compresses and/or processes natural gas, coal bed methane, or gob gas prior to the point of custody transfer using processes including, but not limited to, gas dehydration, compression, pigging, and storage.

Natural Gas Processing Plant – A facility that engages in the extraction of natural gas liquids from field gas, the fractionation of mixed natural gas liquids to natural gas products, or both extracts and fractionates natural gas liquids.

Natural Gas Transmission Station – A facility that compresses and/or processes natural gas after the point of custody transfer using processes including, but not limited to, gas dehydration, compression, pigging, and storage.

Pigging Operations – The process of removing and collecting condensed liquids including condensate, intermediate hydrocarbons, or produced water from a pipeline using a spherical or bullet-shaped device, known as a pig, forced through the pipeline by natural gas pressure. The liquids are then collected at their eventual destination in a storage tank, often referred to as a slug tank. This process also includes operation conducted for pipeline integrity evaluation.

Point of Custody Transfer – The location after the processing and/or treatment of natural gas in the production sector, typically after a natural gas processing plant, where control and/or ownership of the natural gas is transferred from one owner or operator to another.

Remote Pigging Station – A facility where pigging operations are conducted that is not located at an unconventional natural gas well site, natural gas compression station, natural gas processing plant, or natural gas transmission station and which meets or exceeds the exemption criteria in Category 38(c) of the Air Quality Permit Exemptions List.

Sour Gas – Natural gas where the Hydrogen Sulfide (H₂S) content is in excess of 4 ppmv at standard temperature and pressure.

Start of Production – The beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate, or produced water. A well whose owner or operator is selling gas through temporary equipment designed for flowback shall not be considered in production until either the sales continue through the temporary equipment for more than 30 days or the gas is routed to a permanent production separator.

Unconventional Natural Gas Well – A well drilled to produce natural gas from shale formations below the Elk Group or its geologic equivalent stratigraphic interval, where recovery of the resource is generally not economic without the bores being stimulated by hydraulic fracturing, multilateral well bores, or other techniques to expose more of the formation to the well bore.

Unconventional Natural Gas Well Site – A location with one or more unconventional natural gas wells at which unconventional natural gas well site operations are conducted.

Unconventional Natural Gas Well Site Operations – Equipment and processes at unconventional natural gas well sites including, but not limited to, well completion, gas dehydration, tanker truck load-out, wellbore liquids unloading, gas compression, pigging, and storage.

Wellbore Liquids Unloading – The process of removing accumulated liquids from a natural gas well in order to restore well pressure and natural gas production.

VII. Applicability/Scope

GP-5A authorizes the construction, modification, and/or operation of sources located at an unconventional natural gas well site or remote pigging station. The applicability of the GP-5A may include one or more of the following operations or emissions sources:

- Glycol Dehydration Units
- Stationary Natural Gas-Fired Spark Ignition Internal Combustion Engines
- Reciprocating Compressors
- Storage Vessels
- Tanker Truck Load-Out Operations
- Fugitive Emissions Components
- Controllers
- Pumps
- Enclosed Flares and Other Control Devices
- Pigging Operations
- Wellbore Liquids Unloading Operations

GP-5 authorizes the construction, modification, and/or operation of sources located at natural gas compression station, processing plant, or transmission station. The applicability of the GP-5 may include one or more of the following operations or emissions sources:

- Glycol Dehydration Units
- Stationary Natural Gas-Fired Spark Ignition Internal Combustion Engines
- Reciprocating Compressors
- Storage Vessels
- Tanker Truck Load-Out Operations
- Fugitive Emissions Components
- Controllers
- Pumps
- Enclosed Flares and Other Control Devices
- Pigging Operations
- Natural Gas-Fired Combustion Units
- Stationary Natural Gas-Fired Combustion Turbines
- Centrifugal Compressors

An Application for Authorization to Use GP-5 or GP-5A may be submitted for the operation of an eligible source if the source is exempted from plan approval requirements under 25 Pa. Code §127.14. If any source located at a facility cannot be regulated under the appropriate General Permit, a plan approval and/or an operating permit issued in accordance with 25 Pa. Code, Chapter 127, Subchapter B and/or Subchapter F will be required.

VIII. Prohibited Use of GP-5 and GP-5A

The proposed GP-5 and GP-5A are different from many other General Permits issued by the Department. The General Permit program typically establishes a general plan approval/general operating permit with requirements for a specific type of **source**, and can be used at Title V facilities when they are adding that type of source to the facility. However, GP-5 and 5A are eligible for sources located at non-major facilities. Since 1997, Authorizations to Use GP-5 issued for natural gas facilities were applicable only for sources located at non-major facilities. The sources located at Title V or major facilities must obtain a site-specific plan approval and operating permit.

In addition, because most of the natural gas production in the Marcellus Shale and Utica Shale Region is not sour gas, the GP-5 and 5A are prohibited for use by those facilities that produce or process sour gas. This removes the necessity to include the sweetening unit requirements and means many of the federal SO₂ requirements in 40 CFR Part 60 are presumptively met.

The owner or operator of a facility is also prohibited from circumventing the requirements for Title V applicability, the prevention of significant deterioration, or non-attainment new source review by allowing a pattern of ownership or development that conceals that the facility would otherwise be required to submit a plan approval or operating permit application. This includes specifically phasing, staging, delaying, or engaging in incremental construction over the geographical extent of the facility or using a device, stack height that exceeds good engineering practice, dispersion technique, or other technique to conceal or dilute emissions of air contaminants without reducing the amount of emissions in order to appear to qualify for the General Permit when the facility should actually be authorized under a plan approval or operating permit.

IX. Authorization to Use the General Permits

The general procedure to apply for an Authorization to Use the General Permit; the terms; expiration and reauthorization procedure; transfer of ownership; administrative amendment; and conditions relating

to the modification, suspension, or revocation of the General Permit or an Authorization to Use the General Permit are detailed in Condition 6 of the General Permits. Application Instructions and Application Forms for the General Permits can be found in the Department's e-Library. In addition, electronic applications can be submitted using the Department's e-Permitting system, accessible through DEP's Greenport.

Another important modification to this Condition is the Transfer of Ownership procedure. In previous versions of the GP-5, the new owner or operator was required to submit a new application form within 30 days of the transfer of ownership. The new procedure, which is available in both GP-5 and GP-5A, is for the new owner or operator to file the appropriate form; for a transfer of ownership that does not modify any existing source, is not adding a new source, and is not subject to a new Single Source Determination the owner or operator may submit the Transfer of Ownership Form with the appropriate fee. For a transfer of ownership that does not modify any existing source, is not adding a new source, but requires a new Single Source Determination (i.e., equipment or activities located on the same site or on sites that share equipment and are within ¼ mile of each other) the new owner or operator shall submit an application for Authorization to Use the General Permit as a General Plan Approval with the appropriate fee. For a transfer of ownership that modifies an existing source or adds a new source, the new owner or operator shall submit an application for Authorization to Use the General Permit using the standard procedure.

X. General Permit Fees

The fees related to the General Permits are detailed in Condition 7. All fees are assessed in accordance with 25 Pa. Code Chapter 127 Subchapter I.

XI. Applicable Laws

The terms and conditions of the proposed GP-5 and 5A incorporate both federal and state requirements. It is the duty of the Responsible Official to ensure that the facility is in compliance with all applicable laws and regulations, and nothing in the General Permits relieves the Responsible Official of that duty. Therefore, it is suggested that owners and operators carefully review the listed sources and the federal, state, and local requirements applicable to them and compare them to the terms and conditions of the General Permit.

The Department's review has found that the applicable federal regulations include the following NSPS and NESHAP subparts:

- (a) **40 CFR Part 60, Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines.** This subpart establishes emission standards and compliance requirements for the control of emissions from stationary spark ignition internal combustion engines that commenced construction, modification or reconstruction after June 12, 2006, where the SI-RICE are manufactured on or after specified manufacture trigger dates. The manufacture trigger dates are based on the engine type, fuel used, and maximum engine horsepower. The state BAT requirements for engines at natural gas compression and/or processing facilities under the current GP-5 are either equivalent or more stringent than the federal requirements.
- (b) **40 CFR Part 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines.** This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines with a heat input at peak load equal to or greater than 10 million British thermal units per hour (MMBtu/h) that commenced construction,

modification or reconstruction after February 18, 2005. The pollutants regulated by this subpart are NO_x and sulfur dioxide (SO₂). However, the SO₂ requirements can be met by fuel composition analysis, and the prohibition of using the General Permits for facilities that produce or process sour gas ensures that the fuel composition analysis will be met.

- (c) **40 CFR Part 60, Subpart OOOO – Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution for which Construction, Modification, or Reconstruction Commenced after August 23, 2011, and on or before September 18, 2015.** This subpart establishes emission standards and compliance schedules for the control of VOC and SO₂ emissions from affected facilities. In Subpart OOOO, the only SO₂ emission source is the sweetening unit typically located at natural gas processing plants. The prohibition of using the General Permits for facilities that produce or process sour gas makes it unlikely that a sweetening unit will produce significant SO₂ emissions, so the requirements for the sweetening unit were not included.
- (d) **40 CFR Part 60, Subpart OOOOa – Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced After September 18, 2015.** This subpart establishes emission standards and compliance schedules for the control of the pollutant greenhouse gases (GHG). The GHG standard in this subpart is in the form of a limitation on emissions of methane. This subpart also establishes emission standards and compliance schedules for the control of VOC and SO₂ emissions. As for Subpart OOOO, the prohibition of using the General Permits for facilities that produce or process sour gas makes it unlikely that a sweetening unit will produce significant SO₂ emissions, so the requirements for the sweetening unit were not included.
- (e) **40 CFR Part 63, Subpart HH – National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities.** This subpart applies to the owners and operators of affected units located at natural gas production facilities that are major or area sources of HAPs and that process, upgrade, or store natural gas prior to the point of custody transfer, or that process, upgrade, or store natural gas prior to the point at which natural gas enters the natural gas transmission and storage source category or is delivered to a final end user. Because the GP-5 and 5A require that the facility is non-major with respect to air pollution, only the area source requirements apply. Area sources are broken down into two categories, those located within an Urbanized Area (UA) plus offset or an Urbanized Cluster (UC) and those not located within a UA plus offset or UC.
- (f) **40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE).** This rule establishes national emission limitations and operating limitations for HAPs emitted from stationary RICE. This rule applies to owners or operators of new and reconstructed stationary RICE of any horsepower rating which are located at a major or area source of HAP emissions. While all stationary RICE located at major or area sources are subject to the final rule, in the context of these General Permits, only four-stroke engines above 500 bhp have BACT requirements; all others have work practice requirements. In addition, for engines that commenced construction, modification or reconstruction after June 12, 2006, compliance with 40 CFR Part 60, Subpart JJJJ meets the requirements of this subpart.

XII. Best Available Technology Requirements

New sources are required to control emissions of air pollutants to the maximum extent, consistent with BAT as determined by the Department as of the date of issuance of the plan approval for the new source as required under 25 Pa. Code §127.1. Condition 1 (BAT Compliance Requirements) in Sections B through L of GP-5A and in Sections B through N of GP-5 are determined to meet the BAT requirements.

XIII. Compliance Requirements and Compliance Certification

These General Permits function as a plan approval and operating permit only for a synthetic minor or natural minor facility. The Conditions of Section A lay out general terms and conditions to ensure that a facility remains a minor facility. The primary requirement to use these GPs is that the emissions from all sources and associated air pollution control equipment located at a facility must not exceed the major source thresholds on a 12-month rolling sum basis.

The owner or operator must constrain the facility throughput, hours of operation, and/or emissions from sources at the facility to ensure that the major source thresholds are not exceeded and keep records adequate to demonstrate compliance.

This Condition also contains requirements that all sources and associated air pollution control equipment are operated so as not to cause air pollution, operated and maintained in accordance with the manufacturer's specifications, operated and maintained in accordance with the fugitive emission requirements, and operated and maintained to limit the detection of malodors outside the property boundary. The addition of the fugitive emission requirements clause in the revised permit replaces the proposed version's Section B. Fugitive Particulate Matter, which was removed from both the GP-5 and GP-5A.

Another key compliance requirement is that the General Permits cannot be used to relax BAT previously established through the air quality permitting process. The owner and operator may not obtain a General Permit if BAT requirements in their current permit are more stringent than those in the revised General Permits. However, an owner or operator may elect to obtain a General Permit in lieu of their current plan approval or operating permit if they demonstrate they will be able to meet the applicable General Permit BAT requirements.

Finally, the Responsible Official must sign and submit a Certification of Compliance with the annual report.

XIV. Notification Requirements

There are several notifications that the owner or operator of a facility must perform, including a municipal notification to the local governments where the air pollution source is to be located. A copy of this notification is required to be included in the Application for Authorization to Use GP-5 or GP-5A. The notification to the local governments should include a description of the proposed sources and/or modification of existing sources to be authorized under the application.

Notifications to the Department for individual sources include prior notification of the commencement of operation of a source, which must include the completion of construction date. Notification of malfunctions are performed according to the GP-5 Malfunction Reporting Instructions (See Appendix I

– GP-5 Malfunction Reporting Instructions). All notices must be submitted to the Air Program Manager of the appropriate DEP Regional Office.

XV. Recordkeeping Requirements

Any records generated as part of the terms and conditions of the General Permits are required to be maintained on site or at the nearest local field office for a minimum of 5 years and may be maintained in electronic format. The key records generated and maintained by the owner or operator of a facility authorized under the General Permit are those that show the facility is in compliance with the facility-wide emission limits on a 12-month rolling basis. All records, reports, or other information obtained by the Department under the General Permit is publicly available unless the owner or operator of the facility shows cause that the information is confidential. Under no circumstance are records of emission data eligible for confidentiality as set forth in Section 13.2 of the APCA. 35 P.S. § 4013.2.

XVI. Reporting Requirements

In order to manage the federal and state reporting requirements, the Department merged all reporting requirements into a single annual report that is required to be sent to the Department no later than 60 days from the anniversary of the Authorization to Use the General Permit. The owner or operator may send a copy of the annual report to the EPA as all federal requirements are included, or the owner or operator may send a version that redacts all state requirements at their discretion. The annual report serves as the basis for the Compliance Certification, which the Responsible Official must sign. The annual report must be submitted either in electronic format or by hand-delivery, courier, or sent by certified mail, return receipt requested, to the Air Program Manager of the appropriate DEP Regional Office. The owner or operator of the facility must also submit an annual emissions inventory via AES*Online or AES*XML to the Department by March 1st of each year.

XVII. Source Testing Requirements

All submittals, including all reports, protocols, and test completion notifications and excluding periodic monitoring data, related to Source Testing must include one hard copy and one electronic copy sent to the Air Program Manager of the appropriate DEP Regional Office and one hard copy and one electronic copy sent to the PSIMS Administrator for the Source Testing Section in DEP Central Office.

The submission of a test protocol must be done at least 60 days prior to the performance of a source test to demonstrate compliance with the General Permits. An operator may request an approval from the Department for a test protocol that covers testing of all currently operated sources in service at that operator's various facilities. In such a request, the operator will submit the test protocol that includes a list of currently permitted sources and that meets the applicable requirements specified in the most current version of the Department's Source Testing Manual for review and approval. In the case that the owner or operator has a test protocol previously approved by the Department (including the testing contractor), a new test protocol is not required provided that there are no changes, and the owner or operator agrees to comply with all conditions of acceptance in the letter approving the protocol.

The frequency of the tests required is based on federal and state requirements. In most cases, the requirements are identical; however, in the case of engines, there are some discrepancies in the timing and frequency of the tests. These discrepancies are outlined in Table 3, with the caveats noted below the table.

Table 3 - Engine Source Testing Requirements

Engine Size	Initial Compliance Performance Test	Continuous Compliance Performance Test	Periodic Monitoring
<100 hp	None Required	None Required	Every 2,500 hours of operation
100 hp ≤ ER ≤ 500 hp	Within 180 days of startup of the engine	Within 180 days of each reauthorization	Every 2,500 hours of operation
>500 hp and not subject to 40 CFR Part 60 Subpart ZZZZ	Within 180 days of startup of the engine	Every 8,760 hours of operation <u>or</u> every three years <u>and</u> within 180 days of each reauthorization	Every 2,500 hours of operation
> 500 hp and subject to 40 CFR Part 60, Subpart ZZZZ	Not Applicable	Every year	Every 2,500 hours of operation

For an engine rated greater than or equal to 100 hp and less than or equal to 500 hp, if the engine is certified by the manufacturer in accordance with 40 CFR Part 60, Subpart JJJJ and the owner or operator operates and maintains the engine in accordance with the manufacturer's instructions, the performance testing requirements are waived.

For an engine rated greater than 500 hp, if the engine is certified by the manufacturer in accordance with 40 CFR Part 60, Subpart JJJJ and the owner or operator operates and maintains the engine in accordance with the manufacturer's instructions, the continuous compliance performance testing requirements every 8,760 hours of operation or every three years are waived.

There are also some differences between the federal and state requirements for testing for combustion turbines, primarily which pollutants are analyzed during the test. The Department requires testing for NO_x, CO, and NMNEHC (as propane) while the federal regulation requires testing of NO_x and SO₂ only. It is the Department's determination that SO₂ testing is not required based on 40 CFR §60.4415(a)(1) if the fuel used is either pipeline quality gas or field gas that does not meet the definition of sour gas. There is also a frequency difference in that the federal regulations require annual testing for turbines that do not use water or steam injection for NO_x control. The annual requirement can be waived if the owner or operator installs a continuous monitoring system.

In all cases and for all sources, the Department may alter the frequency of performance testing for reauthorization based on available performance data from the source, unless the performance tests are required by federal regulation.

XVIII. General Methodology of Determining Best Available Technology

New sources are required to control the emission of air pollutants to the maximum extent, consistent with BAT as determined by the Department. BAT is defined in 25 Pa. Code §121.1 as equipment, devices, methods, or techniques as determined by the Department which will prevent, reduce, or control emissions of air contaminants to the maximum degree possible and which are available or may be made available. The applicable emission limits of federal NSPS and NESHAPs serve as minimum

requirements for determining BAT. The resources utilized in the determination of BAT include the conditions established for similar sources in Category 38 of the Air Quality Permit Exemptions; the current GP-5; the data in EPA's RACT/BACT/LAER Clearinghouse (RBLC); case-by-case BAT determined in recently issued plan approvals; and permits recently issued by other states. The Department also evaluated vendors' guaranteed emission limits, available stack test data for the applicable sources, and documents related to EPA's Natural Gas Star (NGStar) program. The emission limitations included in the General Permits must be technically and economically feasible and must be sustainable during the life of the air pollution source.

The general classes of air emissions from the sources at facilities covered by GP-5 and GP-5A include NO_x, CO, VOC, HAP, SO_x, PM₁₀, PM_{2.5}, CO₂, and methane. These pollutants are described in more detail below.

A. Oxides of Nitrogen

Oxides of nitrogen are a family of compounds which includes nitrogen oxide (NO) and nitrogen dioxide (NO₂) that are produced as a byproduct of the combustion of fuel and air. The heat of combustion causes the molecular nitrogen (N₂) in the combustion air to disassociate and oxidize, forming NO and NO₂. NO_x is a criteria pollutant, but it is also a precursor to acid rain, ozone, and PM_{2.5}; NO_x emissions are typically expressed as NO₂.

There are three types of NO_x created during combustion: thermal, fuel, and prompt. Thermal NO_x is produced at very high temperatures by the reaction of atmospheric oxygen and nitrogen and is heavily influenced by combustion temperature. Fuel NO_x results from oxidation of nitrogen contained in the fuel. Prompt NO_x is formed from molecular nitrogen in the air combining with fuel in fuel-rich conditions.

Strategies for the control of NO_x include combustion control and post-combustion control. In combustion control, the combustion temperature is lowered in order to limit the disassociation of molecular nitrogen through premixing, staging, or excess air. Post-combustion control typically includes an add-on device, such as nonselective catalytic reduction (NSCR) systems or selective catalytic reduction (SCR) systems. Both systems are described in greater detail in the individual source BAT analysis.

B. Carbon Monoxide

Carbon monoxide is a colorless, odorless gas that results from the incomplete combustion of carbon. CO is formed when insufficient oxygen or poor mixing interferes with the combustion reaction to produce CO₂. CO formation is greatest when the air-to-fuel (A/F) mixture is rich; however, CO also forms when a very fuel-lean mixture cannot sustain complete combustion.

Techniques for control of carbon monoxide also include combustion control and post-combustion controls. As for combustion control, a balance must be sought with NO_x control as lower combustion temperatures that prevent thermal NO_x formation can lead to incomplete combustion and therefore increase CO formation. Post-combustion controls include NSCR systems and oxidation catalysts. Individual source BAT analyses tend to favor minimizing NO_x production through combustion control techniques even though there may be an increase of CO, and then use post-combustion controls to mitigate the CO impact because Pennsylvania is a non-attainment state in the Ozone Transport Region.

C. Volatile Organic Compounds

VOCs are defined in 25 Pa Code §121.1. For engines and turbines, the Department uses non-methane, non-ethane hydrocarbons (NMNEHC) expressed as propane, excluding formaldehyde, in lieu of VOC. Also, the final General Permits include a separate emission limit for formaldehyde (HCHO), which is both a VOC and a HAP, for engines.

Techniques for the control of VOC are different depending on whether they are byproducts of combustion, due to venting or processing natural gas, or a result of fugitive emissions. Control techniques considered for the reduction of post-combustion VOC include NSCR systems and oxidation catalysts. The primary control technique considered for the reduction of venting or process emissions is the installation of a closed vent system routed to a process or a control. The primary control technique considered for the reduction of fugitive emissions is an LDAR program.

D. Hazardous Air Pollutants

HAPs are air pollutants known to cause cancer or to have other serious health impacts. There are currently 187 listed HAPs. While combustion accounts for a portion of HAP emissions, HAPs are also released through fugitive emissions, venting, and the processing of natural gas. The HAPs of primary concern at unconventional natural gas well site operations, remote pigging stations, natural gas compression stations, processing plants, and transmission stations are n-hexane; benzene, toluene, ethylbenzene, xylenes (collectively known as BTEX); and formaldehyde. Formaldehyde is of interest because it is the predominant HAP component of combustion emissions, resulting from the incomplete combustion of methane.

Similar to the control of VOC, the techniques for mitigating HAP emissions are dependent on whether the emissions are byproducts of combustion, due to venting or processing natural gas, or a result of fugitive emissions. The techniques to reduce HAP in these cases are the same as those used to reduce VOCs.

E. Oxides of Sulfur

Oxides of sulfur are the byproduct of combustion of a fuel that contains sulfur. In the Marcellus Shale region, natural gas does not contain sulfur above trace amounts. The Department has determined that for a typical combustion process using natural gas, SO₂ emissions are of minor significance. Therefore, neither GP-5 nor GP-5A include SO₂ emission limitations or SO₂ stack testing requirements for combustion sources. An example of this determination of minor significance is given in the calculation below.

$$\left| \frac{4 \text{ lb} \cdot \text{mol } H_2S}{10^6 \text{ lb} \cdot \text{mol natural gas}} \right| \left| \frac{\text{lb} \cdot \text{mol } SO_2}{\text{lb} \cdot \text{mol } H_2S} \right| \left| \frac{64.07 \text{ lb } SO_2}{\text{lb} \cdot \text{mol } SO_2} \right| \left| \frac{\text{lb} \cdot \text{mol natural gas}}{386.8 \text{ scf natural gas}} \right| \left| \frac{\text{scf natural gas}}{1,030 \text{ Btu}} \right| \left| \frac{10^6 \text{ Btu}}{\text{MMBtu}} \right|$$
$$= 6.42 \times 10^{-4} \frac{\text{lb } SO_2}{\text{MMBtu}} < 6.00 \times 10^{-2} \frac{\text{lb } SO_2}{\text{MMBtu}} (40 \text{ CFR } §60.4330(a)(2))$$

Another example is the sweetening unit sulfur feed rate, where the lowest applicable limit is two long tons per day. Using the equations provided in 40 CFR §60.5406a(b)(1) and assuming the 4 ppm H₂S limit, the “acid gas” flow rate would have to be nearly 13,500 MMscf/day to reach a sulfur feed rate of

two long tons of sulfur per day. According to a EIA report,¹² an average transmission station moves approximately 700 MMscf/day and the largest compression station at the time moves as much as 4,600 MMscf/day. Neither type of facility would reach the required sulfur feed rate for control under 40 CFR §60.5405(a). This is also true for gathering stations as they are generally smaller than transmission stations.

F. Particulate Matter

There are many types of particulate matter emissions, with classifications based on size (i.e., PM₁₀ and PM_{2.5}) and state (i.e., filterable and condensable). Some particles are emitted directly from a source, such as construction sites, unpaved roads, or combustion, and are called primary particles. Others are formed in complicated reactions in the atmosphere from SO₂ and NO_x and are called secondary particles. The clearing, grading, and construction of a site as well as the drilling of a well can create primary particle emissions. The combustion of natural gas produces very little primary particle emissions, and the control of precursor emissions helps reduce secondary particle emissions. Because the primary particle emissions from combustion sources are of minor significance, and the primary precursor emissions are either of minor significance or well controlled, GP-5 and GP-5A do not include PM emission limitations or stack testing requirements from most combustion sources.¹³

G. Carbon Dioxide

Carbon dioxide is sometimes present in natural gas in significant quantities and is also a primary byproduct of combustion. CO₂ is a greenhouse gas; however, since the explicit control of CO₂ emissions such as carbon capture and sequestration (CCS) from minor facilities such as sources covered by these General Permits are not readily available. However, many of the BMP, maintenance requirements, and operating limitations included in the General Permits have the co-benefit of increasing the source's efficiency and therefore reducing CO₂ on an output basis.

H. Methane

Methane is the primary component of natural gas and represents a major portion of the emissions from unconventional natural gas well site operations, remote pigging stations, natural gas compression stations, processing plants, and transmission stations. While methane is harmless in low concentrations, it can explode when the concentration reaches the lower explosive limit. Methane is also a greenhouse gas and a precursor to ground level ozone.

Based on the 2015 Air Emissions Inventory for unconventional natural gas operations, methane emissions from 2011 through 2015 ranged from 107,375 tpy to 122,589 tpy. The sources of methane emissions included dehydration units, fugitive sources such as connectors, flanges, pump lines, pump seals, valves, heaters, pneumatic pumps, stationary engines, tanks, venting, blowdowns, well completions and pigging operations. Details of methane emissions from the above sources are shown in Table 4 and Table 5.

¹² Technical Report: Natural Gas Compressor Stations on the Interstate Pipeline Network: Developments Since 1996, November 2007, Energy Information Administration, Office of Oil and Gas.

¹³ Technical Report: Development of Fine Particulate Emission Factors and Speciation Profiles for Oil and Gas-fired Combustion Systems, Update: Critical Review of Source Sampling and Analysis Methodologies for Characterizing Organic Aerosol and Fine Particulate Source Emission Profiles, February 2004, Gas Research Institute, *et.al.*

The Exemption 38, finalized in 2013, required 95% control of any emission unit exceeding emission thresholds of 2.7 tpy of VOC, 0.5 tpy of single HAP, and 1.0 tpy of total HAP. It should be noted that not a single plan approval was submitted for an unconventional natural gas well site despite the requirement to install 95% VOC control on storage vessels and other equipment. This means either the installation of control is cost effective, or that the sources in question emit less than 2.7 tpy of VOC, 0.5 tpy of single HAP, and 1.0 tpy of total HAP.

The control of methane emissions in the earlier GP-5s and Exemption 38 were addressed as a collateral benefit due to the control of VOC emissions; however, because of the great success with the 2.7 tpy VOC threshold in Exemption 38, the Department decided to do something similar with methane related to a cost-effective control threshold under BAT. In addition, the leak definition for oil and gas operations included in GP-5 and Exemption 38 expressly addressed methane emissions from fugitive sources. As previously discussed in the Introduction, Governor Wolf's Methane Reduction Strategy sought to explicitly address the control of methane from the oil and gas industry. Also, as previously discussed in the Introduction, the EHB indicated to the Department that BAT also applies to GHG. Therefore, BAT for methane control was determined for sources authorized under the final General Permits to satisfy both regulatory and policy requirements.

Table 4 - Methane Emissions from Unconventional Well Site Operations in Pennsylvania

Source Type	2012		2013		2014		2015		2016	
	(tpy)		(tpy)		(tpy)		(tpy)		(tpy)	
Blowdown Vent	2,483	3%	3,745	7%	13,336	23%	12,527	21%	12,090	22%
Well Completion	39,449	54%	12,101	24%	2,237	4%	6,237	11%	7,071	13%
Dehydration Units	8,130	11%	6,402	13%	11,630	20%	6,112	10%	5,531	10%
Drilling Rigs	47	0%	33	0%	105	0%	20	0%	8	0%
Engines	3	0%	79	0%	102	0%	2	0%	26	0%
Fugitive Emissions	3,675	5%	6,081	12%	6,708	11%	11,136	19%	8,561	16%
Heaters	127	0%	12	0%	10	0%	33	0%	33	0%
Pumps	15,270	21%	19,157	38%	22,716	39%	22,007	37%	20,688	38%
Tanks	3,626	5%	3,041	6%	1,544	3%	1,169	2%	853	2%
Total	72,809	100%	50,650	100%	58,388	100%	59,244	100%	54,860	100%

Table 5 - Methane Emissions from Midstream Gas Compression and Processing Facilities in Pennsylvania

Source Type	2012		2013		2014		2015		2016	
	(tpy)		(tpy)		(tpy)		(tpy)		(tpy)	
Blowdown Vent	5,572	12%	10,575	19%	8,883	20%	16,640	26%	17,731	30%
Dehydration Units	14,259	29%	24,846	44%	16,066	36%	11,705	19%	12,290	20%
Engines	3,916	8%	5,731	10%	8,574	19%	11,418	18%	7,706	13%
Fugitive Emissions	2,930	6%	3,320	6%	4,032	9%	8,813	14%	7,429	12%
Heaters	5	0%	13	0%	8	0%	1,054	2%	769	1%
Pigging	NA	NA	NA				997	2%	192	0%

Pumps	8,102	17%	9,810	17%	4,309	10%	9,382	15%	12,410	21%
Tanks	13,638	28%	2,602	5%	2,490	6%	2,998	5%	1,450	2%
Total	48,424	100%	56,897	100%	44,363	100%	63,007	100%	59,976	100%

The Department originally proposed a BAT methane control threshold of 200 tpy based on calculating the amount of methane based on the VOC control threshold and an average gas composition as shown in Table 15 of Appendix A – Average Gas Composition Analysis. To calculate the BAT methane control threshold, the Department used a standard mass-balance calculation; the general methodology for determining the methane control threshold was to calculate the amount of methane in a natural gas release relative to the amount of VOC that reaches the VOC control threshold. Using twelve different gas samples, the BAT methane control thresholds ranged from a minimum of 21.2 tpy to a maximum of 1,615.3 tpy. The average of the twelve calculated control thresholds is 714.9 tpy, which is 17,872 tpy of CO_{2e}. This value is nearly 25% of the 75,000 tpy of CO_{2e} major modification facility threshold for greenhouse gases.

Therefore, the Department calculated an average gas composition from the twelve samples and followed the same methodology for determining the methane control threshold with a result of 191.6 tpy. The Department conservatively used 200 tpy methane to account for the scientific uncertainty due to the limited number of gas samples used in the calculation, which is equivalent to 5,000 tpy CO_{2e}. This is approximately 7% of the facility greenhouse gas threshold.

Several commentators stated that the Department's calculated average gas composition was not representative of natural gas in Pennsylvania because of its small sample size and limited geographic scope. To improve the average gas composition calculation, the Department decided to expand the scope of the analysis; for every county with wells displayed on eMapPA, the Department attempted to obtain at least five reasonable representative gas analyses, two from compressor stations or processing plants, and three from unconventional natural gas well sites. The Department then calculated a county average gas composition for each county, and a state average gas composition by averaging the county average gas compositions.

The average composition for the counties with at least one representative gas analysis and the calculated state average gas composition are shown in Table 16 of Appendix A – Average Gas Composition Analysis. The Department believes that this state average gas composition is representative of the regions where oil and gas operations are occurring. The same process was followed as in the previous analysis, where methane emissions were calculated based on a standard mass-balance and the VOC control threshold of 2.7 tpy for each county. The methane control thresholds ranged from 5.8 tpy for Mercer County and 1,474.8 tpy for Somerset County with an average methane control threshold of 444.0 tpy. While this value is lower than the 714.9 tpy value of the previous analysis, the Department determined that it is unreasonable to be used as a control threshold; this is because it is approximately 15% of the major modification facility threshold for GHG. For the calculated state average composition, the methane control threshold is calculated to be 51.9 tpy; this is lower than in the previous calculation because there were more representative gas analyses with VOC weight percentages higher than 2%.

In the first analysis, there were only two samples with VOC weight percentages over 2% and one of them was questionable due to the high nitrogen content; this means only 10% - 17% of the samples had a VOC weight percentage over 2%. In the second analyses, approximately 25% of the samples had VOC weight percentages over 2%; half of those samples had VOC weight percentages over 5% and one

had a VOC weight percentage over 25%. This higher VOC weight percentage had the effect of lowering the methane emissions calculated from the mass-balance and increasing the VOC weight percentage of the state average gas composition from 1.25% in the first analysis to 4.47% in the second analysis. The 51.9 tpy methane control threshold calculated from the state average gas composition is approximately 2% of the major modification facility threshold for GHG meaning it is appropriate to use it as a control threshold in the permit. However, as is shown in the analysis in Appendix D – Cost Analysis for Combustion Control Devices, control of methane at 51.9 tpy is not cost-effective.

The average gas composition determined in the second analysis is comparable to other sources such as E C/R Incorporated's memorandum¹⁴ to EPA, which was used in establishing the requirements of 40 CFR Part 60 Subparts OOOO and OOOOa. In most cases the cost-effectiveness threshold for methane control was determined to be \$1,000/ton of methane reduced, which is based on an analysis of EPA's technical support document for Subpart OOOOa where the cost-effectiveness threshold appeared to be \$1,000/ton based on which methane control techniques were implemented and which were not. The \$1,000/ton of methane reduced also coincides with the central estimate of the Social Cost of Methane as determined by EPA in 2012.

As shown in Appendix D – Cost Analysis for Combustion Control Devices, the BAT methane control is cost-prohibitive at \$2,239/ton of methane reduced when considering the 51.9 tpy calculated control threshold. Even though methane control is cost-effective at approximately 163 tpy methane based on the \$1,000/ton reduced threshold based on a linear interpolation, the 200 tpy BAT methane control threshold previously proposed is maintained for new or modified unconventional natural gas sources at \$581/ton of methane reduced. One reason for conservatively establishing the BAT methane control threshold is due to the scientific uncertainty inherent in any analysis, including the second analysis discussed above and in Appendix A – Average Gas Composition Analysis and the site-specific uncertainty in the control costs from Appendix D – Cost Analysis for Combustion Control Devices. BAT control measures for methane must be implemented for sources with emissions that meet or exceed 200 tpy methane; this requirement is also included in the exemption criteria for facilities seeking exemption under Category 38(c). For those sources that wish to forgo controls, they can use methods or techniques to reduce methane emissions below the BAT control threshold.

Another reason in establishing the BAT 200 tpy methane control threshold is that, according to the Air Emissions Inventory, between 2012 and 2016 various sources at natural gas production, compression, and processing facilities have emissions exceeding 200 tpy of methane. While the number of sources fluctuate, generally speaking the number of sources have increased from year to year; details are shown in Table 6.

Table 6 - Reported Methane Emissions Greater Than 200 tpy

Source	Number of Sources				
	2012	2013	2014	2015	2016
Pumps	9	12	5	8	22
Heaters				2	1
Pigging				2	
Blowdowns	4	6	14	25	17
Completions	52	10	1	6	11
Dehydrators	33	40	37	28	30

¹⁴ Memorandum on Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking, E C/R Incorporated, July 28, 2011.

Fugitive			3	9	7
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It should be noted, however, that even when not explicitly stated for control of methane, such as for sources that were constructed prior to August 8, 2018, the BMP, maintenance requirements, operating limitations, and control requirements often have a co-benefit of reducing methane emissions. As an illustration of this co-benefit, assume the 95% control requirement for VOC from a storage vessel authorized under Category Number 38(b) is met using an enclosed flare. Assuming a pre-control VOC emission rate of 10 tpy, the updated average gas composition as determined in Table 16 of Appendix A – Average Gas Composition Analysis, a methane destruction efficiency of 95%, and that 100% of the destroyed methane becomes CO₂, it is possible to calculate the greenhouse gas reduction in CO_{2e}. The following equation shows the amount of methane emissions that coincide with the 10 tpy VOC assumption:

$$\left| \frac{10 \text{ ton VOC}}{\text{year}} \right| \left| \frac{1 \text{ ton natural gas}}{0.0447 \text{ ton VOC}} \right| \left| \frac{0.8603 \text{ ton CH}_4}{1 \text{ ton natural gas}} \right| = 192.5 \text{ tpy CH}_4$$

The next calculation shows the amount of CO₂ generated by combusting the methane in the control device, using the 95% destruction efficiency and 100% conversion assumptions:

$$\left| \frac{192.5 \text{ tons CH}_4}{\text{year}} \right| \left| \frac{2000 \text{ lb CH}_4}{1 \text{ ton CH}_4} \right| \left| \frac{1 \text{ lb} \cdot \text{mol CH}_4}{16.04 \text{ lb CH}_4} \right| \left| \frac{0.95 \text{ lb} \cdot \text{mol CH}_4}{1 \text{ lb} \cdot \text{mol CH}_4} \right| \left| \frac{1 \text{ lb} \cdot \text{mol CO}_2}{1 \text{ lb} \cdot \text{mol CH}_4} \right| \left| \frac{44.02 \text{ lb CO}_2}{\text{lb} \cdot \text{mol CO}_2} \right| \left| \frac{1 \text{ ton CO}_2}{2000 \text{ lb CO}_2} \right|$$

= 501.8 tpy CO₂ produced from the combustion of methane

The final equation shows the total amount of CO_{2e} reduced by showing the amount of CO_{2e} equivalent to the reduced methane and subtracting the CO_{2e} of the CO₂ emissions produced in the combustion process:

$$(0.95)(192.5 \text{ tpy CH}_4) \left(\frac{25 \text{ tpy CO}_{2e}}{1 \text{ tpy CH}_4} \right) - (501.8 \text{ tpy CO}_2) \left(\frac{1 \text{ tpy CO}_{2e}}{1 \text{ tpy CO}_2} \right)$$

= 4,070.1 tpy CO_{2e} eliminated by the combustion of methane

Techniques for the control of methane emissions differ depending on whether they are due to venting, processing natural gas, or fugitive emissions. The primary control technique considered for the reduction of venting or process emissions is the installation of a closed vent system routed to a process or control. The primary control technique considered for the reduction of fugitive emissions is an LDAR program.

XIX. Sources Common to GP-5 and GP-5A

A. Glycol Dehydration Units and Associated Equipment

All natural gas well streams contain water vapor as they leave the reservoir, and this water is produced along with the natural gas. As the natural gas travels up the well bore, it cools as a result of pressure reduction and the conduction of heat through the casing to cooler formations. Therefore, since the ability of gas to hold water vapor decreases as the gas temperature decreases, natural gas is nearly always saturated with water vapor when it reaches surface equipment. Additional cooling of the saturated gas will cause the formation of free water. The process for removal of water vapor from natural gas is known as dehydration.

Dehydrators are designed to remove water from the natural gas vapor stream, thereby reducing corrosion and preventing the formation of hydrates, which are solid compounds that can cause flow restrictions and plugging in valves and even pipelines. The water-lean glycol usually flows downward in an absorption tower, counter-current to the natural gas. The glycol absorbs most of the water from the natural gas, but it also absorbs other materials present in the gas stream. The dried natural gas exits the top of the tower. The water-rich glycol leaves the bottom of the tower and flows to the regenerator. The regenerator heats the glycol to drive off water vapor, and the water vapor is usually vented directly to the atmosphere through the regenerator vent stack. While water has a boiling point of 212 degrees Fahrenheit, glycol does not boil until 400 degrees Fahrenheit. This difference in the boiling points allows for the easy removal of water from the glycol. The water-lean glycol is then returned to the absorber. Glycol has a high affinity for water and a relatively low affinity for non-aromatic hydrocarbons, which makes it a very good absorbent fluid for drying natural gas. However, the glycol does absorb small amounts of methane and other hydrocarbons from the natural gas. The hydrocarbons are released to the atmosphere along with the water vapor from the regenerator vent.

Some glycol dehydrators have additional equipment. Two common additions are flash tanks and regenerator vent emissions control equipment. The flash tank is placed in the rich glycol loop between the absorber and the regenerator. The glycol line pressure is dropped in the flash tank, causing most of the light hydrocarbons to flash into the vapor phase. The flash gas is usually routed to the regenerator burner as fuel. The methane emissions from the regenerator vent can be significantly reduced by using a flash tank. Regenerator vent control devices on units reduce emissions of BTEX and VOC to the atmosphere. These compounds are absorbed from the gas stream and driven off with the water in the regenerator vent. Control devices usually condense the water and hydrocarbons (containing BTEX and heavier VOC), then decant the hydrocarbons for sale and the water for disposal.

Emissions from glycol dehydration units are often controlled by using a condenser on the regenerator still vent and then venting to the atmosphere or to the regenerator firebox, other heaters, or a flare. Emissions from water-rich glycol flash tank vents are often controlled by combustion or by recycling back to low-pressure inlet gas streams. These systems have been shown to recover 90 to 99 percent of methane that would otherwise be flared into the atmosphere.¹⁵

1. Emission Limits for Glycol Dehydrators

a. Existing Glycol Dehydrators

The owner or operator of each existing glycol dehydrator located at an unconventional natural gas well site, remote pigging station, natural gas compression station, natural gas processing plant, or natural gas transmission station shall comply with the applicable requirements established in 40 CFR Part 63, Subpart HH, which are incorporated by reference in the General Permits. It is important to note that the locations listed in the technical support documents of 40 CFR Part 63, Subpart HH as urbanized areas and urban clusters were updated in the 2010 Census. The new list can be found in Appendix F.

The owner or operator of each existing glycol dehydrator installed prior to February 2, 2013, which has a total uncontrolled PTE of VOC in excess of 10 tpy, shall be controlled by at least 85% with a condenser, enclosed flare, or other air cleaning device approved by the Department.

The owner or operator of each existing glycol dehydrator installed on or after February 2, 2013, but before August 8, 2018 at a natural gas compression station or processing plant, which has a total

¹⁵ NaturalGas.org, last accessed on May 24, 2018.
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uncontrolled PTE of VOC in excess of 5 tpy, shall be controlled by at least 95% with a condenser, enclosed flare or other air cleaning device approved by the Department.

The owner or operator of each existing glycol dehydrator installed on or after August 10, 2013, but before August 8, 2018 at an unconventional natural gas well site or remote pigging station, which has a total uncontrolled VOC emission rate greater than or equal to 2.7 tpy, an uncontrolled single HAP emission rate greater than or equal to 0.5 tpy, or a total HAP emission rate greater than or equal to 1.0 tpy, shall be controlled by at least 95%.

b. New Glycol Dehydrators

The owner or operator of each new glycol dehydrator located at an unconventional natural gas well site, remote pigging station, natural gas compression station, processing plant, or transmission station shall comply with the applicable requirements established in 40 CFR Part 63, Subpart HH, which are incorporated by reference in the General Permits.

For new glycol dehydrators whose emissions are greater than or equal to the control thresholds for methane of 200 tpy, VOC of 2.7 tpy, single HAP of 0.5 tpy, **or** combined HAP of 1.0 tpy, emission must be controlled by at least 95%. A cost analysis was done by the Department for sources that emit above the control thresholds and included in Appendix D – Cost Analysis for Combustion Control Devices. A revised analysis was done based on comments received and is also included in Appendix D – Cost Analysis for Combustion Control Devices. The control requirements are summarized in Table 7.

Table 7 - Glycol Dehydrator Control Thresholds and Control Requirements

Uncontrolled VOC PTE	Still Vent Control Level
Permitted Under GP-5 Prior to Feb 2, 2013	
>10 tpy	85%
Permitted Under GP-5 On or After Feb 2, 2013 but Prior to Aug 8, 2018	
>5 tpy	95%
Permitted on or After Aug 8, 2018	
≥2.7 tpy	95%

B. Stationary Natural Gas-Fired Spark Ignition Internal Combustion Engines

In an engine, a mixture of air and fuel is burned within the engine cylinder and the energy of expanding gases is converted into mechanical work at the engine crank shaft. The relative proportions of air and fuel in the combusted mixture is called the air-to-fuel (A/F) ratio. The A/F ratio is called "stoichiometric" if the mixture contains the precise amount of air that supplies sufficient oxygen for complete combustion of the fuel with no oxygen or fuel left over after combustion.

Reciprocating engines are grouped into two general categories based on the combustion model used in their design: "rich-burn" and "lean-burn." The primary distinction between the two is the amount of excess air admitted prior to combustion. Rich-burn engines operate with a minimum amount of air required for combustion and lean-burn engines use 50% to 100% more air than is necessary for combustion.

In the natural gas industry, engines are used as prime movers to drive compressors or vapor recovery units and as electric generators. Both rich-burn and lean-burn engines are used in the natural gas industry.

1. Emissions from Lean-Burn and Rich-Burn Engines

The main pollutants emitted from the exhaust of SI-RICE are NO_x, CO, NMNEHC, formaldehyde, SO_x, PM, and methane, depending on the composition of the fuel used. Natural gas is the only fuel authorized by GP-5A and GP-5.

2. Emission Control Technology

Control technologies that may be used on engines primarily fall into two categories, combustion control and post-combustion control.

a. Combustion Control

Control of combustion temperature is the principal focus of combustion process control in natural gas-fired engines. Combustion control requires tradeoffs – higher temperatures favor complete consumption of the fuel and lower residual hydrocarbons and CO but result in increased NO_x formation. Lean combustion dilutes the fuel mixture and reduces combustion temperatures and therefore reduces NO_x formation. This allows a higher compression ratio or peak firing pressures resulting in higher efficiency. However, if the mixture is too lean, misfiring and incomplete combustion may occur, increasing CO and VOC emissions.¹⁶

Because the NO_x produced by SI-RICE is primarily thermal NO_x, reducing the combustion temperature will result in less NO_x production. Thus, the most common strategy for NO_x control is to control the combustion temperature. This is most easily done by adding more air than what is required for complete combustion of the fuel. This raises the heat capacity of the gases in the cylinder so that for a given amount of energy released in the combustion reaction, the maximum temperature will be reduced.

Combustion temperature can also be controlled to some extent in reciprocating engines by one or more of the following techniques:

- Diluting the fuel-air mixture with exhaust gas recirculation (EGR), which replaces some of the air and contains water vapor that has a relatively high heat capacity and absorbs some of the heat of combustion.
- Modifying valve timing, compression ratio, turbocharging, and the combustion chamber configuration.

b. Post-Combustion Emission Reduction Technology for Rich-Burn Engines

i. Three-Way Catalyst (for NO_x, CO, and NMNEHC reduction)

In rich-burn engines, an after-treatment system such as NSCR, also known as a three-way catalyst, can be added to reduce NO_x, CO, and NMNEHC emission levels. Three-way catalysts use oxygen to treat exhaust emissions. However, three-way catalysts do not use unburned combustion oxygen to reduce emissions. They make use of the oxygen within the constituent compounds. Oxygen from NO_x is used

¹⁶ Technical Report: Technology Characterization: Reciprocating Engines, March 2015, Prepared by Darrow, K. *et al.*, of ICF International on behalf of the EPA and US DOE.

to oxidize the CO and NMNEHC. This converts the three pollutants into N₂, CO₂ and H₂O. Catalysts may be used in series to obtain lower emission levels. Typically, the reduction level for NO_x is > 95%, CO is >95%, and NMNEHC is >50%. For this analysis, the Department has determined that an NSCR is economically feasible for engines if the cost per ton of NO_x, CO, and NMNEHC removal is approximately \$5,000; see Appendix C – Oxidation Catalyst and NSCR Cost Analysis for Engines and Turbines.

c. Post-Combustion Emission Reduction Technology for Lean-Burn Engines

i. Oxidation Catalyst (for CO and NMNEHC reduction)

On lean-burn engines, oxidation catalysts using platinum and palladium are effective for lowering CO and NMNEHC levels in exhaust emissions. Methane that is not combusted in the engine is exhausted with the other products of combustion; however, methane is difficult to oxidize at exhaust temperatures provided by lean-burn engines. Therefore, the control efficiency for methane using an oxidation catalyst can be very low, and no specific emission limit for methane is included in the final General Permits for engines. No A/F ratio control system is required with this type of catalyst and it can be applied to either rich-burn or lean-burn engines. For this analysis, the Department has determined that an oxidation catalyst is economically feasible for engines if the cost per ton of CO and NMNEHC removal is approximately \$5,000; see Appendix C – Oxidation Catalyst and NSCR Cost Analysis for Engines and Turbines.

ii. Selective Catalytic Reduction (for NO_x reduction)

SCR is an exhaust gas after-treatment that specifically targets the NO_x in engine exhaust and converts it to N₂ and H₂O. Unlike the three-way catalyst which uses oxygen from the exhaust stream to treat emissions, SCR injects a compound into the exhaust stream to start the reaction. The process begins when a small amount of urea is injected into the exhaust stream. After hydrolysis, the urea becomes ammonia and reacts with NO_x. On closed-loop control systems SCR can reduce natural gas-fired engine NO_x emissions by 90% as per the SCR system manufacturers.¹⁷

In the GP-5 issued on February 2, 2013, the Department required add-on control for CO emissions which also controls VOC and HCHO emissions. The Department also established an uncontrolled NO_x emission limit of 0.5 grams per brake horsepower-hour (g/bhp-h) for lean-burn engines rated at greater than 500 brake horsepower (bhp) based on vendor's guaranteed emission rates. The Department evaluated the economic feasibility of SCR for engines and determined that SCR is economically cost-prohibitive for engines rated below 4,000 bhp. The Department did not evaluate SCR for larger engines at that time because the information received from natural gas compression facility owners led us to believe that the typical engine sizes were between 1,300 bhp and 4,000 bhp.

The Department has reviewed the manufacturers' current guaranteed level for NO_x emissions for lean-burn engines and found that some manufacturers now offer a guaranteed emissions rate of 0.30 g/bhp-h NO_x for certain engines rated greater than or equal to 1,875 bhp. For the current analysis, the Department has determined that SCR is economically feasible for engines if the cost per ton of NO_x removal is approximately \$10,000; see the updated Appendix B – SCR Cost Analysis for Engines and Turbines.

¹⁷ Emails from Vendor A and Vendor B, as referenced in Appendix B – SCR Cost Analysis for Engines and Turbines of this document.

3. Engine Size Grouping

The Department chose the engine size groups based on information for various engine makes and models available. The General Permits group the engines into the following categories:

- Less than 100 bhp;
- Greater than or equal to 100 bhp and less than 500 bhp;
- Greater than or equal to 500 bhp and less than 2,370 bhp; and
- Greater than or equal to 2,370 bhp.

The groupings are comparable to the bhp categories in 40 CFR Part 60, Subpart JJJJ. The Department made BAT determinations for these categories.

4. Engine Emission Limits

The BAT for most of the engine size categories in the proposed GP-5A and GP-5 is adapted from the current GP-5 for Natural Gas Compression and/or Processing Facilities, revised January 16, 2015. For engines rated above a certain size, the Department evaluated uncontrolled emissions, control efficiency of various controls and associated costs, and stack test results for SI-RICE to establish BAT.

It should be noted that there were engines permitted through GP-5 prior to February 2, 2013, which could include sources at natural gas well sites. The scope of the revised GP-5, issued on February 2, 2013, did not include sources at natural gas well sites. Therefore, specific categories for these existing engines authorized to operate under previous versions of GP-5 and their emissions limits have been included in GP-5A.

a. Rich-Burn Engines Less Than 100 bhp

Due to the limited available emissions data for rich-burn engines less than 100 hp, the Department determined BAT for rich-burn engines less than 100 bhp equivalent to the emissions standards specified in 40 CFR Part 60 Subpart JJJJ. The emission limits included in the final General Permits are 1.0 g/bhp-h of NO_x, 2.0 g/bhp-h of CO, and 0.70 g/bhp-h of NMNEHC.

b. Rich-Burn Engines Greater Than or Equal To 100 bhp but Less Than 500 bhp

Vendor data for rich-burn engines greater than or equal to 100 bhp but less than 500 bhp indicate weighted average emission rates¹⁸ of 15.9 g/bhp-h for NO_x, 8.3 g/bhp-h for CO, 1.5 g/bhp-h for THC, and 0.3 g/bhp-h for NMNEHC. Both the weighted average emission rates and BAT emission rates were used in the BAT analysis.

All NSCR cost estimations were based on an analysis by E^{C/R} Incorporated¹⁹, where they determined total annual costs based on vendor data. The equations are for retrofitted technology and give the cost in 2009 dollars. The total annual cost in the cost analysis was then multiplied by the consumer price index (CPI) of 1.12 for inflating 2009 dollars to 2016 dollars. Because the equations were designed as a retrofit, it is assumed that it is a conservative cost estimate for new installations. It was assumed that the control efficiencies for NO_x and CO are 95% and for NMNEHC is 50%.

¹⁸ The weighted average emission rates for all engine categories is based on data gathered by the Department and included in the Excel Spreadsheet titled GP-5 NG Engine Data 03152018.

¹⁹ Memorandum on Control Costs for Existing Stationary SI-RICE, E^{C/R} Incorporated, June 29, 2010.

Using the weighted average emission rates and the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for rich-burn engines greater than or equal to 100 bhp but less than 500 bhp is estimated between \$138 and \$11,480 per ton of pollutants reduced. The \$11,480 per ton of pollutants reduced figure is for a 100 hp engine operating at the BAT emissions rate, which presumes installation of NSCR. Discarding this point, the control cost for an NSCR is then estimated to be between \$138 and \$5,126 per ton of pollutant reduced, which are within the cost-effectiveness benchmark (~\$5,000/ton of pollutant removed). Therefore, the Department determines NSCR to be BAT for rich-burn engines greater than or equal to 100 bhp but less than 500 bhp where emission limits of 0.25 g/bhp-h for NO_x, 0.30 g/bhp-h for CO, and 0.20 g/bhp-h for NMNEHC remains as in the previously issued GP-5.

c. Rich-Burn Engines Greater Than or Equal To 500 bhp

Vendor data for rich-burn engines greater than or equal to 500 bhp indicate uncontrolled weighted average emission rates of 15.4 g/bhp-h for NO_x, 8.2 g/bhp-h for CO, 1.7 g/bhp-h for THC, and 0.3 g/bhp-h for NMNEHC. Both the weighted average emission rates and BAT emission rates were used in the BAT analysis.

Using the weighted average emission rates and the BAT emissions rates, the assumed control efficiencies, and assuming full-year operation, the control cost for rich-burn engines greater than or equal to 500 bhp is estimated between \$30 and \$3,256 per ton of pollutants reduced, which are within the cost-effectiveness benchmark (~\$5,000/ton of pollutant removed). Therefore, the Department determines NSCR to be BAT for rich-burn engines greater than or equal to 500 bhp where emission limits of 0.20 g/bhp-h for NO_x, 0.30 g/bhp-h for CO, and 0.20 g/bhp-h for NMNEHC remains as in the previously issued GP-5.

d. Lean-Burn Engines Less Than 100 bhp

Due to the limited available emissions data for lean-burn engines less than 100 hp, the Department determined BAT for lean-burn engines less than 100 bhp equivalent to the emissions standards specified in 40 CFR Part 60 Subpart JJJJ. The emission limits included in the final General Permits are 1.0 g/bhp-h of NO_x, 2.0 g/bhp-h of CO, and 0.70 g/bhp-h of NMNEHC.

e. Lean-Burn Engines Greater Than or Equal To 100 bhp but Less Than 500 bhp

Vendor data for lean-burn engines greater than or equal to 100 bhp but less than 500 bhp indicate uncontrolled weighted average emission rates of 7.8 g/bhp-h for NO_x, 6.7 g/bhp-h for CO, 1.9 g/bhp-h for THC, and 0.6 g/bhp-h for NMNEHC. Both the weighted average emission rates and BAT emission rates were used in the BAT analysis.

Using the weighted average emission rates and BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for an oxidation catalyst for lean-burn engines greater than or equal to 100 bhp but less than 500 bhp is estimated between \$286 and \$1,956 per ton of pollutants reduced, which are within the cost-effectiveness benchmark (~\$5,000/ton of pollutant removed). Therefore, the Department determines oxidation catalyst to be BAT for lean-burn engines greater than 100 bhp but less than 500 bhp with emission limits of 0.70 g/bhp-h for CO and 0.30 g/bhp-h for NMNEHC based on the weighted average emission factors and the given control efficiencies.

In the previous analysis, using the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for lean-burn engines greater than or equal to 100 bhp but

less than 500 bhp is estimated between \$25,843 and \$62,940 per ton of NO_x reduced. In the revised analysis, using the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for lean-burn engines greater than or equal to 100 bhp but less than 500 bhp is estimated between \$22,183 and \$71,821 per ton of NO_x reduced. The Department maintains the determination that SCR is not BAT for lean-burn engines greater than or equal to 100 bhp but less than 500 bhp because it is not economically feasible; therefore, the Department established emission limit of 1.00 g/bhp-h NO_x remains as in the previously issued GP-5.

f. Lean-Burn Engines Greater Than or Equal To 500 bhp but Less Than 2,370 bhp

Vendor data for lean-burn engines greater than or equal to 500 bhp but less than 2,370 bhp indicate uncontrolled weighted average emission rates of 1.4 g/bhp-h for NO_x, 2.0 g/bhp-h for CO, 4.0 g/bhp-h for THC, and 0.5 g/bhp-h for NMNEHC. Both the weighted average emission rates and the current uncontrolled BAT for NO_x were used in the BAT analysis.

In the previous analysis, using the weighted average emission rates and BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for an oxidation catalyst for lean-burn engines greater than or equal to 500 bhp but less than 1,875 bhp is estimated between \$232 and \$2,081 per ton of pollutants reduced. Under the new category, using the previous analysis, the control cost for an oxidation catalyst for lean-burn engines greater than or equal to 500 bhp but less than 2,370 bhp is estimated between \$185 and \$2,081 per ton of pollutants reduced, which are within the cost-effectiveness benchmark (~\$5,000/ton of pollutant removed). Therefore, the Department maintains the determination that oxidation catalyst is BAT for engines greater than 500 bhp but less than 2,370 bhp with an emission limit of 0.25 g/bhp-h for CO based on the weighted average emission factor and the given control efficiencies and an emission limit of 0.25 g/bhp-h for NMNEHC as in the previously issued GP-5.

In the previous analysis, using the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for lean-burn engines greater than or equal to 500 bhp but less than 1,875 bhp is estimated between \$10,466 and \$13,477 per ton of NO_x reduced. In the revised analysis, using the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for lean-burn engines greater than or equal to 500 bhp but less than 2,370 bhp is estimated between \$11,792 and \$24,541 per ton of NO_x reduced. Therefore, the Department determines that SCR is not BAT for lean-burn engines greater than or equal to 500 bhp but less than 2,370 bhp because it is not economically feasible, and the emission limit remains 0.50 g/bhp-h for NO_x as in the previously issued GP-5.

g. Lean-Burn Engines Greater Than or Equal To 2,370 bhp

Vendor data for lean-burn engines greater than or equal to 2,370 bhp indicate uncontrolled weighted average emission rates of 0.7 g/bhp-h for NO_x, 2.1 g/bhp-h for CO, 5.7 g/bhp-h for THC, and 0.8 g/bhp-h for NMNEHC.

In the previous analysis, using the weighted average emission rates and BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for an oxidation catalyst for lean-burn engines greater than or equal to 1,875 bhp is estimated between \$123 and \$873 per ton of pollutants reduced. Under the new category, using the previous analysis, the control cost for an oxidation catalyst for lean-burn engines greater than or equal to 2,370 bhp is estimated between \$123 and \$781 per ton of pollutants reduced, which are within the cost-effectiveness benchmark (~\$5,000/ton of pollutant removed). Therefore, the Department determined oxidation catalyst to be BAT for lean-

burn engines greater than 2,370 bhp with an emission limit of 0.25 g/bhp-h for CO based on the weighted average emission factor and the given control efficiency and an emission limit of 0.25 g/bhp-h for NMNEHC as in the previously issued GP-5.

In the previous analysis, using the BAT emission rate of 0.50 g/bhp-h as baseline, the assumed control efficiency, and assuming full-year operation, the control cost effectiveness for SCR for lean-burn engines greater than 1,875 bhp was estimated to be less than \$8,818 per ton of NO_x reduced. In the revised analysis, lean-burn engines rated below 2,370 bhp were included in the previous category. However, the Department learned in recent conversations with Caterpillar that engines rated at 1,875 bhp are from a special class of engine designed to emit 0.30 g NO_x/bhp-h. Engines of the same model designation, but not of the same class as the 1,875 bhp model, are rated at 1,775 bhp. SCR is estimated to be \$11,792 per ton of NO_x reduced for the 1,775 bhp model and \$19,178 per ton of NO_x reduced for the 1,875 bhp model, therefore, SCR is a cost-prohibitive option for lean-burn engines designed to emit 0.30 g NO_x/bhp-h. This was one reason for changing the engine categories.

The Department previously relied on stack test data that shows that approximately 33% of engines rated greater than or equal to 1,875 bhp are capable of achieving a NO_x emissions rate of 0.35 g/bhp-h uncontrolled. Therefore, the Department performed the previous analysis using 0.35 g/bhp-h of NO_x as a baseline, the assumed control efficiency, and assuming full-year operation, and found the control cost effectiveness for SCR for lean-burn engines rated greater than or equal to 1,875 bhp but less than 3,000 bhp is estimated to increase to between \$10,241 and \$12,597. The control cost effectiveness for SCR for engines rated greater than or equal to 3,000 bhp, using a NO_x emissions rate of 0.35 g/bhp-h as the baseline, the assumed control efficiency, and assuming full-year operation, is estimated to be less than \$9,064. The Department therefore determined that lean-burn engines greater than or equal to 1,875 bhp but less than 3,000 bhp would have a dual BAT where engines with a NO_x emission rate of 0.50 g/bhp-h required SCR and engines with a NO_x emission rate of 0.35 g/bhp-h did not require SCR based on economic feasibility. However, as many of the commentators pointed out, relying on stack test data to establish an uncontrolled emission rate based on 33% of sources tested basically means that two in three engines, or an engine in two out of three tests, would be incapable of meeting that emission rate. This was another reason for changing the engine categories.

The Department conducted a revised analysis based on available engine models. For engines with a NO_x emission rate of 0.50 g/bhp-h, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for lean-burn engines greater than or equal to 2,370 bhp is estimated between \$7,611 and \$10,451 per ton of NO_x reduced. This was the final reason for changing the engine categories.

For engines with a NO_x emission rate of 0.30 g/bhp-h, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for lean-burn engines greater than or equal to 2,370 bhp is estimated between \$13,706 and \$17,072 per ton of NO_x reduced. The Department therefore determined that lean-burn engines greater than or equal to 2,370 bhp have a dual BAT where engines with a NO_x emission rate of 0.50 g/bhp-h require SCR and engines with a NO_x emission rate of 0.30 do not require SCR based on economic feasibility. Based on the comments received, the Department has revised the ammonia slip limit to 10 ppmvd corrected to 15% O₂ in the final general permits.

The BAT emission limits for the proposed General Permits are summarized in Table 8 and Table 9.

Table 8 - BAT Emission Limits for Existing SI-RICE

Engine Type	Rated bhp	NO _x	CO	NMNEHC as propane (excluding HCHO)	HCHO
Permitted Under GP-5 Prior to Feb 2, 2013					
NG-fired Lean- and Rich-Burn Engines	<1,500	2.0 g/bhp-h	2.0 g/bhp-h	2.0 g/bhp-h	
Permitted Under GP-5 On or After Feb 2, 2013 but Prior to Aug 8, 2018					
NG-fired Lean- and Rich-burn Engines	≤100	2.0 g/bhp-h	2.0 g/bhp-h	-	-
NG-fired Lean-burn Engines	>100 to ≤500	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h	-
NG-fired Lean-burn Engines	>500	0.50 g/bhp-h	47 ppmvd @ 15% O ₂ <u>or</u> 93% reduction	0.25 g/bhp-h	0.05 g/bhp-h
NG-fired Rich-burn Engines	>100 to ≤500	0.25 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	
NG-fired Rich-burn Engines	>500	0.20 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	2.7 ppmvd @ 15% O ₂ <u>or</u> 76% reduction

Table 9 - Proposed BAT Emission Limits for New SI-RICE

Engine Type	Rated bhp	NO _x	CO	NMNEHC as propane (excluding HCHO)	HCHO
Permitted on or After Aug 8, 2018					
New NG-fired Lean-burn Engines	≤100	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h	-
New NG-fired Lean-burn Engines	>100 to ≤500	1.0 g/bhp-h	0.70 g/bhp-h	0.30 g/bhp-h	-
New NG-fired Lean-burn Engines	>500 to <2,370	0.50 g/bhp-h	0.25 g/bhp-h	0.25 g/bhp-h	0.05 g/bhp-h
New NG-fired Lean-burn Engines	≥2,370	0.30 g/bhp-h Uncontrolled or 0.05 g/bhp-h with Control	0.25 g/bhp-h	0.25 g/bhp-h	0.05 g/bhp-h
New NG-fired Rich-burn Engines	≤100	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h	-
New NG-fired Rich-burn Engines	>100 to ≤500	0.25 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	
New NG-fired Rich-burn Engines	>500	0.20 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	2.7 ppmvd @ 15% O ₂ or 76% reduction

In addition, the engines shall comply with all applicable requirements specified in 40 CFR Part 60, Subpart JJJJ and 40 CFR Part 63, Subpart ZZZZ. For engines constructed on or after June 12, 2006, compliance with the requirements in Table 10 guarantees compliance with the requirements of 40 CFR Part 60 Subpart JJJJ and 40 CFR Part 63 Subpart ZZZZ.

Table 10 - 40 CFR Part 60 Subpart JJJJ Requirements

Engine Size	Manufacture Date	NO _x	NMNEHC (as propane) excluding HCHO	CO
≤25 bhp and <225 cc displacement	7/1/2008	12 g/bhp-h		387 g/bhp-h
	1/1/2012	7.5 g/bhp-h		455 g/bhp-h
≤25 bhp and ≥225 cc displacement	7/1/2008	10. g/bhp-h		387 g/bhp-h
	1/1/2011	6.0 g/bhp-h		455 g/bhp-h
25 bhp < ER < 100 bhp	1/1/2007	2.8 g/bhp-h		4.9 g/bhp-h
	1/1/2011	1.0 g/bhp-h	0.70 g/bhp-h	2.0 g/bhp-h
100 hp ≤ ER < 500 bhp	7/1/2008	2.0 g/bhp-h	1.0 g/bhp-h	4.0 g/bhp-h
	1/1/2011	1.0 g/bhp-h	0.70 g/bhp-h	2.0 g/bhp-h
≥500 bhp	7/1/2007	2.0 g/bhp-h	1.0 g/bhp-h	4.0 g/bhp-h
	7/1/2010	1.0 g/bhp-h	0.70 g/bhp-h	2.0 g/bhp-h

The Department's proposed BAT requirements are at least as or more stringent than those listed in the table above. Therefore, by complying with the Department's BAT requirements, the owner or operator of an engine will be guaranteed compliant with the applicable emission limits of 40 CFR Part 60 Subpart JJJJ and 40 CFR Part 63 Subpart ZZZZ for new engines.

For engines constructed prior to June 12, 2006, compliance with the requirements in Table 11 guarantees compliance with the requirements of 40 CFR Part 63 Subpart ZZZZ:

Table 11 - 40 CFR Part 63 Subpart ZZZZ Requirements

Engine Category	Oil and Filter Change	Spark Plug Inspection, Plugs Replaced as Necessary	Hose Inspection, Hoses Replaced as Necessary
Emergency SI-RICE; 4SRB and 4SLB > 500 hp that operate ≤ 24 hours per year	500 hours or annually	1,000 hours or annually	500 hours or annually
4SRB and 4SLB > 500 hp in remote locations	2,160 hours or annually	2,160 hours or annually	2,160 hours or annually
4SLB > 500 hp	Install Oxidation Catalyst to Reduce HAP Emissions		
4SRB > 500 hp	Install NSCR to Reduce HAP Emissions		
4SRB and 4SLB ≤ 500 hp	1,440 hours or annually	1,440 hours or annually	1,440 hours or annually
2SLB	4,320 hours or annually	4,320 hours or annually	4,320 hours or annually

Visible emissions shall not meet or exceed 10% opacity for a period or periods aggregating more than three minutes in any one hour nor meet or exceed 30% opacity at any time.

C. Reciprocating Natural Gas Compressors

Fluids, such as natural gas, travel naturally from areas of high pressure to areas of low pressure. Natural gas compressors take advantage of this property by increasing the pressure of natural gas at one location in a pipeline in order to promote the movement of the gas to a lower pressure area downstream. The pipeline pressure tends to drop over the length of a pipeline due to friction. This decrease in pressure is the reason why compression stations are located along the length of the pipeline.

Reciprocating natural gas compressors provide this increase of pressure by using a piston and cylinder arrangement. As the piston moves through the chamber, the pressure at the forward edge of the piston is increased as the volume in the cylinder is decreased. The high-pressure gas is then forced through a valve into the high-pressure section of the pipeline. On the reverse stroke, the pressure at the trailing edge of the piston is decreased as the volume in the cylinder is increased. This reduction in pressure allows the low-pressure gas in the pipeline to be drawn into the cylinder. The piston is connected to its prime mover by a rod, and the rod utilizes rod packings to reduce wear on the compressor components and to seal in the gas pressure. Over time, these packings can wear, resulting in methane, VOC, and HAP emissions.

It is not typical for reciprocating compressors to be installed at an unconventional natural gas well site. According to 40 CFR Part 60, Subparts OOOO and OOOOa, reciprocating compressors located at well sites are not affected facilities. Since reciprocating compressors located at well sites are air contaminant sources subject to BAT requirements, the final GP-5A requires reciprocating compressors located at well sites to meet the same requirements for reciprocating compressors located at compression stations as BAT; see Appendix H – Well Site Rod Packing Replacement Cost-Effectiveness Analysis.

1. Existing Reciprocating Natural Gas Compressors

40 CFR Part 60, Subpart OOOO provides two options for controlling VOC emissions from reciprocating natural gas compressors. The first is to replace the rod packings either every 26,000 hours of operation (operating hours must be monitored and documented) or every 36 months (monitoring and documentation of operating hours not required). The second is to utilize a rod packing emissions collection system that operates under negative pressure to route the rod packing emissions to a process through a closed vent system.

The previous GP-5 required the owner or operator of reciprocating compressors to meet the requirements of 40 CFR Part 60, Subpart OOOO. Therefore, the owner or operator of an existing reciprocating natural gas compressor shall continue to comply with the applicable requirements specified in 40 CFR Part 60, Subpart OOOO, which are incorporated by reference in the General Permit.

2. New Reciprocating Natural Gas Compressors

EPA finalized NSPS OOOOa on June 3, 2016, which requires reciprocating natural gas compressors to replace the rod packing on or before 26,000 hours of operation or 36 calendar months or route emissions from the rod packing to a process through a closed vent system under negative pressure. Based on the Department's evaluation, no additional requirements are needed. Therefore, the Department determines that the recently promulgated requirements of 40 CFR Part 60, Subpart OOOOa are determined to be BAT. Therefore, the owner or operator of a new reciprocating natural gas compressor at natural gas compression stations, processing plants, and transmission stations shall comply with the applicable requirements specified in 40 CFR Part 60, Subpart OOOOa, which are incorporated by reference in the GP-5.

The Department examined whether the rod-packing replacement requirements of 40 CFR Part 60, Subpart OOOOa could also be applied to reciprocating compressors at unconventional natural gas well sites. Reciprocating compressors at these facilities are exempt based on EPA's determination in their Technical Support Document for Subpart OOOOa.²⁰ In their TSD, EPA determined that the cost to replace the rod-packings is \$1,620 per cylinder in 2008 dollars. Adjusting to 2016 dollars using the CPI, using EPA's base assumptions for emissions and number of cylinders, and assuming 7% for future worth calculations, the Department calculates that the cost per ton of methane reduced and cost per ton of pollutant reduced is \$15,802 and \$12,365, respectively, based on the 0.271 scf/h emission factor from the TSD.

However, a more recent study by the University of Texas²¹ (UT) lists compressor seal emission factors from different sources in Table 1-4 on pages 16 and 17 of the report including calculated emission factors from measurements conducted during the study. Table 1-4 of UT's report also includes EPA's methane emission factor of 0.271 scf/h for production sources, a natural gas emission factor of 0.343 scf/h per cylinder calculated from the methane emission factor using a default methane content of 78.8 mol%, and a natural gas emission factor of 42.2 scf/h per cylinder from a 1992 study by Picard. The UT study found the average rod packing emissions to be 241 Mscf/year, which translates to 27.5 scf/h per cylinder.

In Appendix H – Well Site Rod Packing Replacement Cost-Effectiveness Analysis, the costs associated with rod-packing replacement requirements identical to those in EPA's TSD for 40 CFR Part 60, Subpart OOOOa were reevaluated for unconventional natural gas well sites based on the additional natural gas emission factors from the UT study. Based on the emissions estimate using average emissions from the UT study, the requirement of rod-packing replacement was determined to be cost effective as BAT. The Center for Responsible Shale Development (CRSD) certifies participants, which includes energy companies such as Chevron, CNX, EQT, and Shell Appalachia, that conform to their performance standards. CRSD standard #14 also requires rod-packing replacement every 36 months or every 26,000 hours of operation at all new and existing sites, including those at the wellhead. The voluntary participation of natural gas producers in the CRSD performance standards supports the Department's determination that the rod-packing replacement requirement is technically and economically feasible and therefore BAT.

D. Storage Vessels

Storage vessels are used to collect and store condensate (also known as natural gas liquids or NGLs) and/or produced water that are byproducts of natural gas production. Most storage vessels in the natural gas industry are fixed-roof structures and are equipped with a variety of pressure equalization devices to protect the structural integrity of the tank.

There are several federal regulations that pertain to storage vessels including requirements found in 40 CFR Part 60, Subparts K, Ka, Kb, OOOO, and OOOOa and 40 CFR Part 63, Subpart HH. In addition, state regulations found in 25 Pa. Code §§ 129.56 and 129.57 have applicable requirements. 40

²⁰ E C/R Incorporated/US Environmental Protection Agency. Oil and Natural Gas Sector: Standards for Crude Oil and Natural Gas Facilities. Background Technical Support Document for the Proposed Standards 40 CFR Part 60, Subpart OOOOa. August 2015.

²¹ URS Corporation/University of Texas at Austin. 2011. Natural Gas Industry Methane Emission Factor Improvement Study, Final Report. December 2011. https://dept.ceer.utexas.edu/ceer/GHG/files/FReports/XA_83376101_Final_Report.pdf, last accessed May 24, 2018.

CFR Part 60, Subparts OOOO and OOOOa include inspection and monitoring requirements for storage vessels which are incorporated in the final General Permits by reference.

1. Emission Limits for Storage Vessels

a. Existing Storage Vessels

Existing storage vessels at crude oil and natural gas production (except unconventional natural gas facilities constructed on or after August 10, 2013 but prior to August 8, 2018), transmission, and distribution facilities constructed on or after August 23, 2011, but prior to August 8, 2018, with uncontrolled potential VOC emissions greater than or equal to 6.0 tpy are required to be controlled by 95% or more, install a fixed-roof tank with an internal floating roof, an external floating roof, or maintain the actual uncontrolled VOC emissions below 4.0 tpy as required by 40 CFR Part 60 Subparts OOOO and OOOOa.

Existing storage vessels at unconventional natural gas facilities constructed on or after August 10, 2013 but prior to August 8, 2018 are required to meet the conditions in Category 38(b) of the Air Quality Permit Exemptions document. This means that existing storage vessels at unconventional natural gas well sites shall be equipped with controls achieving VOC emission reductions of 95% or greater unless the facility's uncontrolled VOC emissions for all sources are below 2.7 tpy. If the storage vessels' HAP emissions are uncontrolled, they must also be included in the facility-wide uncontrolled single HAP emissions limit of 0.5 tpy and total uncontrolled HAP emissions limit of 1.0 tpy. The facility-wide uncontrolled emission limits do not include emissions from any source that is equipped with emission controls.

In addition, the owner or operator of any storage vessel, without regard to when it was constructed, must meet the applicable requirements of 25 Pa. Code §§129.56 and 129.57, which are incorporated by reference in the General Permits.

b. New Storage Vessels

Storage vessels at unconventional natural gas well sites constructed on or August 8, 2018, must meet the requirements of Category 38(c) of the Air Quality Permit Exemptions document.

Because the Department has not issued any plan approval for sources located at any unconventional natural gas well site, either the VOC and HAP emissions from each storage vessel installed at well sites on or after August 10, 2013 are below the control threshold requirement or emissions are being reduced by 95% or more. Therefore, based on the updated cost analysis in Appendix D – Cost Analysis for Combustion Control Devices and the lack of plan approvals for sources located at any unconventional natural gas well site, the Department has determined BAT for the General Permits to be the reduction of methane, VOC, and HAP emissions by 95% or more for a storage vessel that exceeds any control threshold of 200 tpy methane, 2.7 tpy VOC, 0.5 tpy of a single HAP, or 1.0 tpy of total HAP.

In addition, the owner or operator of any storage vessel, without regard to when it was constructed, must meet the applicable requirements of 25 Pa. Code §§129.56 and 129.57, which is incorporated by reference in the General Permits.

E. Tanker Truck Load-Out Operations

The storage tanks at unconventional natural gas well sites, natural gas compression facilities, and natural gas processing facilities must be unloaded on occasion. This is done by loading the liquids from the

tanks into tanker trucks so the liquids may be transported to a processing facility. The unloading process may emit methane, VOC, and HAP based on the composition of the liquids.

Since August 10, 2013, in accordance with Category 38 of the Air Quality Permit Exemptions document tanker truck load out operations are required to be equipped with controls achieving VOC, and HAP emissions reductions of 95% or greater unless their uncontrolled VOC, single HAP, and total HAP emissions are below the control thresholds of 2.7 tpy, 0.5 tpy, and 1.0 tpy, respectively. Because the Department has not issued any plan approval for tanker truck load out operations, either VOC and HAP emissions from each tanker truck load out operation on or after August 10, 2013 is below the control threshold requirement or emissions are being reduced by 95% or more.

All tanker truck load-out operations were required to use a vapor recovery load-out system that meets the closed vent system requirements in Section N, Enclosed Flares and Other Control Devices, in the originally proposed General Permits. This was an error, which was pointed out by several commentators, as there should be no requirement to use a vapor recovery load-out system for tanks that handle produced water. This was not the Department's intent, and to be consistent with Exemption 38 and the Internal Implementation Instructions for Exemption Category No. 38, a source that is below the control thresholds is not required to install controls.

Therefore, in the final General Permits, only tanker truck load-out operations that take liquids from storage vessels with emissions above the control thresholds are required to use a vapor balancing system and ensure each truck used to unload liquids has passed one of the annual leak checks below.

When calculating the emissions from tanker truck load-out operations, the collection efficiency may be assumed to be 99.2% for tanker trucks that pass the MACT-level annual leak test and 98.7% for tanker trucks that pass the NSPS-level annual test. The MACT-level leak test is passed if the tanker does not indicate more than a 1" H₂O pressure change within 5 minutes after being pressurized to 18" H₂O and after being depressurized to 6" H₂O vacuum. The NSPS-level leak test is passed if the tanker does not indicate more than a 3" H₂O pressure change within 5 minutes after being pressurized to 18" H₂O and after being depressurized to 6" H₂O vacuum. A leak test performed in accordance with 49 CFR §180.407 – *Requirements for Test and Inspection of Specification Cargo Tanks*, or EPA Method 27 – *Determination of Vapor Tightness of Gasoline Delivery Tank Using Pressure Vacuum Test*, will be accepted as equivalent to an NSPS-level collection efficiency (i.e., 98.7%).

Originally, the Department required the owner or operator to keep records of the entire fleet of tanker trucks that collect liquids from the facility, including the date and rating of each leak test and an identification number for each truck. However, based on comments received, the Department decided to drop this recordkeeping requirement. Instead, the load-out records will identify the truck performing the load-out, identify the leak test classification, the date and time the load-out occurred, and the type and volume of liquids loaded. These records can then be used to calculate emissions due to the load-out operations for the emissions inventory.

F. Fugitive Emissions Components

Equipment leaks are typically low-level, unintentional losses of process gas from the sealed surfaces of above-ground process equipment. Equipment components that tend to leak include valves, flanges and other connectors, pump seals, compressor seals, pressure relief valves, open-ended lines, and sampling connections. These components represent mechanical joints, seals, and rotating surfaces, which in time tend to wear and develop leaks. However, a release from any equipment or component designed by the manufacturer to protect the equipment, controller, or personnel or to prevent groundwater

contamination, gas migration, or an emergency situation is not considered a leak. The following requirements have been included to minimize and/or eliminate the equipment leaks.

In accordance with the Department's requirements under the previous version of GP-5, the owner or operator of a natural gas compression facility and/or natural gas processing facility shall, at a minimum on a monthly basis, perform an LDAR program which includes AVO inspections. This requirement is to be extended to unconventional natural gas well sites, remote pigging stations, and natural gas transmission stations covered by the final General Permits.

In the previous version of the GP-5, the owner or operator of the facility was required to use an OGI camera or other leak detection device to conduct an LDAR program inspection within 180 days after the initial startup of a source and at a minimum of once a quarter thereafter. This requirement has been changed to within 60 days after the initial startup of a source to meet the 40 CFR Part 60 Subpart OOOOa requirement and align with the LDAR requirements for unconventional natural gas well sites, which are required to perform an LDAR program inspection within 60 days of the start of production.

Based upon the cost-effectiveness analysis of Appendix E – LDAR Cost Analysis, the Department determined that quarterly inspections are BAT for unconventional natural gas well sites and remote pigging stations. An owner or operator of an unconventional natural gas well site or remote pigging station may track the number of leaking components in the LDAR program and reduce the inspection interval from once per quarter to semi-annually if the percentage of leaking components is less than 2.0% for two consecutive inspections. If the percentage of leaking components is higher than 2.0% in any inspection, the quarterly LDAR inspection interval must be resumed or maintained.

Consistent with 40 CFR Part 60, Subparts KKK, OOOO, and OOOOa, the LDAR requirements for natural gas processing plants are to use Method 21. As per 40 CFR §65.7(e), when a Method 21 inspection is required in any subpart of Parts 60, 61, 63, and 65, OGI camera inspections are an accepted alternative work practice for monitoring equipment for leaks. Therefore, the Department requires that all LDAR inspections covered by GP-5 and GP-5A use the same criteria, including those at natural gas processing plants under 40 CFR §§60.484 and 60.484a.

A leak is defined as any positive indication, whether audible, visual, or odorous, determined during an AVO inspection, any visible emission detected by an OGI camera calibrated according to 40 CFR §60.18 and a detection sensitivity level of 60 g/h, or a concentration of 500 ppm or greater calibrated as methane detected by an instrument that meets the requirements of 40 CFR Part 60, Appendix A-7, Method 21, regardless of source. However, a release from any equipment or component designed by the manufacturer to protect the equipment, controller, or personnel or to prevent groundwater contamination, gas migration, or an emergency situation is not considered a leak.

If any leak is detected, the owner or operator of the facility shall make a first attempt of repair within five days of the detection of the leak. The leak must be repaired no later than 15 days after the leak is detected, unless the repair requires the ordering of parts, in which case the repair must be completed no later than 10 days after receipt of the parts, or if the repair is technically infeasible without a vent blowdown, facility shutdown, or well shut-in or would be unsafe to repair during operation of the unit, in which case the repair must be completed at the earliest of the next scheduled facility shutdown, after a planned vent blowdown, or within two years.

Several commentators were concerned over the requirement that a repair that is technically infeasible without a blowdown, shutdown, or shut-in must be completed during an unscheduled blowdown. This was consistent with EPA's requirement in 40 CFR Part 60 Subpart OOOOa. The commentators were

concerned that if the facility undergoes an emergency shutdown and parts are not on hand to complete the repair, the facility would have to remain shut down until the repair is completed. The commentators petitioned the EPA to change the requirement, which was granted; subsequently, the Department amended the final General Permits to reflect the change.

A leak is considered repaired if one of the following can be demonstrated:

- No detectable emissions consistent with 40 CFR Part 60, Appendix A-7, Method 21 Section 8.3.2;
- A concentration of less than 500 ppm calibrated as methane is detected when the gas leak detector probe inlet is placed at the surface of the component;
- No visible leak image when using an OGI camera calibrated in accordance with 40 CFR §60.18 with a detection sensitivity of 60 g/h; or
- No bubbling at leak interface using a soap solution bubble test specified in Section 8.3.3 of 40 CFR Part 60, Appendix A-7, Method 21.

LDAR is considered to have a fugitive emission control rate based on the frequency of the inspection. According to EPA and Colorado²² the emissions reductions from annual LDAR is 40% and from quarterly LDAR is 60%. In 40 CFR Part 60, Subpart OOOOa, LDAR is required semi-annually for well pads and quarterly for compression stations and processing plants. Using 50% emissions reduction for semi-annual LDAR and 60% emission reduction for quarterly LDAR programs, the Department evaluated cost-effectiveness. As shown in Appendix E – LDAR Cost Analysis, the cost-effectiveness is \$516 for well pad and \$144 for transmission facilities. Therefore, the final GP-5A requires quarterly LDAR for sources at unconventional natural gas well sites or remote pigging stations and the final GP-5 requires quarterly LDAR for sources at natural gas compression, processing, and transmission facilities to minimize fugitive emissions.

The Department determined that the VOC and methane emissions remaining after the implementation of BAT requirements, including LDAR, are of minor significance with regard to causing air pollution, and will not, on their own merits, be preventing or interfering with the attainment or maintenance of an ambient air quality standard.

G. Controllers

Controllers are automated instruments used for maintaining liquid levels, pressure, and temperature at unconventional natural gas well sites, remote pigging stations, natural gas compression stations, natural gas processing plants, and natural gas transmission stations. These controllers often are powered by high-pressure natural gas and may release methane, VOC, and HAP with every valve movement (i.e., intermittent bleed), or continuously (i.e., continuous bleed) as part of their normal operations.

Existing controllers shall comply with the applicable requirements specified in 40 CFR Part 60, Subpart OOOO. For pneumatic controllers located at unconventional natural gas well sites, remote pigging stations, natural gas compression stations, and natural gas transmission stations this means they must be low-bleed controllers with an emission rate less than or equal to 6.0 standard cubic feet per hour unless a higher bleed rate is required for operational reasons such as speed, safety, or positive actuation.

²² ICF International, Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries, March 2014.

The Department originally proposed that new controllers constructed on or after the effective date of the final General Permits should either be an electric controller if the facility has access to electricity on site or meet the requirements of 40 CFR Part 60 Subpart OOOOa if electricity is not available on site. Several commentators pointed out that electric controllers can compromise facility reliability because electric power can fail; using electric controllers could compromise safety. The Department removed the requirement to install electric controllers at facilities based on these safety and reliability concerns. However, pneumatic controllers must comply with Subpart OOOOa when located at unconventional natural gas well sites, remote pigging stations, natural gas compression stations, and natural gas transmission stations. This means they must be low-bleed controllers with an emission rate less than or equal to 6.0 standard cubic feet per hour unless a higher bleed rate is required for operational reasons as above.

The owner or operator of new and existing controllers located at a natural gas processing plant shall employ no-bleed pneumatic controllers. These can be electrically actuated controllers or pneumatic controllers driven by instrument air. Natural gas actuated controllers that route the emissions into the downstream pipeline can also be used.

H. Pumps

Pumps are primarily used at unconventional natural gas well sites, remote pigging stations, natural gas compression stations, processing plants, and transmission stations for glycol circulation or for injecting chemicals used in normal operations. Pneumatic pumps use pressurized air or natural gas to operate the pump; at natural gas facilities, it is common to use natural gas from the production stream to operate the pumps. The pressurized natural gas, after being used to operate the pump, is often vented to the atmosphere through the exhaust port. There are many options available to reduce or eliminate emissions to the atmosphere.

Pneumatic pumps had no standards in 40 CFR Part 60, Subpart OOOO other than the LDAR requirements for pumps at natural gas processing facilities. In 40 CFR Part 60, Subpart OOOOa, natural gas-driven diaphragm pumps have control requirements for GHG and VOC depending upon the type of facility at which they are located and the number of days they are operated. Subpart OOOOa does not have a requirement for pumps located at natural gas compression stations.

In the proposed GPs, the Department required that electric pumps be used at any facility other than a natural gas processing plant that has access to electricity on site. For facilities that do not have access to electricity on site, the Department proposed that the requirements of 40 CFR Part 60, Subpart OOOOa, which were detailed in the General Permit, are BAT for pumps located at unconventional natural gas well sites and natural gas processing plants. The Department also proposed that the requirements for pumps at well sites are also BAT for pumps located at remote pigging stations, natural gas compression stations, and transmission stations. The Department also proposed to collect information on other types of pneumatic pumps by having notification, recordkeeping, and reporting requirements for all pneumatic pumps.

However, based on comments received, and the current challenges to Subpart OOOOa, the Department reevaluated the requirements for pumps. Based on the cost analysis in Appendix D – Cost Analysis for Combustion Control Devices, the Department determined that pumps with emissions greater than or equal to the control thresholds for methane of 200 tpy, VOC of 2.7 tpy, a single HAP of 0.5 tpy, or combined HAP of 1.0 tpy must control methane, VOC, and HAP emissions by 95%. For pumps with methane, VOC, and HAP emissions below the control thresholds, they must meet the applicable

requirements of 40 CFR Part 60 Subpart OOOOa. These requirements were incorporated into the General Permits by reference.

I. Enclosed Flares and Other Control Devices

Most of the BAT requirements for emissions sources are dependent on a control to reduce those emissions to the atmosphere. The conditions for operating, maintaining, and performance testing those control devices are included in this section of the General Permits. The proposed General Permits required 98% control efficiency which was based on the economic feasibility of combustion control devices, as shown in Appendix D – Cost Analysis for Combustion Control Devices. In addition, the Department demonstrated that at a combustion zone temperature of 1,600 °F a methane destruction of 98% is achievable.

However, in 40 CFR Part 60 Subparts OOOO and OOOOa, the operators have the option to purchase manufacturer-tested models, which require 95% VOC control efficiency. Therefore, the Department revised the methane, VOC, and HAP destruction efficiency required from 98% to 95% to enable the owners or operators to comply with the federal requirements and terms and conditions of the general permits using manufacturer-tested models. Even so, the manufacturer-tested models generally achieve higher than 95% destruction. The manufacturer-tested models also minimize the amount of performance tests required to be performed by the owner or operator relying instead on parametric monitoring to ensure compliance.

J. Pigging Operations

Pigging operations are undertaken to remove accumulated water and condensate liquids in natural gas gathering pipelines or to conduct pipeline integrity checks. These operations are done as necessary to maintain the optimal pressure in the pipeline that keeps the natural gas flowing and to push valuable condensate to tanks where it can be transported to a processing plant and ensure pipeline safety. The “pig” is a spherical or bullet-shaped device that travels through the pipeline to push the liquids to their eventual destination.

A pig must be loaded into the pipeline at a launching station and recovered at a receiving station. When the pig is launched and recovered, some of the natural gas in the chamber is vented to the atmosphere. This venting can be reduced by routing the gas to a vapor recovery unit, flare, or other control device. It can also be minimized in high-pressure pipelines by equalizing the high-pressure chamber with a low-pressure line before venting. Some of these technologies and techniques are employed in practice by MarkWest for their pigging operations. The EPA’s Partner Reported Opportunities (PRO) for Reducing Methane Emissions, also called NGStar, PRO Fact Sheet No. 505, gives information on other ways to minimize emissions from pigging operations.

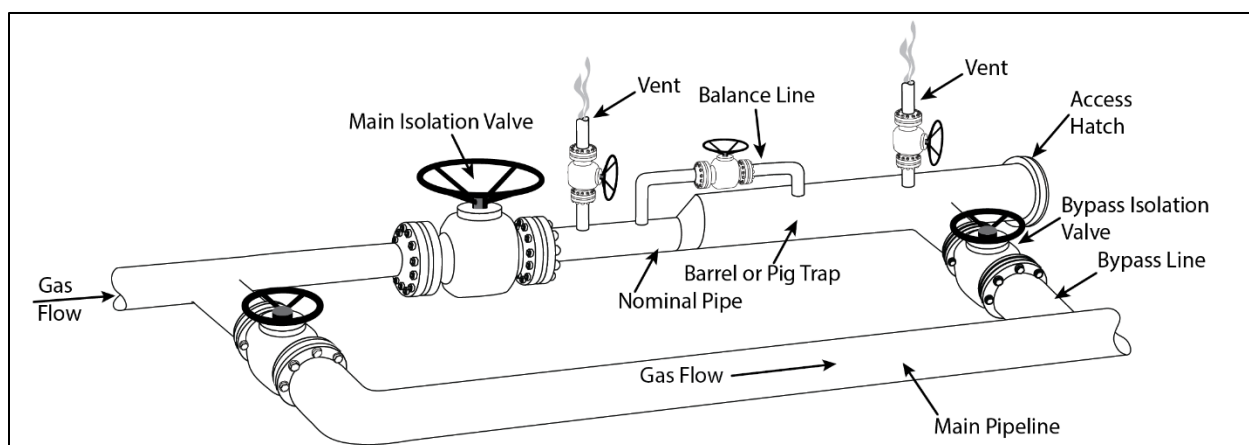


Figure 1: Drawing of a barrel type design of a pig launcher and receiver equipped with uncontrolled depressurization vents.²³

Even though EPA is familiar with pigging operations through the NGStar program, they did not address emissions from pigging operations in 40 CFR Part 60 Subpart OOOOa. However, the Department has evaluated and set requirements for pigging operations. As part of the Annual Emissions Inventory reporting requirements, the Department requires that the owner or operator of each pigging-affected facility calculate the total annual emissions of VOC and methane using the [Pigging Emissions Spreadsheet](#).

The owner or operator of a pigging operation shall minimize all emissions to the atmosphere to the highest extent possible. Originally, the Department required all pig receiver chambers to be equipped with a liquids drain and that all high-pressure pig launcher and receiver chambers be vented to a low-pressure pipeline or vessel if available in addition to any other best management practices (BMP) the operator decides to employ. The Department received comments recommending that DEP remove the proposed specific requirements and allow owners and operators to select all of the BMP they will implement for a specific operation. However, an owner or operator of a pigging operation whose emissions, after the application of BMP, still exceed the control thresholds for methane of 200 tpy, the total VOC of 2.7 tpy, the single HAP of 0.5 tpy, or the combined HAP of 1.0 tpy shall control methane, VOC, and HAP emissions by at least 95%.

XX. Sources Specific to GP-5A

A. Site Preparation, Well Drilling and Hydraulic Fracturing Operations

The first step in establishing a natural gas well is site preparation, which entails clearing, grading, and constructing access roads at the well site. This involves construction equipment which uses non-road engines that must meet the applicable non-road engine standards. The next step is the drilling phase; this typically entails drilling the wellbore in stages using either a diesel engine rig or a natural gas engine rig. Because the drill rig is on-site for a short period of time, the only standards that apply are that any drill rig engine must meet the applicable non-road engine standards. The owner or operator must provide at least 24 hours advance notification to the Department's Office of Oil and Gas Management before drilling. After the wellbore is completed and encased, the wellhead or "Christmas Tree" is installed.

²³ *Quantifying the Potential Impact of Natural Gas Condensate Holdup on Uncontrolled Volatile Organic Compound Emissions from Pig Receivers During Depressurization in Wet Gas Gathering Operations*, EPA Discussion Draft, May 2016.
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After the installation of the wellhead, the well is ready for hydraulic fracturing. Large volumes of water mixed with chemicals and proppants are pumped into the formation to create and hold open fractures in the shale; this fracturing technique greatly enhances natural gas production. Again, the owner or operator must provide at least 24 hours advance notification to the Department's Office of Oil and Gas Management before fracture. The trucks responsible for mixing the fracturing fluid and pumping underground also use non-road engines and must meet the applicable non-road engine standards. These are summarized in the tables in Appendix G – Non-road Engine Standards.

Several commentators informed the Department that these temporary operations may be carried out a year or more in advance of the installation of any permanent air emissions source. The well drilling and hydraulic fracturing typically lasts from a few weeks to a few months. In addition, except for California, States are preempted from establishing emission standards for non-road engines under Section 209 of the CAA. However, these engines must comply with applicable EPA non-road engine standards at 40 CFR Parts 89, 1039, and 1048. Therefore, the Department has removed requirements related to site preparation, well drilling, hydraulic fracturing, and well completion from the final GP-5A and maintained the exemption for these temporary operations in Category 38(c) of the Air Quality Permit Exemptions document.

B. Well Completion Operations

After a natural gas well is hydraulically fractured, the well must be prepared to produce natural gas by removing the fluid used in the fracturing process from the well. During this process, equipment such as a separator is used to separate and remove the sand and water from the natural gas stream. The separated gas, instead of being vented, is either captured and routed to a sales pipeline, or is flared. By not directly venting the gas to the atmosphere, both methane and VOC emissions are greatly reduced. This method of completing a natural gas well is called reduced emission completion (REC) or green completion.

The owner or operator shall use REC methods in accordance with requirements specified in 40 CFR Part 60, Subpart OOOOa. Also, any existing well that is refractured after the applicability date of Subpart OOOOa subjects existing sources at a facility to the fugitive emissions components requirements in the final GP-5A. As stated above, these operations are also temporary in nature. While well completion is likely to occur much closer to the installation of permanent air emission sources, there may still be significant time between when the completion occurs and when air contamination sources are due to be installed. This could lead to inaccurate applications being submitted and many reauthorizations of the General Permit, increasing the administrative burden on the industry and the Department. Because the requirements for well completion operations are no different than those required by state and federal regulations, the Department removed these temporary operations from the final GP-5A and maintained the exemption for them in the Category 38(c). Even though these operations will not require an air permit, the operators will still be required to meet the applicable state and federal regulations, including notifying both the Air Program Manager of the appropriate Regional Office and the Department's Office of Oil and Gas Management 24 hours prior to the start of flowback.

C. Wellbore Liquids Unloading

Over time, liquids may accumulate in a producing natural gas well and may reduce the well pressure to the point where production is reduced, especially in wells located in the wet gas areas. When this happens, the accumulated fluids need to be removed in order to restore production through a process called liquids unloading. There are many techniques that can be used to accomplish this, including venting, soaping, swabbing, and using a plunger lift system. As indicated in EPA's white paper on Oil

and Natural Gas Sector Liquids Unloading Processes²⁴, the use of technologies like a plunger lift system can reduce the frequency of liquids unloading operations.

However, the basic criteria for the installation of a plunger lift, as found in EPA's NGStar program²⁵, are as follows:

- Wells must produce at least 400 scf of gas per barrel of fluid per 1,000 feet of depth.
- Wells with shut-in wellhead pressure that is 1.5 times the sales line pressure.
- Wells with scale or paraffin buildup.

These conditions may not be found at all wells covered by the GP-5A, so plunger lift systems remain an option but not a requirement for wellbore liquids unloading. Furthermore, in comments to EPA in the rulemaking for 40 CFR Part 60 Subpart OOOOa, the American Petroleum Institution (API) states that it is a misconception that plunger lift systems are the single emission control action for wells where venting for liquids unloading occurs.

“This misconception is exacerbated by a lack of understanding, even among those purporting plunger lift systems as *the* solution to liquids unloading, of liquids loading or plunger lift systems and their appropriate uses, limitations, and efficacy. Plungers work by providing a mechanical barrier between a small volume of water and the gas that is used to transport it up the well-bore. The mechanical barrier isolates the gas from the liquids, prevents gas from moving up through the liquids hence making better use of the gas energy, and helps prevent liquids from falling back into the well-bore. If the gas could flow faster, then that mechanical barrier would not be necessary or helpful.

Although plungers are among the most common tools used in middle stage deliquification, there is a misconception that plungers eliminate the need to vent to atmosphere. In many cases, wells are vented to atmosphere to generate the differential pressure necessary to lift the plunger and liquid column up the well-bore. While this can be controlled and minimized, it cannot be eliminated.

As the API/ANGA report and the GHGRP data show, venting of wells to aid liquids unloading occurs in both plunger equipped wells and non-plunger equipped wells with plunger equipped wells having higher reported emissions overall.”

There was another EPA white paper²⁶ that detailed other alternatives to repeated well venting to remove accumulated liquids including surfactants, velocity tubing, manual plunger lifts, automated plunger lifts, and downhole pumps. However, EPA did not address emissions from wellbore liquids unloading operations in 40 CFR Part 60 Subpart OOOOa. However, the Department evaluated emissions from

²⁴ U.S. EPA Office of Air Quality Planning and Standards, *Report for Oil and Natural Gas Sector Liquids Unloading Processes Review Panel*, April 2014, located at <http://www.ourenergypolicy.org/wp-content/uploads/2014/04/epa-liquids-unloading.pdf>, last accessed on May 24, 2018.

²⁵ U.S. EPA's Natural Gas STAR Program, *Lessons Learned from Natural Gas STAR Partners: Installing Plunger Lift Systems in Gas Wells*, October 2006, located at https://www.epa.gov/sites/production/files/2016-06/documents/ll_plungerlift.pdf, last accessed on May 24, 2018.

²⁶ U.S. EPA's Natural Gas STAR Program, *Lessons Learned from Natural Gas STAR Partners: Options for Removing Accumulated Fluid and Improving Flow in Gas Wells*, 2011, located at https://www.epa.gov/sites/production/files/2016-06/documents/ll_options.pdf, last accessed on May 24, 2018.

wellbore liquid operations to determine BAT. In general, there has been great support in the comments for including wellbore liquids unloading operations in the GP-5A.

The Department learned through conversations with some industry representatives, that one of the largest factors in emissions from wellbore liquids unloading events is the length of time that flow is directed to atmospheric pressure. Therefore, one of the most effective methods to reduce the time venting to atmospheric pressure would be to ensure that an operator remains on site for the duration of a manual unloading operation. However, one commentator stressed that the requirement to have an operator onsite for the entire duration of a wellbore liquids unloading operation is burdensome, especially to small businesses. An unloading operation can take a significant amount of time, which is typically spent by an operator travelling to another site to initiate another unloading operation. The operator then travels back to each site, ending each unloading operation in turn. The time spent by an operator onsite would necessitate hiring significant additional staff that small businesses cannot easily afford.

Therefore, the Department has removed the requirement that the owner or operator shall ensure that an operator remains on site for the duration of a manual unloading operation. The requirement that the owner or operator use BMP including, but not limited to, a plunger lift system, soaping, swabbing, or venting to atmospheric pressure to minimize methane and VOC emissions during wellbore liquids unloading operations to mitigate emissions. In all cases, where technically feasible, the owner or operator shall direct the gas to a separator, storage vessel, or control device, unless it is necessary to vent to the atmosphere for safety.

XXI. Sources Specific to GP-5

A. Natural Gas-Fired Combustion Units

There are many different combustion units used at natural gas production and processing facilities. Some are small integrated units, typically rated at less than 2.5 MMBtu/h, such as those found on gas production units (GPU), heated flash separators, or glycol dehydration units. Others are large units, some larger than 10 MMBtu/h, such as the fractionation column heaters found at natural gas processing plants.

Often when natural gas first exits the wellbore, it contains free water, condensate, and water vapor that must be removed from the natural gas stream. GPUs perform this task, and many have small boilers that facilitate the removal of natural gas from the liquids stream through flashing, which volatilizes the gas from the liquids. In dry-gas regions, the liquid is primarily water, and is referred to as produced water. In rich-gas regions, the high percentage of condensate in the natural gas stream often requires further processing to ensure that the water and condensate are separated. Heated flash separator units are used for this purpose and are also equipped with small boilers to facilitate the condensate removal from the water by flashing. The flow of the natural gas and liquids through the GPUs and heated flash separator units are often controlled by integrated controllers and pumps.

Combustion units with a rated capacity of less than 10 MMBtu/h of heat input fired on natural gas supplied by a public utility are exempt from plan approval and operating permit requirements by the Air Quality Permit Exemptions document. Under Category 39 of the final Air Quality Permit Exemptions document, combustion units rated at less than 10 MMBtu/h firing natural gas supplied by an independent producer shall be exempt from plan approval, and the General Permits may function as the required operating permit. Even though the combustion units are exempt from plan approval and/or operating permits, the owner or operator will be required to list these sources in the *Application for*

Authorization to Use GP-5 or GP-5A for reference purposes to ensure compliance with the facility emissions limits. Any associated fugitive emissions components, controllers, and pumps will be subject to their respective requirements of the General Permit.

Table 12 identifies the applicable BAT emission limitations for combustion units rated greater than or equal to 10 MMBtu/h and less than or equal to 50 MMBtu/h:

Table 12 - BAT Emission Limits for Natural Gas-Fired Combustion Units

Constructed After:	NO_x (ppmvd @ 3% O₂)	CO (ppmvd @ 3% O₂)	PM (lb/MMBtu)	Opacity (No more than 3 minutes in an hour)	Opacit y (At any time)
December 2, 1995	30	300	0.4	20%	60%
August 8, 2018	30	130	0.4	10%	30%

1. NO_x Limit

The Department has found that there are few vendors that offer natural gas-fired combustion units with a NO_x emission rate of lower than 30 ppmvd corrected at 3% oxygen. These units are typically used in production facilities for producing steam. However, GP-5 includes combustion units including, but not limited to, heated flash separator units, evaporator units, fractionation column heaters, and glycol dehydrator reboilers. Typically, these combustion units are rated at less than 10 MMBtu/hr, which are exempted from permitting. Due to the availability of limited emissions data for units operating at natural gas production, compression and transmission facilities, the Department has established a NO_x emission limit for natural gas-fired combustion units at 30 ppmvd corrected @ 3% oxygen. The Department will continue to evaluate NO_x emissions data from these units.

2. CO Limit

The CO emission limit of 130 ppmvd corrected to 3% oxygen is consistent with the CO limit established in 40 CFR Part 63 Subpart DDDDD. Specifically, Table 1, Item 16 in Subpart DDDDD establishes for new or reconstructed boilers and process heaters the above-noted CO limit for “units designed to burn light liquid fuel.” While this limit is specific to light liquid fuels, like No. 2 fuel oil, the Department proposed this limit for both No. 2 fuel oil and natural gas.

B. Natural Gas-Fired Simple Cycle Turbines

A simple cycle turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. A turbine is composed of three major components: the compressor, the combustor, and the power turbine. In the compressor section, ambient air is drawn in and compressed up to 30 times the ambient pressure and directed to the combustor section where fuel is injected, ignited, and burned. The resultant gases are diluted with additional air from the compressor section and are expanded through the power turbine section, which consists of a series of rotors and stators to extract mechanical work via a shaft. A portion of the generated shaft power is used to drive the internal compressor; the rest is directed to external load. At natural gas compression stations, natural gas processing facilities, and natural gas transmission stations, turbines are used mainly as prime movers to drive centrifugal compressors or generators.

1. Emissions from Natural Gas-Fired Turbines

Natural gas-fired turbines produce many of the same pollutants as SI-RICE which are emitted from the exhaust, depending on the composition of the fuel used. In addition, PM emissions are an issue for turbines due to the high exhaust flows. Since formaldehyde emissions from natural gas-fired turbines are on the order of 7.10×10^{-4} lb/MMBtu uncontrolled as per EPA's AP-42 Emissions Factors, a 30,000 hp simple cycle turbine may emit approximately 0.6 tpy. However, this size turbine is required to install an oxidation catalyst, which would also reduce formaldehyde by 85-90%. Therefore, the Department has not established a formaldehyde limit for simple cycle turbines. Natural gas is the primary fuel used by the natural gas industry and is the only fuel authorized by GP-5.

2. Emission Control Technology

Several technologies may be used to control emissions from turbines. They primarily fall into two categories: combustion control and post-combustion control.

a. Combustion Control

Control of combustion temperature has been the principal focus of combustion process control in turbines. Combustion control requires tradeoffs – higher temperatures favor complete consumption of the fuel and lower residual hydrocarbons and CO, but result in NO_x formation. Lean combustion dilutes the fuel mixture and reduces combustion temperatures and NO_x formation.

Because the NO_x produced by combustion turbines is primarily thermal NO_x, reducing the combustion temperature will result in less NO_x production. Thus, the most common strategy for NO_x control is to control the combustion temperature. This is often done by using wet methods, such as steam or water injection, or dry methods, such as lean combustion or two-stage combustion.

i. Steam or Water Injection

Steam or water injection has been demonstrated to effectively suppress NO_x emissions from turbines. The effect of steam or water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. Steam or water is typically injected at a water-to-fuel weight ratio of less than one. Depending on the initial NO_x levels, such rates of injection may reduce NO_x by 60% or more. Both CO and VOC emissions are increased by steam or water injection, and the level of increase will depend on the water-to-fuel weight ratio.

ii. Dry Controls

Since thermal NO_x is a function of both temperature and time, the basis of dry controls is to either lower the combustor temperature using lean mixtures of air and fuel, fuel staging, or decreasing the residence time of the combustor. A combination of these methods may also be used to reduce NO_x emissions.

Lean combustion involves increasing the A/F ratio of the mixture so that the peak and average temperatures within the combustor will be less than that of the stoichiometric mixture, thus suppressing thermal NO_x formation. Introducing excess air not only creates a leaner mixture, but also reduces residence time at peak temperatures.

Two-stage combustion can be broken down into lean/lean and rich/lean staging, which both serve to reduce NO_x. In lean/lean staging, the combustor is a fuel-staged premixed combustor that operates at an extremely lean A/F ratio. A small stoichiometric pilot flame ignites the premixed gas to provide flame

stability. Because the NO_x emissions from the high temperature pilot flame are insignificant and the combustor is designed to operate at lower flame temperatures and to avoid localized “hot spots,” low NO_x emission levels are achieved. In rich/lean staging, the combustor is an air-staged premixed combustor where the primary zone is operated fuel rich and the secondary zone is fuel lean. The fuel-rich zone operates at an A/F ratio less than one, which produces higher concentrations of CO and decreases the amount of NO_x due to a lack of available oxygen and lower flame temperatures. The exhaust from the primary zone is then quenched and mixed with large amounts of air, creating a lean mixture which is pre-ignited and introduced to the secondary zone where combustion is completed. The lower temperature and lean mixture results in low NO_x emission levels. Staged combustion is identified through a variety of names, including Dry-Low NO_x (DLN), Dry-Low Emissions (DLE), or SoLoNO_x.

b. Post-Combustion Emission Reduction Technology for Turbines

i. Oxidation Catalyst (for CO and NMNEHC reduction)

Oxidation catalysts using platinum and palladium are effective for lowering CO, NMNEHC, and formaldehyde levels in exhaust emissions from turbines. For this analysis, the Department has determined that an oxidation catalyst is economically feasible for turbines if the cost per ton of CO and NMNEHC removal is approximately \$5,000; see Appendix C – Oxidation Catalyst and NSCR Cost Analysis for Engines and Turbines.

ii. Selective Catalytic Reduction (for NO_x reduction)

SCR is technically feasible on turbine exhaust streams, and the systems operate much like they do on engine exhaust streams. Urea or ammonia is typically used in SCR systems that control turbine NO_x emissions, which also results in ammonia emissions. For this analysis, the Department has determined that SCR is economically feasible for turbines if the cost per ton of NO_x removal is approximately \$10,000; see Appendix B – SCR Cost Analysis for Engines and Turbines.

3. Turbine Size Grouping

The Department chose to slightly alter the turbine size groups for natural gas compression stations, natural gas processing plants, and natural gas transmission stations. In the previous GP-5, the turbines were placed into the following categories:

- Greater than or equal to 1,000 bhp but less than 5,000 bhp;
- Greater than or equal to 5,000 bhp but less than 15,000 bhp; and
- Greater than or equal to 15,000 bhp.

In the final GP-5, the turbines were placed into the following categories:

- Greater than or equal to 1,000 bhp but less than 5,000 bhp;
- Greater than or equal to 5,000 bhp but less than 15,900 bhp; and
- Greater than or equal to 15,900 bhp.

4. Turbine Emission Limits

New sources are required to control the emission of air pollutants to the maximum extent, consistent with BAT as determined by the Department. The Department evaluated uncontrolled emissions, control

efficiency of various controls and associated costs, and stack test results for turbines to establish BAT. In the following sections, all references to the pollutant concentrations are given as ppm @ 15% O₂.

a. Turbines Rated Greater Than or Equal To 1,000 bhp but Less Than 5,000 bhp

Vendor data for turbines greater than or equal to 1,000 bhp but less than 5,000 bhp gave uncontrolled emission rates of 25 ppm NO_x, 25 ppm CO, and 25 ppm THC as methane. This was the basis of the BAT from the previous GP-5, and the THC emission rate was converted to NMNEHC as propane, establishing an emission rate of 9 ppm NMNEHC as propane.

SCR cost estimations were based on vendor quotes, cited as from Vendor A and Vendor B. It was assumed that the control efficiency for SCR is 90% for NO_x. All oxidation catalyst cost estimations were based on vendor data, with the costs quoted in 2007 dollars. The costs in the analysis were then multiplied by the CPI of 1.16 for inflating 2007 dollars to 2016 dollars. It was assumed that the control efficiencies for oxidation catalysts are 93% for CO and 50% for NMNEHC. See Appendix B – SCR Cost Analysis for Engines and Turbines and Appendix C – Oxidation Catalyst and NSCR Cost Analysis for Engines and Turbines for the analyses.

Using the uncontrolled and BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for an oxidation catalyst for turbines greater than or equal to 1,000 bhp but less than 5,000 bhp is estimated between \$8,142 and \$13,810 per ton of pollutants reduced. The Department determines that an oxidation catalyst is not economically feasible based on the cost-effectiveness benchmark of approximately \$5,000 per ton of pollutant reduced. Therefore, BAT for turbines greater than or equal to 1,000 bhp but less than 5,000 bhp are emission limits of 25 ppm for CO and 9 ppm for NMNEHC as in the previously issued GP-5.

Using the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for turbines greater than or equal to 1,000 bhp but less than 5,000 bhp is estimated between \$11,622 and \$18,853 per ton of NO_x reduced. The Department determines SCR is not BAT for turbines greater than or equal to 1,000 bhp but less than 5,000 bhp because it is not economically feasible based on a cost-effectiveness benchmark of \$10,000 per ton of NO_x reduced and the emission limit remains 25 ppm for NO_x as in the previously issued GP-5.

b. Turbines Rated Greater Than or Equal To 5,000 bhp but Less Than 15,900 bhp

Vendor data for turbines greater than or equal to 5,000 bhp but less than 15,900 bhp gave uncontrolled emission rates of 25 ppm NO_x, 25 ppm CO, and 25 ppm THC as methane. This was the basis of the BAT from the previous GP-5 for CO and NMNEHC, and the THC emission rate was converted to NMNEHC as propane, establishing an emission rate of 9 ppm NMNEHC as propane. BAT for NO_x was established as 15 ppm based on stack test results.

Using the uncontrolled and BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for an oxidation catalyst for turbines greater than or equal to 5,000 bhp but less than 15,900 bhp is estimated between \$4,836 and \$6,612 per ton of pollutants reduced. However, according to stack test data, emission rates of 10 ppm CO and 5 ppm NMNEHC are achievable without control. Using the stack test emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for an oxidation catalyst for turbines greater than or equal to 5,000 bhp but less than 15,900 bhp is estimated between \$11,082 and \$15,153 per ton of pollutants reduced. Therefore, it is the Department's determination that turbines greater than 5,000 bhp but less than 15,900 bhp have BAT criteria with emission limits of 10.00 ppm for CO and 5.00 ppm for

NMNEHC whether attained through use of an oxidation catalyst or good combustion engineering practices.

Using the uncontrolled emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for turbines greater than or equal to 5,000 bhp but less than 15,900 bhp is estimated between \$7,714 and \$9,810 per ton of NO_x reduced. Using the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for turbines greater than or equal to 5,000 bhp but less than 15,900 bhp is estimated between \$12,858 and \$16,351 per ton of NO_x reduced. Therefore, it is the Department's determination that turbines greater than 5,000 bhp but less than 15,900 bhp have BAT criteria with emission limits of 15.00 ppm for NO_x whether attained through use of an SCR or good combustion engineering practices.

c. Turbines Rated Greater Than or Equal To 15,900 bhp

Vendor data for turbines greater than or equal to 15,900 bhp gave uncontrolled emission rates of 25 ppm NO_x, 25 ppm CO, and 25 ppm THC as methane. This was the basis of establishing oxidation catalysts as BAT from the previous GP-5 for CO and NMNEHC, and the THC emission rate was converted to NMNEHC as propane, establishing an emission rate of 9 ppm NMNEHC as propane. An alternative BAT of 10 ppm CO and 5 ppm NMNEHC based on stack test results was offered in the previous GP-5. BAT for NO_x was established as 15 ppm also based on stack test results.

Using the uncontrolled emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for an oxidation catalyst for turbines greater than or equal to 15,900 bhp is estimated between \$3,576 and \$4,321 per ton of pollutants reduced. Using the alternative BAT emission rates, the assumed control efficiencies, and assuming a full year of operation, the control cost for an oxidation catalyst for turbines greater than or equal to 15,900 bhp is estimated between \$8,243 and \$9,903 per ton of pollutants reduced. Therefore, it is the Department's determination that turbines greater than 15,900 bhp have dual BAT criteria with emission limits of 10.00 ppm for CO uncontrolled or 1.75 ppm for CO through use of an oxidation catalyst. It is the Department's determination that turbines greater than 15,900 bhp have BAT criteria with emission limits of 5.00 ppm for NMNEHC whether attained through use of an oxidation catalyst or good combustion engineering practices.

Using the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for turbines greater than or equal to 15,900 bhp is estimated to be less than \$11,466 per ton of NO_x reduced. The Department determines SCR is BAT for turbines greater than or equal to 15,900 bhp. However, recently issued permits and plan approval applications show turbines greater than or equal to 15,900 bhp are capable of achieving 9.0 ppm for NO_x uncontrolled. Using the 9.0 ppm emission rate, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for turbines greater than or equal to 15,900 bhp is estimated to be between \$16,946 and \$19,106 per ton of NO_x reduced.

Most SCR vendors guarantee NO_x emissions reduction of 90% or more and therefore, with an uncontrolled baseline NO_x emission rate of 15 ppmvd corrected to 15% oxygen, which is established as achievable, the Department proposed a NO_x emission limit of 1.5 ppmvd @ 15% O₂. The Department has permitted several turbines equipped with SCR with emission limits of 2 to 2.5 ppmvd NO_x @ 15% O₂. The stack test results for these turbines show NO_x emissions range from 1.6 to 1.8 ppmvd. Therefore, the Department has determined that 2.0 ppmvd NO_x @ 15% O₂ is BAT in the final GP-5 for turbines rated greater than or equal to 15,900 hp.

Therefore, it is the Department's determination that turbines greater than or equal to 15,900 bhp have dual BAT criteria with emission limits of 9.00 ppmvd for NO_x uncontrolled and 2.0 ppmvd for NO_x through use of SCR.

Table 13 - BAT Emission Limits for Existing Turbines

Turbine Rating (bhp)	NO_x (ppmvd @ 15% O₂)	CO (ppmvd @ 15% O₂)	NMNEHC (as propane) (ppmvd @ 15% O₂)	Total PM (lbs/MMBtu)
1,000 ≤ TR < 5,000	25	25	9.0	0.03
5,000 ≤ TR < 15,000	15	25	9.0	0.03
≥ 15,000	15	10. <u>or</u> 93% reduction	5.0 <u>or</u> 50% reduction	0.03

Table 14 - Proposed BAT Emission Limits for New Turbines

Turbine Rating (bhp)	NO_x (ppmvd @ 15% O₂)	CO (ppmvd @ 15% O₂)	NMNEHC (as propane) (ppmvd @ 15% O₂)	Total PM (lbs/MMBtu)
1,000 ≤ TR < 5,000	25	25	9.0	0.03
5,000 ≤ TR < 15,900	15	10.	5.0	0.03
≥ 15,900	9.0 Uncontrolled or 2.0 with Control	10. Uncontrolled or 1.8 with Control	5.0	0.03

In addition, the turbines shall comply with all applicable requirements specified in 40 CFR Part 60, Subpart KKKK.

However, for all previous versions of the GP-5, the Department's BAT requirements are more stringent than those required under Subpart KKKK. Therefore, by complying with the Department's BAT requirements, the owner or operator of a turbine will be guaranteed compliant with the applicable requirements of 40 CFR Part 60 Subpart KKKK.

Visible emissions shall not meet or exceed 10% opacity for a period or periods aggregating more than three minutes in any one hour nor meet or exceed 30% opacity at any time.

Based on the comments received, the Department added a provision that the owner or operator shall also operate the turbine and air pollution control equipment consistent with good air pollution control practices during periods of low ambient air temperature (at or below 0 °F) during which times the emission standards do not apply. This is consistent with the requirements of 40 CFR Part 60 Subpart KKKK.

5. Turbine Core Replacement

A turbine core must be done in accordance with the terms and conditions of the GP-5; these terms and conditions are consistent with turbine core replacement requirements established for landfill gas-fired turbines in GP-22.

C. Centrifugal Natural Gas Compressors

Like reciprocating natural gas compressors, centrifugal natural gas compressors are used to increase the pressure of natural gas in a pipeline in order to take advantage of the property of fluids moving from high-pressure to low-pressure areas. In a centrifugal compressor, however, rotary motion from the prime mover is used to drive an impeller that imparts energy into the gas which serves to increase its pressure. There can be multiple stages of impellers that can generate a large change in pressure.

Like the reciprocating natural gas compressor, the centrifugal compressor has a shaft that must be sealed to reduce wear and maintain gas pressure. These seals can be either dry or wet; the wet seal uses an oil film in its operation. However, the oil used in a wet seal system collects natural gas, which must be removed in order to maintain the seal effectiveness.

It is not typical for centrifugal compressors to be installed at an unconventional natural gas well site. According to 40 CFR Part 60, Subparts OOOO and OOOOa, centrifugal compressors located at well sites are not affected facilities. The Department is therefore not proposing to authorize centrifugal compressors at unconventional well sites or remote pigging stations through the GP-5A; centrifugal compressors at natural gas compression stations, processing plants, and transmission stations are authorized in the GP-5.

1. Existing Centrifugal Natural Gas Compressors

The owner or operator of an existing wet seal centrifugal natural gas compressor shall continue to comply with the 95% control and other applicable requirements specified in 40 CFR Part 60, Subpart OOOO, which are incorporated by reference in the GP-5.

2. New Centrifugal Natural Gas Compressors

40 CFR Part 60, Subpart OOOOa requires centrifugal compressor to be equipped with dry seal or wet seal where methane and VOC emissions from the wet seal degassing system is reduced by 95% or more. Based on the Department's evaluation, no additional requirements are needed. Therefore, the Department determines that the recently promulgated requirements of 40 CFR Part 60, Subpart OOOOa are determined to be BAT.

D. Natural Gas Fractionation Process Units

Condensates, or NGLs, are an important product of natural gas production. In much of the production segment, the condensates are separated from the natural gas stream and stored in tanks before eventually being shipped to a processing plant via truck. However, condensates are still part of the natural gas stream and may fall out during transport in a pipeline. The fluid buildup can cause flow problems, which are typically cleaned through a pigging operation. In this case, the NGLs can be sent to a tank called a slug catcher which may be located at a compression station or processing plant. The liquids at a compression station are also commonly transported via a truck.

Natural gas fractionation is the process of separating the various hydrocarbons in NGLs by extracting them in sequence in heated columns. Any methane, which is the lightest of the hydrocarbons, remaining in the condensate is separated first, and put into the pipeline for transmission and storage. Then ethane, propane, and butane are removed in turn and sent to their respective storage tanks; butane may be further divided into isobutane and n-butane. The heavier NGLs are called natural gasoline and will typically be sent to another plant for further refinement.

Potential emissions from natural gas fractionation units are from the process heaters and the fugitive emissions associated with piping, valves, flanges, pumps, compressors, and pressure relief devices. Process heaters for fractionation columns eligible for authorization under the GP-5 range in size up to 50 MMBtu/h. Combustion units rated less than 2.5 MMBtu/h are exempt from plan approval by 25 Pa. Code §127.14(a). Under Category 39 of the Air Quality Permit Exemptions document, combustion units rated less than 10 MMBtu/h firing natural gas supplied by an independent producer shall be given the same consideration given to similarly sized sources that fire natural gas provided by a public utility. Even though the process heaters described are exempt, these sources will be listed in the permit for reference purposes. However, emissions from these exempt units must be included in the facility emissions totals for tracking compliance with the General Requirements (i.e., the 12-month rolling sum must remain below the major source emissions thresholds) and in the annual emissions inventory.

Natural gas processing, which includes fractionation, is subject to federal requirements under 40 CFR Part 60, Subpart KKK for units which were constructed, reconstructed, or modified after January 20, 1984, and on or before August 23, 2011. After August 23, 2011, and on or before September 18, 2015, fractionation process units are subject to the requirements of 40 CFR Part 60, Subpart OOOO. After September 18, 2015, fractionation process units are subject to the requirements of 40 CFR Part 60, Subpart OOOOa. In all cases, the primary standards are monitoring for equipment leaks using 40 CFR Part 60, Appendix A-7, Method 21.

Because potential emission sources associated with natural gas fractionation are addressed individually, i.e. in the sections related to combustion units and fugitive emissions components, a separate section for natural gas fractionation units was not incorporated into the final General Permit.

E. Sweetening Units

Natural gas from some wells contains sulfur and carbon dioxide, which must be removed to protect personnel, the environment, and equipment. Sulfur typically exists in natural gas in the form of hydrogen sulfide (H_2S), and natural gas where the H_2S content exceeds 4 ppm is referred to as sour gas. The process for removing H_2S from sour gas is called sweetening the gas.

The primary process for sweetening sour gas is similar to the process of glycol dehydration. An amine solution is used to remove the H_2S by passing the sour gas through a tower where it contacts the solution and is absorbed. There are two primary amine solutions used, monoethanolamine (MEA) and diethanolamine (DEA). Either of these compounds, in liquid form, will absorb sulfur compounds and CO_2 from the sour gas leaving the effluent gas virtually free of these contaminants. Both MEA and DEA can be regenerated and the resultant gases can be used to feed a Claus process, which involves using thermal and catalytic reactions to extract elemental sulfur from the hydrogen sulfide solution.²⁷

Potential emissions from sweetening units are from the process heaters; the fugitive emissions associated piping, valves, flanges, pumps, compressors, and pressure relief devices; and the tail gas of

²⁷ NaturalGas.org, last accessed on May 24, 2018.

the Claus process. Process heaters for sweetening units are eligible for authorization under the GP-5 up to 50 MMBtu/h in size. Combustion units rated less than 2.5 MMBtu/h are exempt from plan approval by 25 Pa. Code §127.14(a). Under Category 39 of the Air Quality Permit Exemptions document, combustion units rated less than 10 MMBtu/h firing natural gas supplied by an independent producer shall be given the same consideration given to similarly sized sources that fire natural gas provided by a public utility. Even though the described process heaters are exempt, these sources will be listed in the permit for reference purposes. However, emissions from these exempt units must be included in the facility emissions totals for tracking compliance with the General Requirements (i.e., the 12-month rolling sum must remain below the major source emissions thresholds) and in the annual emissions inventory.

Sweetening units are subject to federal requirements under 40 CFR Part 60, Subpart LLL for units which were constructed, reconstructed, or modified after January 20, 1984, and on or before August 23, 2011. After August 23, 2011, and on or before September 18, 2015, sweetening units are subject to the requirements of 40 CFR Part 60, Subpart OOOO. After September 18, 2015, sweetening units are subject to the requirements of 40 CFR Part 60, Subpart OOOOa. The standards are for a target control efficiency for SO₂ emissions based on sulfur production.

Because the Authorization to Use the GP-5 and GP-5A cannot be granted to facilities that produce or process sour gas as shown in the basic calculations in the section on Oxides of Sulfur in General Methodology of Determining Best Available Technology, the SO₂ emissions limits from the federal regulations were not included in the General Permits. Should a sweetening unit be needed to remove excess CO₂, the potential emissions sources from the sweetening unit are addressed individually, i.e., in the sections on combustion units and fugitive emissions components, and therefore a separate section on sweetening units was not incorporated into the General Permits.

XXII. Appendix A – Average Gas Composition Analysis

Table 15 - Methane de Minimis Calculations

	Average Gas Composition	Donald R. Bowser #1M-207	Roundwood Wyo	Martin Sanders 1M	Liberty	Kenneth L. Crosby #1M-69	Petraitis	Boyanowski Wyo	Jack Wyo	Lopatofsky Wyo	Fanclaire Wyo	Susan Sus	Delhagen Sus
Methane	88.78%	63.08%	93.85%	83.21%	93.51%	70.94%	91.37%	93.90%	94.52%	95.41%	94.32%	95.49%	95.72%
Ethane	5.93%	7.91%	4.94%	4.98%	4.48%	17.15%	6.69%	4.77%	4.44%	3.86%	4.58%	3.71%	3.60%
Propane	0.88%	1.53%	0.36%	0.55%	0.36%	5.64%	0.73%	0.34%	0.26%	0.18%	0.31%	0.17%	0.15%
Butane (iso- and n-)	0.27%	0.44%	0.05%	0.03%	0.05%	2.30%	0.13%	0.07%	0.04%	0.01%	0.05%	0.01%	0.01%
Pentane (iso- and n-)	0.05%	0.09%	0.00%	0.00%	0.00%	0.49%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Hexane and above	0.05%	0.00%	0.00%	0.00%	0.00%	0.62%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Carbon Dioxide	0.21%	0.16%	0.05%	0.30%	0.75%	0.17%	0.66%	0.06%	0.05%	0.06%	0.05%	0.07%	0.10%
Molecular Nitrogen	3.85%	26.78%	0.74%	10.93%	0.41%	3.32%	0.41%	0.83%	0.69%	0.48%	0.65%	0.54%	0.42%
Sum of Parts	100.01%	99.99%	99.99%	100.00%	99.56%	100.63%	100.03%	99.97%	100.00%	100.00%	99.96%	99.99%	100.00%
VOC (sum of propane and above)	1.25%	2.06%	0.41%	0.58%	0.41%	9.05%	0.90%	0.41%	0.30%	0.19%	0.36%	0.18%	0.16%
VOC de minimis (TPY)	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Methane de minimis (TPY)	191.6	82.7	618.0	387.4	615.8	21.2	274.1	618.4	850.7	1,355.8	707.4	1,432.4	1,615.3
Average of Columns (C through N) Methane de minimis (TPY)					714.9								

The general methodology for determining the methane control threshold is to calculate the amount of methane in a natural gas release relative to the amount of VOC that reaches the VOC control threshold using a standard mass-balance calculation. Using twelve different gas samples, the methane control thresholds ranged from a minimum of 21.2 tpy to a maximum of 1,615.3 tpy. The average of the twelve calculated control thresholds is 714.9 tpy, which is 17,872 tpy of CO_{2e}. This value is nearly 25% of the 75,000 tpy CO_{2e} major modification facility threshold for greenhouse gases.

Therefore, the Department calculated an average gas composition from the twelve samples and followed the same methodology for determining the methane control threshold with a result of 191.6 tpy. The Department conservatively used 200 tpy methane to account for the scientific uncertainty due to the limited number of gas samples used in the calculation, which is equivalent to 5,000 tpy CO_{2e}. This is approximately 7% of the facility greenhouse gas threshold and is much more reasonable to use as the methane control threshold.

However, several commentators stated that the Department’s calculated average gas composition was not representative of natural gas in Pennsylvania because of its small sample size and limited geographic scope. To improve the average gas composition calculation, the Department decided to expand the scope of the analysis. For every county with wells displayed on eMapPA, the Department attempted to obtain at least five reasonable representative gas analyses, two from compressor stations or processing plants, and three from unconventional natural gas well sites. The sample included 59 representative gas analyses across all of the regions with oil and gas activity including the Southwest, Northwest, North Central, and Northeast Regions of Pennsylvania. The Department then calculated a county average gas composition for each county, and a state average gas composition by averaging the county average gas compositions. Therefore, the Department reduced the scope of scientific uncertainty based on geographic location.

Table 16 - Average Gas Composition Data

	Allegheny	Armstrong	Beaver	Bradford	Butler	Cambria	Clarion	Crawford	Fayette	Greene	Indiana	Lawrence	Lycoming	Mercer	Somerset	Sullivan	Susquehanna	Tioga	Washington	Westmoreland	Wyoming	Appendix A Table 11 of the TSD	Appendix A Table 11 of the TSD Discarding Bowers and Sanders	New Analysis
County	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%
Methane	92.65%	83.91%	79.23%	94.06%	81.42%	87.18%	76.96%	88.62%	93.18%	91.51%	95.15%	75.50%	95.14%	54.26%	95.60%	94.46%	95.22%	94.71%	67.26%	93.29%	94.92%	88.78%	91.90%	86.03%
Ethane	6.18%	10.13%	11.39%	4.79%	11.58%	3.71%	12.29%	5.04%	4.21%	6.38%	2.93%	15.37%	4.07%	19.53%	2.81%	4.60%	3.87%	4.40%	17.08%	4.42%	4.13%	5.93%	5.82%	7.93%
Propane	0.41%	2.46%	4.56%	0.34%	3.40%	0.54%	4.79%	1.05%	0.60%	0.68%	0.24%	4.88%	0.24%	11.89%	0.14%	0.32%	0.19%	0.25%	8.09%	0.53%	0.23%	0.88%	0.85%	2.42%
Butane (iso- and n-)	0.08%	0.92%	2.20%	0.05%	1.42%	0.19%	2.43%	0.54%	0.28%	0.13%	0.08%	2.25%	0.03%	7.33%	0.04%	0.08%	0.02%	0.02%	4.14%	0.20%	0.02%	0.27%	0.27%	1.21%
Pentane (iso- and n-)	0.00%	0.24%	0.80%	0.01%	0.44%	0.00%	1.05%	0.48%	0.13%	0.02%	0.01%	0.50%	0.00%	3.24%	0.00%	0.00%	0.00%	0.00%	1.82%	0.06%	0.00%	0.05%	0.05%	0.48%
Hexane and above	0.00%	0.28%	0.50%	0.00%	0.21%	0.02%	1.30%	0.21%	0.17%	0.01%	0.05%	0.39%	0.01%	2.78%	0.00%	0.00%	0.00%	0.00%	0.61%	0.10%	0.00%	0.05%	0.06%	0.36%
Carbon Dioxide	0.19%	0.26%	0.65%	0.08%	1.21%	7.48%	0.09%	0.00%	0.63%	0.82%	0.57%	0.65%	0.04%	0.27%	0.74%	0.05%	0.14%	0.15%	0.37%	0.56%	0.05%	0.21%	0.20%	0.72%
Molecular Nitrogen	0.49%	1.80%	0.66%	0.65%	0.32%	0.87%	1.01%	4.05%	0.80%	0.46%	0.94%	0.46%	0.46%	0.70%	0.65%	0.49%	0.55%	0.45%	0.58%	0.82%	0.62%	3.85%	0.85%	0.85%
Molecular Oxygen	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.07%	0.00%	0.00%	0.00%	0.02%	0.00%	0.00%	0.00%	0.02%	0.00%	0.00%	0.01%	0.03%	0.02%	0.02%	0.00%	0.00%	0.01%
Benzene	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Toluene	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%
Ethylbenzene	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Xylene	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Sum of Parts	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.01%	100.01%	100.00%
VOC (sum of propane and above)	0.49%	3.90%	8.06%	0.41%	5.47%	0.76%	9.57%	2.29%	1.17%	0.84%	0.38%	8.02%	0.28%	25.25%	0.18%	0.41%	0.22%	0.28%	14.67%	0.89%	0.25%	1.25%	1.24%	4.47%
VOC de minimis (TPY)	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Methane de minimis (TPY)	506.8	58.0	26.5	616.3	40.2	310.3	21.7	104.4	214.5	295.0	667.9	25.4	907.0	5.8	1,474.8	629.5	1,189.3	924.9	12.4	282.2	1,012.1	191.6	200.6	51.9
Density of Gas (lb/lb-mol)	16.63	17.41	18.13	16.51	17.81	17.31	18.42	17.01	16.63	16.75	16.44	18.48	16.42	22.05	16.40	16.48	16.41	16.46	19.69	16.60	16.43	16.95	16.71	17.36
Density of Gas (lb/cf)	0.0423	0.0443	0.0461	0.0420	0.0453	0.0441	0.0469	0.0433	0.0423	0.0426	0.0418	0.0470	0.0418	0.0561	0.0417	0.0419	0.0418	0.0419	0.0501	0.0422	0.0418	0.0431	0.0425	0.0442
Average of per County Methane De Minimis					444.0																			

The average composition for the counties with at least one representative gas analysis and the calculated state average gas composition are shown in Table 16. The Department believes that this state average gas composition is representative of the regions where oil and gas operations are occurring. The same process was followed as in the previous analysis, where methane emissions were calculated based on a standard mass-balance and the VOC control threshold of 2.7 tpy for each county. The methane control thresholds ranged from 5.8 tpy for Mercer County and 1,474.8 tpy for Somerset County with an average methane control threshold of 444.0 tpy. While this value is lower than the 714.9 tpy value of the previous analysis, the Department determined that it is unreasonable to be used as a control threshold; this is because it is approximately 15% of the major modification facility threshold for GHG. For the calculated state average composition, the methane control threshold is calculated at 51.9 tpy; this is lower than in the previous calculation because there were more representative gas analyses with VOC weight percentages higher than 2%.

In the first analysis, there were only two samples with VOC weight percentages over 2% and one of them was questionable due to the high nitrogen content; this means only 10% - 17% of the samples had a VOC weight percentage over 2%. In the second analyses, approximately 25% of the samples had VOC weight percentages over 2%; half of those samples had VOC weight percentages over 5% and one had a VOC weight percentage over 25%. This higher VOC weight percentage had the effect of lowering the methane emissions calculated from the mass-balance and increasing the VOC weight percentage of the state average gas composition from 1.25% in the first analysis to 4.47% in the second analysis. The 51.9 tpy methane control threshold calculated from the state average gas composition is approximately 2% of the major modification facility threshold for GHG meaning it is appropriate to use it as a control threshold in the permit. However, as is shown in the analysis in Appendix D for Combustion Control Devices, control of methane at 51.9 tpy is not cost-effective.

XXIII. Appendix B – SCR Cost Analysis for Engines and Turbines

Table 17 - SCR Cost Analysis for 1,380 hp Engine

(All dollar values in 2016 dollars)	Vendor A @ 0.50 g/bhp-h (2016 Quote)	Vendor B @ 0.50 g/bhp-h (2016 Quote)	Vendor C @ 0.50 g/bhp-h (2016 Quote)	Vendor A @ 0.35 g/bhp-h (2016 Quote)	Vendor B @ 0.35 g/bhp-h (2016 Quote)	Vendor C @ 0.35 g/bhp-h (2016 Quote)
SCR Purchased Equipment Costs	\$107,000	\$150,000		\$107,000	\$150,000	
Reductant Tank Purchased Equipment Costs	\$11,000	\$30,000		\$11,000	\$30,000	
Total Purchased Equipment Costs	\$118,000	\$180,000	\$146,000	\$118,000	\$180,000	\$146,000
Freight	\$5,900	\$9,000	\$7,300	\$5,900	\$9,000	\$7,300
Commissioning Costs	\$0	\$0	\$11,500	\$0	\$0	\$11,500
Total Indirect Installation Costs	\$23,600	\$36,000	\$29,200	\$23,600	\$36,000	\$29,200
Project Contingency	\$21,240	\$32,400	\$26,280	\$21,240	\$32,400	\$26,280
Total Plant Cost	\$168,740	\$257,400	\$220,280	\$168,740	\$257,400	\$220,280
Preproduction Cost	\$3,375	\$5,148	\$4,406	\$3,375	\$5,148	\$4,406
Inventory Capital - Initial Fill of Reductant	\$2,500	\$2,500	\$2,500	\$2,500	\$2,500	\$2,500
Total Capital Investment	\$174,615	\$265,048	\$227,186	\$174,615	\$265,048	\$227,186
Operating and Supervisory Labor Costs	\$886	\$886	\$6,716	\$886	\$886	\$6,716
Maintenance Cost	\$2,619	\$3,347	\$3,408	\$2,619	\$3,347	\$3,408
Reductant Consumption Cost	\$18,540	\$18,540	\$24,090	\$18,540	\$18,540	\$24,090
Annual Electricity Cost	\$5,000	\$5,000	\$5,000	\$5,000	\$5,000	\$5,000
Annual Catalyst Replacement Cost	\$11,525	\$11,525	\$22,500	\$11,525	\$11,525	\$22,500
Direct Annual Costs	\$38,570	\$39,297	\$61,714	\$38,570	\$39,297	\$61,714
Indirect Annual Costs	\$16,482	\$25,019	\$21,445	\$16,482	\$25,019	\$21,445
Total Annual Costs	\$55,052	\$64,316	\$83,158	\$55,052	\$64,316	\$83,158
TPY of NO _x Emissions Reduced	5.99	5.99	5.99	4.19	4.19	4.19
Cost Per Ton	\$9,189	\$10,735	\$13,880	\$13,127	\$15,336	\$19,829

Table 18 - SCR Cost Analysis for 4,735 hp Engine

(All dollar values in 2016 dollars)	Vendor A @ 0.50 g/bhp-h (2016 Quote)	Vendor B @ 0.50 g/bhp-h (2016 Quote)	Vendor A @ 0.35 g/bhp-h (2016 Quote)	Vendor B @ 0.35 g/bhp-h (2016 Quote)
SCR Purchased Equipment Costs	\$105,000	\$225,000	\$105,000	\$225,000
Reductant Tank Purchased Equipment Costs	\$20,000	\$50,000	\$20,000	\$50,000
Total Purchased Equipment Costs	\$125,000	\$275,000	\$125,000	\$275,000
Freight	\$6,250	\$13,750	\$6,250	\$13,750
Commissioning Costs	\$0	\$0	\$0	\$0
Total Indirect Installation Costs	\$25,000	\$55,000	\$25,000	\$55,000
Project Contingency	\$22,500	\$49,500	\$22,500	\$49,500
Total Plant Cost	\$178,750	\$393,250	\$178,750	\$393,250
Preproduction Cost	\$3,575	\$7,865	\$3,575	\$7,865
Inventory Capital - Initial Fill of Reductant	\$2,172	\$2,172	\$2,172	\$2,172
Total Capital Investment	\$184,497	\$403,287	\$184,497	\$403,287
Operating and Supervisory Labor Costs	\$1,771	\$1,771	\$1,771	\$1,771
Maintenance Cost	\$2,767	\$6,694	\$2,767	\$6,694
Reductant Consumption Cost	\$37,080	\$37,080	\$37,080	\$37,080
Annual Electricity Cost	\$5,000	\$5,000	\$5,000	\$5,000
Annual Catalyst Replacement Cost	\$23,050	\$23,050	\$23,050	\$23,050
Direct Annual Costs	\$69,668	\$73,595	\$69,668	\$73,595
Indirect Annual Costs	\$17,415	\$38,067	\$17,415	\$38,067
Total Annual Costs	\$87,083	\$111,662	\$87,083	\$111,662
TPY of NO _x Emissions Reduced	20.56	20.56	14.39	14.39
Cost Per Ton	\$4,236	\$5,432	\$6,052	\$7,760

Table 19 - SCR Cost Analysis for Turbines

(All dollar values in 2016 dollars)	Vendor A 1,590 HP 25 ppm NO _x (2016 Quote)	Vendor A 30,000 HP 25 ppm NO _x (2016 Quote)	Vendor B 30,000 HP 25 ppm NO _x (2016 Quote)	Vendor A 30,000 HP 15 ppm NO _x (2016 Quote)	Vendor B 30,000 HP 15 ppm NO _x (2016 Quote)	Vendor A 30,000 HP 9 ppm NO _x (2016 Quote)	Vendor B 30,000 HP 9 ppm NO _x (2016 Quote)
SCR Purchased Equipment Costs	\$514,600	\$932,800	\$2,000,000	\$932,800	\$2,000,000	\$932,800	\$2,000,000
Reductant Tank Purchased Equipment Costs	\$15,000	\$60,000	\$60,000	\$60,000	\$60,000	\$60,000	\$60,000
Total Purchased Equipment Costs	\$529,600	\$992,800	\$2,060,000	\$992,800	\$2,060,000	\$992,800	\$2,060,000
Freight	\$26,480	\$49,640	\$103,000	\$49,640	\$103,000	\$49,640	\$103,000
Commissioning Costs	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Indirect Installation Costs	\$105,920	\$198,560	\$412,000	\$198,560	\$412,000	\$198,560	\$412,000
Project Contingency	\$95,328	\$178,704	\$370,800	\$178,704	\$370,800	\$178,704	\$370,800
Total Plant Cost	\$730,848	\$1,419,704	\$2,945,800	\$1,419,704	\$2,945,800	\$1,419,704	\$2,945,800
Preproduction Cost	\$14,617	\$28,394	\$58,916	\$28,394	\$58,916	\$28,394	\$58,916
Inventory Capital - Initial Fill of Reductant	\$203	\$1,408	\$1,408	\$1,408	\$1,408	\$1,408	\$1,408
Total Capital Investment	\$745,668	\$1,449,506	\$3,006,124	\$1,449,506	\$3,006,124	\$1,449,506	\$3,006,124
Operating and Supervisory Labor Costs	\$6,716	\$6,716	\$6,716	\$6,716	\$6,716	\$6,716	\$6,716
Maintenance Cost	\$11,185	\$21,743	\$45,092	\$21,743	\$45,092	\$21,743	\$45,092
Reductant Consumption Cost	\$2,467	\$17,150	\$17,150	\$17,150	\$17,150	\$17,150	\$17,150
Annual Electricity Cost	\$1,545	\$17,501	\$17,501	\$17,501	\$17,501	\$17,501	\$17,501
Annual Catalyst Replacement Cost	\$20,741	\$138,216	\$138,216	\$138,216	\$138,216	\$138,216	\$138,216
Direct Annual Costs	\$42,654	\$201,326	\$224,675	\$201,326	\$224,675	\$201,326	\$224,675
Indirect Annual Costs	\$70,386	\$136,823	\$283,757	\$136,823	\$283,757	\$136,823	\$283,757
Total Annual Costs	\$113,040	\$338,149	\$508,432	\$338,149	\$508,432	\$338,149	\$508,432
TPY of NO _x Emissions Reduced	6.00	69.38	69.38	41.62	41.62	24.98	24.98
Cost Per Ton	\$18,853	\$4,874	\$7,329	\$8,124	\$12,215	\$13,538	\$20,355

Because the quotes furnished to the Department by the vendors were determined based on the assumption of 8,760 hours of operation, the Department proposes to determine cost effectiveness of the control of NO_x with an SCR system without regard to variability of hours of operation.

The Department proposed to use the average of the total annual costs for each engine size as determined in Table 17 and Table 18 above as a point on a line to determine the cost effectiveness of SCR for sizes for which a quote was not obtained. The reason for using the average total annual cost versus the average cost in dollars per ton is that the emission limit for NO_x emissions for engines rated equal to or less than 500 hp is 1.0 g/bhp-h while for engines rate greater than 500 hp the emission limit for NO_x is 0.5 g/bhp-h. This difference in emission limits would not be reflected using the average cost in dollars per ton, as can be seen in Table 20 below.

Table 20 - Calculated Cost per Ton NO_x Reduced vs Average Cost per Ton NO_x Reduced for Engines

Engine HP (All dollar values in 2016 dollars)	100	250	500	1,000	1,380	1,500	1,875	2,500	3,000	4,735	5,500
Average Total Annual Costs	\$54,650	\$56,097	\$58,509	\$63,334	\$67,000	\$68,158	\$71,777	\$77,807	\$82,632	\$99,373	\$106,754
TPY of NO_x Emissions Reduced	0.87	2.17	4.34	4.34	5.99	6.51	8.14	10.85	13.02	20.56	23.88
Cost Per Ton	\$62,940	\$25,843	\$13,477	\$14,588	\$11,183	\$10,466	\$8,818	\$7,169	\$6,344	\$4,834	\$4,471
Average Cost Per Ton	\$13,603	\$13,320	\$12,847	\$11,901	\$11,182	\$10,955	\$10,245	\$9,063	\$8,117	\$4,834	\$3,387
TPY of NO_x Emissions Reduced, Alternative BAT							5.70	7.60	9.12	14.39	16.71
Alternative Cost Per Ton							\$12,597	\$10,241	\$9,064	\$6,906	\$6,387

The Department proposed that installing an SCR system on lean-burn engines rated at or above 1,875 hp is BAT if the uncontrolled emission rate is 0.50 g/bhp-h, resulting in an emission limit of 0.05 g/bhp-h. However, engine stack test data shows that engines in this size range are capable of achieving an uncontrolled emissions rate of 0.35 g/bhp-h. As can be seen in Table 20 above, SCR is not economically feasible for an engine with uncontrolled emissions rate of 0.35 g/bhp-h until an engine is rated at or above 3,000 hp. Therefore, the Department proposed dual BAT criteria for lean-burn engines rated at or above 1,875 hp and less than 3,000 hp of 0.35 g/bhp-h uncontrolled or 0.05 g/bhp-h with control. The Department proposed a BAT criterion for lean-burn engines rated at or above 3,000 hp of 0.05 g/bhp-h.

Based on additional information submitted and comments received, the Department determined that the installation of SCR should be reevaluated for cost effectiveness. One of the issues raised is that the original BAT cost estimates did not include direct installation costs. Even though the EPA's Air Pollution Control Cost Manual 6th Edition Section 4.2 did not include direct installation costs in Table 2.5, and the 7th Edition Section 4.2 calculates the TCI based on operational parameters, the Department used vendor quotes and the standard cost estimate method from Section 1 of the 6th Edition to calculate cost effectiveness. There appears to be little difference in the method in Section 1 of the 7th Edition except for the use of the bank prime rate of 4.25% for the annualization of capital costs. The Department continues to use the 7% rate from the previous analysis for consistency.

Table 21 - Revised SCR Cost Analyses

(All dollar values in 2016 dollars) ^A	Vendor A 1,380 hp @ 0.50 g/bhp-h	Vendor B 1,380 hp @ 0.50 g/bhp-h	GCA Vendor C ^{1,2} 1,380 hp @ 0.50 g/bhp-h	Vendor C 1,380 hp @ 0.50 g/bhp-h	Vendor A 1,380 hp @ 0.35 g/bhp-h	Vendor B 1,380 hp @ 0.35 g/bhp-h	Vendor C 1,380 hp @ 0.35 g/bhp-h	Cardinal ^{1,2,3} 1,775 hp @ 0.50 g/bhp-h	Cardinal 1,775 hp @ 0.50 g/bhp-h	GCA ^{1,2} 1,775 hp @ 0.50 g/bhp-h	GCA 1,775 hp @ 0.50 g/bhp-h	Vendor A 4,735 hp @ 0.50 g/bhp-h	Vendor B 4,735 hp @ 0.50 g/bhp-h	GCA ⁴ 4,735 hp @ 0.50 g/bhp-h	GCA 4,735 hp @ 0.50 g/bhp-h
SCR System	\$107,000	\$150,000	\$146,000	\$146,000	\$107,000	\$150,000	\$146,000	\$152,484	\$152,484	\$130,000	\$130,000	\$105,000	\$225,000	\$495,685	\$495,685
Reductant Tank and Other Auxiliary Equipment	\$11,000	\$30,000	\$0	\$0	\$11,000	\$30,000	\$0	\$37,043	\$37,043	\$0	\$0	\$20,000	\$50,000	\$58,257	\$58,257
Customer Supplied Equipment	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Instrumentation	\$0	\$0	\$14,600	\$0	\$0	\$0	\$0	\$16,110	\$0	\$13,000	\$0	\$0	\$0	\$0	\$0
Initial Fill of Reductant	\$711	\$711	\$2,500	\$3,960	\$498	\$498	\$3,960	\$5,000	\$5,000	\$2,500	\$3,600	\$2,440	\$2,440	\$9,750	\$3,024
Freight	\$5,936	\$9,036	\$7,300	\$7,498	\$5,925	\$9,025	\$7,498	\$10,532	\$9,726	\$6,500	\$6,680	\$6,372	\$13,872	\$13,750	\$27,848
Total Purchased Equipment Costs	\$124,647	\$189,747	\$170,400	\$157,458	\$124,423	\$189,523	\$157,458	\$221,169	\$204,253	\$152,000	\$140,280	\$133,812	\$291,312	\$577,442	\$584,814
Total Direct Installation Costs	\$162,041	\$246,671	\$131,400	\$204,695	\$161,750	\$246,380	\$204,695	\$144,989	\$265,529	\$117,000	\$182,364	\$173,956	\$378,706	\$0	\$760,259
Commissioning Costs	\$0	\$0	\$11,500	\$11,500	\$0	\$0	\$11,500	\$100,000	\$100,000	\$11,500	\$11,500	\$0	\$0	\$0	\$0
Total Indirect Installation Costs	\$38,640	\$58,821	\$58,878	\$48,812	\$38,571	\$58,752	\$48,812	\$113,030	\$63,319	\$52,450	\$43,487	\$41,482	\$90,307	\$463,072	\$181,292
Total Capital Investment	\$200,681	\$305,492	\$372,178	\$265,007	\$200,321	\$305,132	\$265,007	\$548,284	\$428,848	\$332,950	\$237,351	\$215,437	\$469,012	\$1,040,514	\$941,551
Operating and Supervisory Labor Costs	\$5,009	\$2,362	\$65,000	\$5,009	\$5,009	\$2,362	\$5,009	\$62,400	\$5,009	\$65,000	\$5,009	\$5,009	\$4,723	\$21,000	\$5,009
Maintenance Cost	\$9,583	\$3,347	\$3,722	\$9,583	\$9,583	\$3,347	\$9,583	\$8,224	\$9,583	\$3,330	\$9,583	\$9,583	\$6,694	\$37,500	\$9,583
Reductant Consumption Cost	\$4,326	\$18,540	\$24,090	\$24,090	\$3,028	\$18,540	\$24,090	\$8,760	\$8,760	\$24,090	\$21,900	\$14,843	\$37,080	\$18,396	\$14,843
Annual Electricity Cost	\$3,524	\$3,524	\$5,000	\$3,524	\$3,524	\$3,524	\$3,524	\$5,807	\$3,993	\$5,000	\$3,993	\$10,551	\$10,551	\$5,000	\$10,551
Annual Catalyst Replacement Cost	\$14,248	\$11,614	\$22,500	\$14,248	\$14,023	\$11,614	\$14,023	\$20,000	\$8,078	\$18,000	\$14,827	\$22,371	\$23,227	\$47,388	\$22,371
Direct Annual Costs	\$36,690	\$39,387	\$120,312	\$56,454	\$35,167	\$39,387	\$56,229	\$105,191	\$35,423	\$115,420	\$55,312	\$62,357	\$82,275	\$129,284	\$62,357
Overhead	\$11,351	\$14,549	\$0	\$23,209	\$10,572	\$14,549	\$23,209	\$0	\$14,011	\$0	\$21,895	\$17,661	\$29,098	\$0	\$17,661
Administrative Charges	\$4,014	\$6,110	\$0	\$5,300	\$4,006	\$6,103	\$5,300	\$0	\$8,577	\$0	\$4,747	\$4,309	\$9,380	\$0	\$18,831
Property Tax	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Insurance	\$2,007	\$3,055	\$0	\$2,650	\$2,003	\$3,051	\$2,650	\$0	\$4,288	\$0	\$2,374	\$2,154	\$4,690	\$0	\$9,416
Capital Recovery	\$18,942	\$28,835	\$40,861	\$25,014	\$18,908	\$28,801	\$25,014	\$89,233	\$40,479	\$36,555	\$22,404	\$20,335	\$44,270	\$98,214	\$88,873
Indirect Annual Costs	\$36,314	\$52,550	\$40,861	\$56,173	\$35,490	\$52,505	\$56,173	\$89,233	\$67,356	\$36,555	\$51,419	\$44,459	\$87,439	\$98,214	\$134,781
Total Annual Costs	\$73,004	\$91,937	\$161,173	\$112,627	\$70,657	\$91,892	\$112,402	\$194,424	\$102,779	\$151,975	\$106,731	\$106,816	\$169,714	\$227,498	\$197,138
TPY of NO _x Emissions Reduced	5.99	5.99	5.99	5.99	4.19	4.19	4.19	7.71	7.71	7.71	7.71	20.56	20.56	20.56	20.56
Cost Per Ton	\$12,185	\$15,345	\$26,902	\$18,799	\$16,848	\$21,911	\$26,802	\$25,230	\$13,337	\$19,722	\$13,850	\$5,196	\$8,256	\$11,067	\$9,590
TPY of All Polutants Emissions Reduced								55.63	55.63						
Cost Per Ton								\$3,495	\$1,848						

¹ Quote included instrumentation.

² Company used interest rate and/or equipment life different than EPA directed 7.0% interest rate and 20 years equipment life.

³ Quote included oxidation catalyst.

⁴ Company made arithmetic error; listed PEC as \$517,942 when \$495,685 + \$58,257 = \$553,942.

^A The Department orginally used the Capital Cost Factors from Table 2.5 in the October 2000 version of the Control Cost Manual. The updated chapter uses a base equation to calculate TCI. The Department uses the base OAQPS calculation method in the reanalysis, which may result in an overestimation of cost.

Table 22 - Revised SCR Cost Analyses

(All dollar values in 2016 dollars) ^A	INGAA 1 ^{1,2,5,6,7} 4,735 hp @ 0.35 g/bhp-h	INGAA 1 4,735 hp @ 0.35 g/bhp-h	INGAA 2 ^{1,2,5,6,7} 4,735 hp @ 0.35 g/bhp-h	INGAA 2 4,735 hp @ 0.35 g/bhp-h	Vendor A 4,735 hp @ 0.35 g/bhp-h	Vendor B 4,735 hp @ 0.35 g/bhp-h	GCA ^{4,7} 4,735 hp @ 0.30 g/bhp-h	GCA 4,735 hp @ 0.30 g/bhp-h	MarkWest ^{1,2,3,7,8} 5,350 hp @ 0.30 g/bhp-h	MarkWest ⁹ 5,350 hp @ 0.30 g/bhp-h	MarkWest ^{1,2,7,8,10} 5,350 hp @ 0.30 g/bhp-h Revised	MarkWest ^{9,10} 5,350 hp @ 0.30 g/bhp-h	MarkWest ^{1,2,7,10} 5,350 hp @ 0.30 g/bhp-h No OxyCat	MarkWest ^{9,10} 5,350 hp @ 0.30 g/bhp-h No OxyCat
SCR System	\$225,000	\$225,000	\$277,000	\$227,000	\$105,000	\$225,000	\$495,685	\$495,685	\$245,790	\$245,790	\$226,290	\$226,290	\$226,290	\$226,290
Reductant Tank and Other Auxiliary Equipment	\$0	\$50,000	\$0	\$50,000	\$20,000	\$50,000	\$58,257	\$58,257	\$13,253	\$15,593	\$13,253	\$15,593	\$13,253	\$15,593
Customer Supplied Equipment	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$28,200	\$28,200	\$28,200	\$25,963	\$28,200	\$25,963
Instrumentation	\$85,000	\$0	\$27,700	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Initial Fill of Reductant	\$0	\$1,708	\$0	\$1,708	\$1,708	\$1,708	\$9,750	\$1,464	\$5,000	\$5,000	\$5,000	\$5,000	\$5,000	\$5,000
Freight	\$11,250	\$13,835	\$0	\$13,935	\$6,335	\$13,835	\$13,750	\$27,770	\$15,000	\$14,729	\$15,000	\$13,642	\$15,000	\$13,642
Total Purchased Equipment Costs	\$330,550	\$290,543	\$304,700	\$292,643	\$133,043	\$290,543	\$577,442	\$583,176	\$307,243	\$309,312	\$287,743	\$286,488	\$287,743	\$286,488
Total Direct Installation Costs	\$429,715	\$377,706	\$987,700	\$380,436	\$172,956	\$377,706	\$0	\$758,129	\$365,981	\$454,847	\$365,981	\$420,991	\$313,240	\$372,434
Commissioning Costs	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$30,875	\$30,875	\$30,875	\$28,426	\$30,875	\$30,875
Total Indirect Installation Costs	\$69,416	\$90,068	\$157,173	\$90,719	\$41,243	\$90,068	\$463,072	\$180,785	\$133,945	\$95,887	\$133,945	\$88,811	\$133,945	\$88,811
Total Capital Investment	\$499,131	\$467,775	\$1,144,873	\$471,156	\$214,200	\$467,775	\$1,040,514	\$938,914	\$838,044	\$581,609	\$818,544	\$538,228	\$765,803	\$492,121
Operating and Supervisory Labor Costs	\$14,375	\$5,009	\$14,375	\$5,009	\$5,009	\$5,009	\$21,000	\$5,009	\$0	\$5,009	\$0	\$5,009	\$0	\$5,009
Maintenance Cost	\$17,500	\$9,583	\$17,500	\$9,583	\$9,583	\$9,583	\$37,500	\$9,583	\$0	\$9,583	\$0	\$9,583	\$0	\$9,583
Reductant Consumption Cost	\$37,000	\$10,390	\$37,000	\$10,390	\$10,390	\$10,390	\$18,396	\$8,906	\$0	\$17,520	\$0	\$17,520	\$0	\$17,520
Annual Electricity Cost	\$5,000	\$10,551	\$5,000	\$10,551	\$10,551	\$10,551	\$5,000	\$10,551	\$0	\$11,856	\$0	\$11,856	\$0	\$11,856
Annual Catalyst Replacement Cost	\$23,050	\$21,984	\$23,050	\$21,984	\$21,984	\$21,984	\$47,388	\$21,855	\$0	\$37,668	\$0	\$37,668	\$0	\$18,834
Direct Annual Costs	\$116,925	\$57,517	\$116,925	\$57,517	\$57,517	\$57,517	\$129,284	\$55,904	\$85,000	\$81,636	\$85,000	\$81,636	\$85,000	\$62,802
Overhead	\$19,125	\$14,989	\$19,125	\$14,989	\$14,989	\$14,989	\$0	\$14,099	\$0	\$19,267	\$0	\$19,267	\$0	\$19,267
Administrative Charges	\$9,983	\$9,355	\$22,897	\$9,423	\$4,284	\$9,355	\$0	\$18,778	\$0	\$11,632	\$0	\$10,765	\$0	\$9,842
Property Tax	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Insurance	\$4,991	\$4,678	\$11,449	\$4,712	\$2,142	\$4,678	\$0	\$9,389	\$0	\$5,816	\$0	\$5,382	\$0	\$4,921
Capital Recovery	\$81,234	\$44,153	\$186,328	\$44,472	\$20,218	\$44,153	\$98,214	\$88,624	\$0	\$54,898	\$0	\$50,803	\$0	\$46,451
Indirect Annual Costs	\$120,321	\$73,176	\$251,243	\$73,596	\$41,634	\$73,176	\$98,214	\$130,890	\$134,386	\$91,613	\$166,483	\$86,217	\$159,235	\$80,482
Total Annual Costs	\$237,246	\$130,693	\$368,168	\$131,113	\$99,151	\$130,693	\$227,498	\$186,794	\$219,386	\$173,249	\$251,483	\$167,853	\$244,235	\$143,284
TPY of NO _x														
Emissions Reduced	13.70	14.39	13.70	14.39	14.39	14.39	11.74	12.33	12.90	13.94	12.90	13.94	12.90	13.94
Cost Per Ton	\$17,315	\$9,082	\$26,869	\$9,112	\$6,890	\$9,082	\$19,370	\$15,145	\$17,009	\$12,432	\$19,497	\$12,045	\$18,935	\$10,282
TPY of All Pollutants Emissions Reduced									133.27	134.31				
Cost Per Ton									\$1,646	\$1,290				

¹ Quote included instrumentation.

² Company used interest rate and/or equipment life different than EPA directed 7.0% interest rate and 20 years equipment life.

³ Quote included oxidation catalyst.

⁴ Company made arithmetic error; listed PEC as \$517,942 when \$495,685 + \$58,257 = \$553,942.

⁵ Company included sales tax in their calculation. Under 61 Pa. Code §32.35, pollution control devices are exempt from tax in mining operations, which includes oil and gas drilling. Under 61 Pa. Code §155.11, pollution control devices are deductible from property tax calculations.

⁶ Company included \$20,000 Testing and QA/QC costs in the Direct Annual Costs.

⁷ Calculated NO_x reduction to limit of 0.05 g/bhp-h rather than by 90% control.

⁸ Site Preparation Costs of \$52,741 were included.

⁹ The Department included the additional \$2,340 for the Maintenance Pack listed in the scope of supply.

¹⁰ The oxidation catalyst costs were removed from the system cost; however, the company did not pro-rate any other costs in their analysis. The Department prorated all costs based on the ratio of costs for the oxidation catalyst to the SCR system.

^A The Department originally used the Capital Cost Factors from Table 2.5 in the October 2000 version of the Control Cost Manual. The updated chapter uses a base equation to calculate TCI. The Department uses the base OAQPS calculation method in the reanalysis, which may result in an overestimation of cost.

Table 23 - Derivation of Average Total Annual Cost Parameters

Quote Source	Purchased Equipment Costs	Engine Rating (HP)	NOx Emission Factor (g/bhp-h)	SCR Control Efficiency	Interest Rate	Equipment Life (years)	Total Annual Cost	Estimation Method	NOx Emissions Reduced (tons)	Cost Effectiveness (\$/ton reduced)	Total Emissions Reduced (tons)	Cost Effectiveness (\$/ton reduced)
Vendor A	\$118,000	1,380	0.50	90.0%	7.0%	20	\$55,052	First TSD Analysis	5.99	\$9,189		
Vendor A	\$118,000	1,380	0.50	90.0%	7.0%	20	\$73,004	OAQPS (Revised)	5.99	\$12,185		
Vendor B	\$180,000	1,380	0.50	90.0%	7.0%	20	\$64,316	First TSD Analysis	5.99	\$10,735		
Vendor B	\$180,000	1,380	0.50	90.0%	7.0%	20	\$91,937	OAQPS (Revised)	5.99	\$15,345		
GCA Vendor C	\$146,000	1,380	0.50	90.0%	7.0%	15	\$161,173	Company OAQPS Based	5.99	\$26,902		
Vendor C	\$146,000	1,380	0.50	90.0%	7.0%	20	\$83,158	First TSD Analysis	5.99	\$13,880		
Vendor C	\$146,000	1,380	0.50	90.0%	7.0%	20	\$112,627	OAQPS (Revised)	5.99	\$18,799		
Vendor A	\$118,000	1,380	0.35	90.0%	7.0%	20	\$55,052	First TSD Analysis	4.19	\$13,127		
Vendor A	\$118,000	1,380	0.35	90.0%	7.0%	20	\$70,657	OAQPS (Revised)	4.19	\$16,848		
Vendor B	\$180,000	1,380	0.35	90.0%	7.0%	20	\$64,316	First TSD Analysis	4.19	\$15,336		
Vendor B	\$180,000	1,380	0.35	90.0%	7.0%	20	\$91,892	OAQPS (Revised)	4.19	\$21,911		
Vendor C	\$146,000	1,380	0.35	90.0%	7.0%	20	\$83,158	First TSD Analysis	4.19	\$19,829		
Vendor C	\$146,000	1,380	0.35	90.0%	7.0%	20	\$112,402	OAQPS (Revised)	4.19	\$26,802		
Cardinal	\$189,527	1,775	0.50	90.0%	10.0%	10	\$194,424	Company Quote	7.71	\$25,230	55.11	\$3,528
Cardinal	\$189,527	1,775	0.50	90.0%	7.0%	20	\$102,779	OAQPS (Revised)	7.71	\$13,338	55.11	\$1,865
GCA	\$130,000	1,775	0.50	90.0%	7.0%	15	\$151,975	Company Quote	7.71	\$19,722		
GCA	\$130,000	1,775	0.50	90.0%	7.0%	20	\$106,731	OAQPS (Revised)	7.71	\$13,850		
Vendor A	\$125,000	4,735	0.50	90.0%	7.0%	20	\$87,083	TSD	20.56	\$4,236		
Vendor A	\$125,000	4,735	0.50	90.0%	7.0%	20	\$106,816	OAQPS (Revised)	20.56	\$5,196		
Vendor B	\$275,000	4,735	0.50	90.0%	7.0%	20	\$111,662	TSD	20.56	\$5,432		
Vendor B	\$275,000	4,735	0.50	90.0%	7.0%	20	\$169,714	OAQPS (Revised)	20.56	\$8,256		
GCA	\$553,942	4,735	0.50	90.0%	7.0%	20	\$227,498	Company TSD Method	20.56	\$11,067		
GCA	\$553,942	4,735	0.50	90.0%	7.0%	20	\$197,138	OAQPS (Revised)	20.56	\$9,590		
INGAA	\$310,000	4,735	0.35	85.7%	10.0%	10	\$237,246	Company OAQPS Based	13.70	\$17,315		
INGAA	\$275,000	4,735	0.35	90.0%	7.0%	20	\$130,693	OAQPS (Revised)	14.39	\$9,082		
INGAA	\$304,700	4,735	0.35	85.7%	10.0%	10	\$368,168	Company Quote	13.70	\$26,869		
INGAA	\$277,000	4,735	0.35	90.0%	7.0%	20	\$131,113	Company Quote	14.39	\$9,112		
Vendor A	\$125,000	4,735	0.35	90.0%	7.0%	20	\$87,083	TSD	14.39	\$6,052		
Vendor A	\$125,000	4,735	0.35	90.0%	7.0%	20	\$99,151	OAQPS (Revised)	14.39	\$6,890		
Vendor B	\$275,000	4,735	0.35	90.0%	7.0%	20	\$111,662	TSD	14.39	\$7,760		
Vendor B	\$275,000	4,735	0.35	90.0%	7.0%	20	\$130,693	OAQPS (Revised)	14.39	\$9,082		
GCA	\$553,942	4,735	0.30	85.7%	7.0%	20	\$227,498	Company TSD Method	11.74	\$19,370		
GCA	\$553,942	4,735	0.30	90.0%	7.0%	20	\$186,794	OAQPS (Revised)	12.33	\$15,145		
MarkWest	\$287,243	5,350	0.30	83.3%	6.0%	20	\$219,386	Company Quote	12.90	\$17,009	133.27	\$1,646
MarkWest	\$289,583	5,350	0.30	90.0%	7.0%	20	\$173,249	OAQPS (Revised)	13.94	\$12,432	134.31	\$1,290
MarkWest	\$267,743	5,350	0.30	83.3%	7.0%	20	\$251,483	Company Revised Quote	12.90	\$19,497		
MarkWest	\$267,846	5,350	0.30	90.0%	7.0%	20	\$167,853	OAQPS (Revised)	13.94	\$12,045		
MarkWest	\$267,743	5,350	0.30	83.3%	7.0%	20	\$244,235	Company Revised Quote	12.90	\$18,935		
MarkWest	\$267,846	5,350	0.30	90.0%	7.0%	20	\$143,284	OAQPS (Revised)	13.94	\$10,282		

Engine Rating (HP)	Average Total Annual Cost
1,380	\$86,057
1,380	\$79,798
1,775	\$138,977
1,775	\$104,755
4,735	\$163,126
4,735	\$143,186
5,530	\$199,915
5,530	\$196,021

m	\$28.01
b	\$41,150

Table 24 - Calculated SCR Cost Effectiveness

Engine Rating (HP)	Caterpillar Model	Emission Rate	Emissions Reduced (90% Reduction)	Estimated Annual Cost	\$/ton reduced
100		1.0	0.87	\$43,951	\$50,618
145	G3306	0.5	0.63	\$45,211	\$71,821
250		1.0	2.17	\$48,153	\$22,183
255	G3408	0.5	1.11	\$48,293	\$43,622
425	G3408C	0.5	1.85	\$53,054	\$28,754
500		1.0	4.34	\$55,155	\$12,704
524	G3508	0.5	2.27	\$55,827	\$24,541
690	G3508B	0.5	3.00	\$60,477	\$20,189
790	G3512	0.5	3.43	\$63,278	\$18,450
1,000		0.5	4.34	\$69,160	\$15,930
1,035	G3512B	0.5	4.49	\$70,140	\$15,610
1,380	G3516B	0.5	5.99	\$79,804	\$13,320
1,480	G3520B	0.5	6.43	\$82,605	\$12,856
1,500		0.5	6.51	\$83,165	\$12,771
1,775	G3606	0.5	7.71	\$90,868	\$11,792
1,875	G3606A4	0.3	4.88	\$93,669	\$19,178
2,370	G3608	0.5	10.29	\$107,534	\$10,451
2,500	G3608A4	0.3	6.51	\$111,175	\$17,072
3,000		0.5	13.02	\$125,180	\$9,611
3,550	G3612	0.5	15.41	\$140,586	\$9,122
3,750	G3612A4	0.3	9.77	\$146,188	\$14,966
4,735	G3616	0.5	20.56	\$173,777	\$8,454
5,350	G3616A4	0.3	13.94	\$191,004	\$13,706
5,500		0.5	23.88	\$195,205	\$8,175
6,135	G12CM34	0.5	26.63	\$212,991	\$7,997
8,180	G16CM34	0.5	35.51	\$270,272	\$7,611
6,135		0.3	15.98	\$212,991	\$13,328
8,180		0.3	21.31	\$270,272	\$12,684

Based on the costs determined in Table 24 above, and the cost-effectiveness threshold of \$10,000 per ton of NO_x reduced, SCR is cost effective for engines greater than or equal to 2,370 hp if the starting NO_x emission rate is 0.50 g/bhp-h. Installation of SCR becomes economically infeasible for engines greater than or equal to 2,370 hp if the starting NO_x emission rate is 0.30 g/bhp-h. For this reason, the Department proposes a dual BAT criterion for lean burn engines greater than or equal to 2,370 hp of 0.30 g/bhp-h NO_x uncontrolled, or 0.05 g/bhp-h NO_x with control.

Following the original methodology described above for engines with the turbine data results in cost per ton and average cost per ton as summarized in Table 5 below. The BAT emissions limits of 25 ppm for NO_x for turbines below 5,000 bhp, of 15 ppm for turbines 5,000 bhp and above were used in the analysis.

Table 25 - Calculated Cost per Ton NO_x Reduced vs Average Cost per Ton NO_x Reduced for Turbines using BAT Emissions

Turbine HP (All dollar values in 2016 dollars)	1,000	1,590	3,000	5,000	6,130	7,500	11,150	15,900	17,500	20,000	25,000	30,000
Average Total Annual Costs	\$107,277	\$113,040	\$130,449	\$153,621	\$166,713	\$182,586	\$224,875	\$279,908	\$298,446	\$327,411	\$385,341	\$423,291
TPY of NO_x Emissions Reduced, Uncontrolled	6.79	6.00	11.22	15.66	18.95	21.21	29.15	42.75	43.39	48.93	60.02	69.38
Uncontrolled Cost Per Ton	\$15,804	\$18,853	\$11,622	\$9,810	\$8,799	\$8,611	\$7,714	\$6,547	\$6,879	\$6,691	\$6,420	\$6,101
Average Cost Per Ton	\$15,912	\$15,933	\$15,987	\$16,062	\$16,104	\$16,155	\$16,292	\$16,470	\$16,530	\$16,624	\$16,812	\$16,999
TPY of NO_x Emissions Reduced, BAT	6.79	6.00	11.22	9.40	11.37	12.72	17.49	25.65	26.03	29.36	36.01	41.62
BAT Cost Per Ton	\$15,804	\$18,853	\$11,622	\$16,351	\$14,665	\$14,352	\$12,858	\$10,913	\$11,466	\$11,153	\$10,701	\$10,170
TPY of NO_x Emissions Reduced, Alternative BAT								15.39	15.62	17.62	21.61	24.98
Alternative Cost Per Ton								\$18,184	\$19,106	\$18,585	\$17,832	\$16,946

For turbines rated at 5,000 hp and above with uncontrolled emissions of 25 ppm NO_x, SCR is cost effective. However, for turbines rated 5,000 hp and above but below 15,900 hp and operating at 15 ppm NO_x uncontrolled, SCR is not cost effective. Therefore, for turbines rated at or above 5,000 hp and below 15,900 hp, the Department proposes an emission limit of 15 ppm NO_x. For turbines rated at or above 15,900 hp, SCR is cost effective even when the uncontrolled emission rate is 15 ppm NO_x. However, a recently issued permit in New York establishes a NO_x emission limit of 9 ppm for two Solar Mars Turbines which, according to the Solar Turbines website, are rated at 15,900 bhp. A recent plan approval application to the Department also proposes 9 ppm NO_x for combustion turbines. Based on the availability of these low-emission models, the Department proposes an emission limit of 9 ppm NO_x uncontrolled or 1.5 ppm NO_x with control for turbines greater than 15,900 hp.

XXIV. Appendix C – Oxidation Catalyst and NSCR Cost Analysis for Engines and Turbines

Unlike the methodology used in Appendix B – SCR Cost Analysis for Engines and Turbines for SCR, the Department relied on a memorandum from E^{C/R} Incorporated dated June 29, 2010, to Melanie King at EPA OAQPS/SPPD/ESG for engine emission control devices. The memorandum determined a linear equation for total annual cost for oxidation catalysts for lean-burn engines. The Department then calculated the cost per ton based on weighted average emission rates and on BAT emission rates.

Table 26 - Oxidation Catalyst Cost Analysis for Lean-Burn Engines - Weighted Average Emissions

Engine HP (All dollar values in 2016 dollars)	100	250	500	1,000	1,380	1,500	1,875	2,370	2,500	3,500	4,735	5,500
Total Annual Costs	\$4,058	\$4,362	\$4,869	\$5,882	\$6,653	\$6,896	\$7,656	\$8,660	\$8,923	\$10,950	\$13,454	\$15,005
TPY of CO Emissions Reduced	5.82	14.54	8.68	17.37	23.96	26.05	34.19	43.21	45.58	63.82	86.34	100.29
TPY of NMNEHC Emissions Reduced	0.29	0.72	1.21	2.41	3.33	3.62	7.24	9.15	9.65	13.51	18.27	21.22
Cost Per Ton	\$664	\$286	\$492	\$297	\$244	\$232	\$185	\$165	\$162	\$142	\$129	\$123

Table 27 - Oxidation Cost Analysis for Lean-Burn Engines - BAT Emissions

Engine HP (All dollar values in 2016 dollars)	100	250	500	1,000	1,380	1,500	1,875	2,370	2,500	3,500	4,735	5,500
Total Annual Costs	\$4,058	\$4,362	\$4,869	\$5,882	\$6,653	\$6,896	\$7,656	\$8,660	\$8,923	\$10,950	\$13,454	\$15,005
TPY of CO Emissions Reduced	1.74	4.34	1.74	3.47	4.79	5.21	6.51	8.23	8.68	12.16	16.45	19.10
TPY of NMNEHC Emissions Reduced	0.34	0.84	0.60	1.21	1.66	1.81	2.26	2.86	3.01	4.22	5.71	6.63
Cost Per Ton	\$1,956	\$841	\$2,081	\$1,257	\$1,030	\$983	\$873	\$781	\$763	\$669	\$607	\$583

The same memorandum also determined a linear equation for the total annual cost for NSCR for rich-burn engines. As for lean-burn engines, the Department calculated the cost per ton for NSCR on rich-burn engines using the cost per ton based on weighted average emission rates and on BAT emission rates.

Table 28 - NSCR Cost Analysis for Rich-Burn Engines - Weighted Average Emissions

Engine HP (All dollar values in 2016 dollars)	100	250	500	1,000	1,380	1,500	2,500	3,500	4,735	5,500
Total Annual Costs	\$6,895	\$7,696	\$9,032	\$11,703	\$13,733	\$14,374	\$19,716	\$25,059	\$31,657	\$35,744
TPY of NO_x Emissions Reduced	14.57	36.43	70.57	141.14	194.78	211.72	352.86	494.00	668.32	776.29
TPY of CO Emissions Reduced	7.61	19.02	37.58	75.15	103.71	112.73	187.89	263.04	355.86	413.35
TPY of NMNEHC Emissions Reduced	0.14	0.36	0.72	1.45	2.00	2.17	3.62	5.06	6.85	7.96
Cost Per Ton	\$309	\$138	\$83	\$54	\$46	\$44	\$36	\$33	\$31	\$30

Table 29 - NSCR Cost Analysis for Rich-Burn Engines - BAT Emissions

Engine HP (All dollar values in 2016 dollars)	100	250	500	1,000	1,380	1,500	2,500	3,500	4,735	5,500
Total Annual Costs	\$6,895	\$7,696	\$9,032	\$11,703	\$13,733	\$14,374	\$19,716	\$25,059	\$31,657	\$35,744
TPY of NO_x Emissions Reduced	0.23	0.57	0.92	1.83	2.53	2.75	4.58	6.42	8.68	10.08
TPY of CO Emissions Reduced	0.27	0.69	1.37	2.75	3.79	4.12	6.87	9.62	13.02	15.12
TPY of NMNEHC Emissions Reduced	0.10	0.24	0.48	0.96	1.33	1.45	2.41	3.38	4.57	5.31
Cost Per Ton	\$11,480	\$5,126	\$3,256	\$2,110	\$1,794	\$1,727	\$1,422	\$1,291	\$1,205	\$1,172

For lean-burn engines, using both the weighted average emissions and the BAT emissions, the cost effectiveness of control was less than the cost-effectiveness threshold of \$5,000 per ton of pollutant reduced was shown for engines rated at 100 bhp and above. Therefore, the Department determines that oxidation catalysts are required for all lean-burn engines rated greater than or equal to 100 bhp.

For rich-burn engines, using the BAT emissions shows that NSCR is not cost effective below 250 hp; however, NSCR was previously established as BAT for rich-burn engines rated greater than or equal to 100 bhp. Therefore, the Department determines that NSCR is required for all rich burn engines rated greater than or equal to 100 bhp.

Table 30 - Turbine Characteristics and Emissions Data

	Turbine A	Turbine B	Turbine C	Turbine D	Turbine E
Power (bhp)	1,590	6,130	11,150	15,900	30,000
Heat Rate (Btu/bhp-h)	10,370	8,500	7,190	7,395	6,360
Exhaust Flow (lb/h)	51,615	149,380	215,990	337,850	541,590
Exhaust Temperature (°F)	970	960	935	905	865
Heat Input (MMBtu/h)	16.49	52.11	80.17	117.58	190.80
Exhaust Flow (scfh)	720,747	2,085,927	3,016,063	4,717,703	7,562,708
Exhaust Flow (acfm)	32,411	93,145	132,308	202,505	315,113
NO _x Emission Rate (ppm)	2.50E-05	1.50E-05	1.50E-05	9.00E-06	9.00E-06
NO _x Emission Rate (lb/MMBtu)	0.09224	0.05534	0.05534	0.03321	0.03321
NO _x Emission Rate (tpy)	6.66	12.63	19.43	17.10	27.75
CO Emission Rate (ppm)	2.50E-05	2.50E-05	2.50E-05	1.00E-05	1.00E-05
CO Emission Rate (lb/MMBtu)	0.05607	0.05607	0.05607	0.02243	0.02243
CO Emission Rate (tpy)	4.05	12.80	19.69	11.55	18.74
NMNEHC Emission Rate (ppm)	9.00E-06	9.00E-06	9.00E-06	5.00E-06	5.00E-06
NMNEHC Emission Rate (lb/MMBtu)	0.03179	0.03179	0.03179	0.01766	0.01766
NMNEHC Emission Rate (tpy)	2.30	7.25	11.16	9.09	14.76

Unfortunately, a convenient analysis for oxidation catalysts for turbines was not found. Instead, the Department relied on vendor quotes and performed an analysis similar to the one for SCR in Appendix B – SCR Cost Analysis for Engines and Turbines. Three independent quotes were given for different sized turbines, and those formed the basis for the extrapolation of total annual costs for turbines of other sizes.

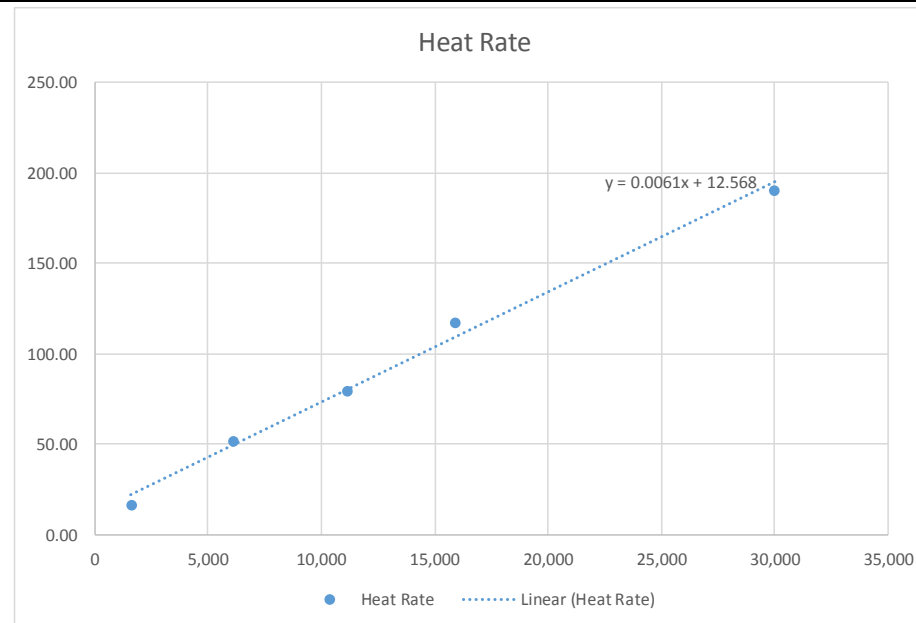


Table 31 - Oxidation Catalyst Cost Data for Turbines

(All dollar values in 2016 dollars)	6,130	15,900	30,000
Oxidation Catalyst Purchased Equipment Costs	\$96,785	\$205,918	\$215,090
Direct Installation Costs (0.30PEC)	\$29,035	\$61,775	\$64,527
Total Indirect Installation Costs (0.27PEC)	\$26,132	\$55,598	\$58,074
Project Contingency (0.15(DIC+IIC))	\$8,275	\$17,606	\$18,390
Total Capital Investment	\$160,227	\$340,897	\$356,082
Operating and Supervisory Labor Costs	\$18,889	\$18,889	\$18,889
Maintenance Cost	\$2,904	\$6,178	\$6,453
Natural Gas Penalty	\$12,553	\$28,325	\$45,964
Catalyst Disposal	\$130	\$338	\$637
Annual Catalyst Replacement Cost	\$14,204	\$36,841	\$69,512
Direct Annual Costs	\$48,679	\$90,570	\$141,454
Indirect Annual Costs	\$34,609	\$60,854	\$63,060
Total Annual Costs	\$83,288	\$151,424	\$204,514



The uncontrolled emissions rates assume 25 ppm for CO and total hydrocarbons, which when adjusted to NMNEHC as propane becomes 9 ppm. The BAT emissions rates, in ppm, were taken from the previous GP-5. The values for CO and NMNEHC are used in the table below for the turbine oxidation catalyst cost analysis.

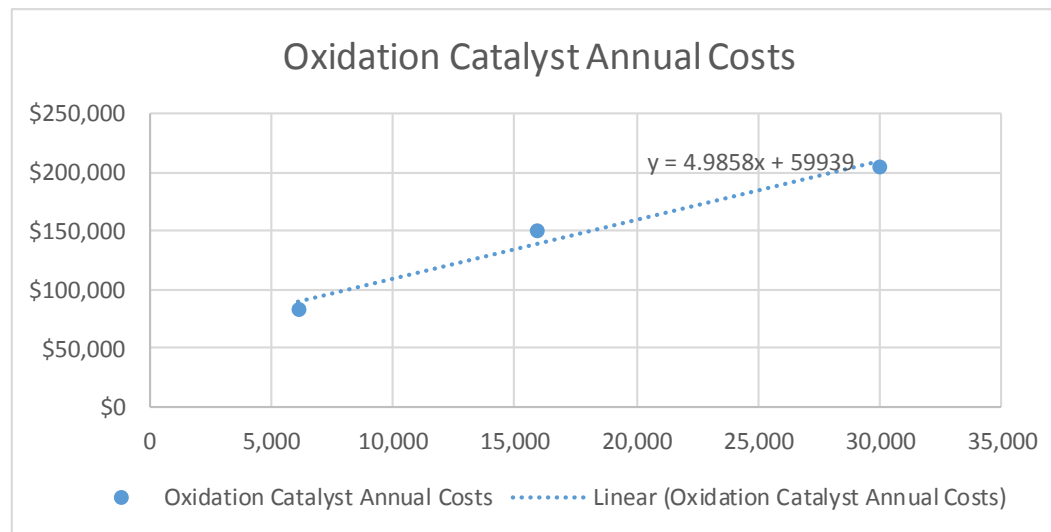


Table 32 – Oxidation Catalyst Cost Analysis for Turbines - Uncontrolled Emissions

Turbine HP (All dollar values in 2016 dollars)	1,000	1,590	3,000	5,000	6,130	7,500	11,150	15,900	17,500	20,000	25,000	30,000
Total Annual Costs	\$64,925	\$67,866	\$74,896	\$84,868	\$83,288	\$97,333	\$115,531	\$151,424	\$147,191	\$159,655	\$184,584	\$204,514
TPY of CO Emissions Reduced	4.26	3.77	7.05	9.84	11.90	13.32	18.31	26.85	27.25	30.73	37.70	43.58
TPY of NMNEHC Emissions Reduced	1.30	1.15	2.15	3.00	3.63	4.06	5.58	8.19	8.31	9.37	11.49	13.62
Cost Per Ton	\$11,670	\$13,810	\$8,142	\$6,612	\$5,363	\$5,600	\$4,836	\$4,321	\$4,139	\$3,981	\$3,752	\$3,576

Table 33 - Oxidation Catalyst Cost Analysis for Turbines - BAT Emissions

Turbine HP (All dollar values in 2016 dollars)	1,000	1,590	3,000	5,000	6,130	7,500	11,150	15,900	17,500	20,000	25,000	30,000
Total Annual Costs	\$64,925	\$67,866	\$74,896	\$84,868	\$83,288	\$97,333	\$115,531	\$151,424	\$147,191	\$159,655	\$184,584	\$204,514
TPY of CO Emissions Reduced	4.26	3.77	7.05	9.84	11.90	13.32	18.31	10.74	10.90	12.29	15.08	17.43
TPY of NMNEHC Emissions Reduced	1.30	1.15	2.15	3.00	3.63	4.06	5.58	4.55	4.61	5.20	6.38	7.38
Cost Per Ton	\$11,670	\$13,810	\$8,142	\$6,612	\$5,363	\$5,600	\$4,836	\$9,903	\$9,486	\$9,123	\$8,599	\$8,243
TPY of CO Emissions Reduced, Alternative BAT				3.93	4.76	5.33	7.32					
TPY of NMNEHC Emissions Reduced, Alternative BAT				1.67	2.02	2.26	3.10					
Cost Per Ton				\$15,153	\$12,291	\$12,834	\$11,082					

As can be seen in Table 32 and Table 33 above, oxidation catalysts for turbines greater than or equal to 1,000 hp but less than 5,000 hp are not cost-effective; for turbines greater than or equal to 5,000 hp, oxidation catalysts are cost-effective based on a cost-effectiveness threshold of \$5,000 per ton of pollutant reduced. It is important to point out that for turbines less than 15,000 hp, the uncontrolled emissions and the BAT emissions are identical, with identical results.

For turbines greater than or equal to 15,900 hp, oxidation catalysts are cost-effective if one considers the uncontrolled emission rates of 25 ppm CO and 9 ppm NMNEHC as propane as a baseline. However, if one considers the alternative BAT emissions rate established in the previous GP-5 of 10 ppm CO and 5 ppm NMNEHC, oxidation catalysts are not cost-effective. Oxidation catalysts are also cost prohibitive for turbines rated greater than or equal to 5,000 hp but less than 15,900 hp with uncontrolled emissions rates of 10 ppm CO and 5 ppm NMNEHC, which is achievable according to stack test data. Therefore, it is the Department's determination that turbines greater than or equal to 5,000 hp but less than 15,900 hp have BAT criteria of 10 ppm CO and 5 ppm NMNEHC and that turbines greater than or equal to 15,900 hp have dual BAT criteria with BAT of 10 ppm CO uncontrolled and 1.75 ppm CO with control and 5 ppm NMNEHC.

XXV. Appendix D – Cost Analysis for Combustion Control Devices

Table 34 - Combustion Control Device Cost Analysis

(All dollar values in 2016 dollars)	Vendor A	Sensitivity Analysis			
Combustor	\$19,186				
Auto Ignitor	\$1,740				
Surveillance System	\$4,176				
Total Purchased Equipment Cost	\$25,102				
Freight and Design	\$1,740				
Installation	\$7,371				
Total Capital Investment	\$34,213	\$40,000	\$50,000	\$75,000	\$100,000
Pilot Fuel	\$2,201	\$2,573	\$3,216	\$4,824	\$6,432
Maintenance Cost	\$2,320	\$2,712	\$3,391	\$5,086	\$6,781
Data Management	\$1,160	\$1,356	\$1,695	\$2,543	\$3,391
Direct Annual Costs	\$5,681	\$6,641	\$8,302	\$12,453	\$16,603
Indirect Annual Costs	\$3,756	\$4,392	\$5,490	\$8,235	\$10,979
Total Annual Costs (7% Interest, 15 Year Life)	\$9,437	\$11,033	\$13,791	\$20,687	\$27,583
TPY of Methane	200.00	200.00	200.00	200.00	200.00
TPY of VOC	2.70	2.70	2.70	2.70	2.70
TPY of HAP	1.00	1.00	1.00	1.00	1.00
Cost Per Ton (95% Reduction)	\$49	\$57	\$71	\$107	\$143
Cost Per Ton (95% Reduction, Excluding Methane)	\$2,685	\$3,139	\$3,924	\$5,885	\$7,847
Cost Per Ton (98% Reduction)	\$47	\$55	\$69	\$104	\$138
Cost Per Ton (98% Reduction, Excluding Methane)	\$2,603	\$3,043	\$3,803	\$5,705	\$7,607

As can be seen from the table above, it is cost effective for a combustion control device that controls methane, VOC, and HAP based on the vendor quote and assuming an emission rate at the control threshold. In the sensitivity analysis, it is assumed that the annual costs scale relative to the increased total capital investment. If the cost-effectiveness threshold including methane is considered, it is cost-effective to install a combustion control device with a total capital investment of \$100,000 (and arguably much more) because it is much less than the \$1,000 per ton of pollutant reduced. If the cost-effectiveness threshold excluding methane is considered, combustion control devices are cost-effective up to a total capital investment of \$75,000 because it is close to the \$5,000 per ton of pollutant reduced.

Many commentators provided additional information on combustion control devices capabilities and cost, and so the Department conducted another cost analysis based on the new information. One aspect the Department explored was the effect of gas composition on the number of hours of operation an enclosed flare of the given characteristics would take to reach the proposed control thresholds. As seen in Table 35 below, the time varies for each pollutant, and establishes a range of operating hours. In Table 36 below, the emissions calculations were done based on the gas composition and the minimum and maximum operating hours calculated in Table 35.

Table 35 - Operating Hours to Reach Control Thresholds

Gas Composition Analysis	Original TSD Average Gas Composition	TSD Reanalysis Average Gas Composition	Rich Gas - Washington County Average	Dry Gas - Susquehanna County Average
Methane (vol%)			82.6%	97.4%
Methane (wt%)	88.8%	86.0%	67.3%	95.1%
VOC (vol%)			5.65%	0.08%
VOC (wt% as propane)	1.3%	4.5%	12.7%	0.2%
HAP (vol%)			0.0024%	0.0000%
HAP (wt% as hexane)	0.0500%	0.0000%	0.0105%	0.0000%
Total Weight of Gas (lb/cf gas)	0.0453	0.0442	0.0501	0.0418
Enclosed Flare Statistics				
Gas Throughput (lb/h)	4,800	4,800	4,800	4,800
Gas Throughput (Mcf/h)	106	109	96	115
Number of Pilots	3	3	3	3
Pilot Fuel Consumption (cf/h)	65	65	65	65
Annual Pilot Fuel Consumption (Mcf/yr)	1,708	1,708	1,708	1,708
Natural Gas Price (\$/Mcf)	\$2.50	\$2.50	\$2.50	\$2.50
Power Consumption (kWh/yr)	616	616	616	616
Electricity Price (\$/kWh)	\$0.07	\$0.07	\$0.07	\$0.07
Control Efficiency	95%	95%	95%	95%
Operational Assumptions				
Estimated Hours to Reach Control Threshold for Methane	94	97	124	88
Estimated Hours to Reach Control Threshold for VOC	90	25	9	524
Estimated Hours to Reach Control Threshold for Single HAP	417	-	1,983	-
Estimated Hours to Reach Control Threshold for Total HAP	833	-	3,967	-
Minimum Estimated Hours of Operation	90	25	9	88
Maximum Estimated Hours of Operation	833	97	3,967	524

Table 36 - Cost Sensitivity to Gas Composition and Hours of Operation

Gas Composition Analysis	Original TSD Average Gas Composition	TSD Reanalysis Average Gas Composition	Rich Gas - Washington County Average	Dry Gas - Susquehanna County Average
Maximum Emission Reductions				
Methane Reduced (tpy)	1,687	190	6,083	1,136
VOC Reduced (tpy)	23.75	9.87	1,144.39	2.57
Total HAP Reduced (tpy)	0.95	0.00	0.95	0.00
Minimum Emission Reductions				
Methane Reduced (tpy)	182	49	14	190
VOC Reduced (tpy)	2.57	2.57	2.57	0.43
Total HAP Reduced (tpy)	0.10	0.00	0.00	0.00
Emission Reductions from Control Thresholds				
Methane Reduced (tpy)	190	190	190	190
VOC Reduced (tpy)	2.57	2.57	2.57	2.57
Single HAP Reduced (tpy)	0.48	0.48	0.48	0.48
Total HAP Reduced (tpy)	0.95	0.95	0.95	0.95
Dollars Per Ton of Methane Reduced (\$/ton)	\$581	\$581	\$581	\$581
Dollars Per Ton of VOC Reduced (\$/ton)	\$43,047	\$43,047	\$43,047	\$43,047
Dollars Per Ton of Single HAP Reduced (\$/ton)	\$232,453	\$232,453	\$232,453	\$232,453
Dollars Per Ton of Total HAP Reduced (\$/ton)	\$116,226	\$116,226	\$116,226	\$116,226
Dollars Per Ton of All Pollutants Reduced Maximum (\$/ton)	\$65	\$552	\$15	\$97
Dollars Per Ton of All Pollutants Reduced Minimum (\$/ton)	\$598	\$2,126	\$6,816	\$580

The cost effectiveness for all pollutants at both the minimum and maximum hours of operation show that regardless of gas composition, an enclosed combustion device is economically feasible for the control of methane, VOC, and HAP.

Another commentator pointed out that control devices need to be sized for the worst-case scenario, which drives up the cost of the system based on the maximum gas flow to the control. The commentator provided operational data, summarized in Table 37 below, that gives both volume flow rates and mass flow rates as well as hours of operation.

Table 37 - Gas Flow Rates and Annual Hours of Operation

	Purge Gas	Closed Drain Vapors	Pigging Vapors (30" Receiver)	Pigging Vapors (12" C3+ Launcher)	Amine Unit Flash Gas	Total Maximum Flow Rate		Total Minimum Flow Rate	
						scfh	Mscfd	scfh	Mscfd
Volume Flow Rate (scfh)	434	26	120,000	48,135	2,154	170,749	4,098	2,588	62
Volume Flow Rate %	0.25%	0.02%	70.28%	28.19%	1.26%				
Mass Rate (lb/h)	18.68	1.43	6,723.53	6,885.81	177.91	13,807		197	
Annual Hours of Operation	8,760	2,190	12	1	8,760				

Another consideration is the effect of the previously calculated methane control threshold versus the newly calculated methane control threshold; as seen in Table 38 below, there is a significant increase in the cost per ton of methane reduced, as well as the cost per ton of all pollutants reduced. Cost-effectiveness on the basis of methane alone at 51.9 tpy is significantly beyond EPA's threshold of approximately \$1,000 per ton of methane reduced;

Table 38 - Cost-Effectiveness of Proposed vs. Recalculated Control Thresholds for Enclosed Combustion Devices

(All dollar values in 2016 dollars)	MSC Enclosed Oxidizer @ 250 Mscfd CH ₄	MSC Enclosed Oxidizer @ 250 Mscfd CH ₄	Vendor D Enclosed Flare @ 2,606 Mscfd	Vendor D Enclosed Flare @ 2,606 Mscfd	Vendor D Enclosed Flare @ 26,064 Mscfd	Vendor D Enclosed Flare @ 26,064 Mscfd
Total Annual Costs	\$68,059	\$68,059	\$110,415	\$110,415	\$445,745	\$445,745
TPY of CH₄ Emissions Reduced	190.00	49.31	190.00	49.31	190.00	49.31
Cost Per Ton	\$358	\$1,380	\$581	\$2,239	\$2,346	\$9,041
TPY of VOC Emissions Reduced	2.57	2.57	2.57	2.57	2.57	2.57
Cost Per Ton	\$26,534	\$26,534	\$43,047	\$43,047	\$173,780	\$173,780
TPY of HAP Emissions Reduced	0.95	0.95	0.95	0.95	0.95	0.95
Cost Per Ton	\$71,641	\$71,641	\$116,226	\$116,226	\$469,206	\$469,206
TPY of All Pollutants Emissions Reduced	193.52	52.82	193.52	52.82	193.52	52.82
Cost Per Ton	\$352	\$1,289	\$571	\$2,090	\$2,303	\$8,439

ranging from \$1,380 to \$9,041 per ton of methane reduced. However, considering all pollutants, an enclosed combustion device is still cost effective based on the cost-effectiveness threshold of \$5,000 per ton of pollutant reduced, ranging from \$1,289 to \$8,439 per ton of pollutant reduced. The Department must maintain, however, that the control threshold of 51.9 tpy is cost-prohibitive because for dry gas regions, methane is the likely trigger

for control, and as there are insignificant amounts of VOC and HAP in the gas stream, only the cost per ton of methane reduced should be considered for determining the cost-effectiveness. Performing a linear interpolation between the 51.2 tpy control threshold and the 200 tpy control threshold for the 2,606 Mscfd enclosed flare, the \$1,000 per ton of methane reduced threshold is approximately 163 tpy methane. This would provide a range from \$441 to \$2,886 per ton of methane reduced. However, the Department determines that BAT control measures for methane must be implemented for sources with emissions that meet or exceed 200 tpy methane; this requirement is also included in the exemption criteria for facilities seeking exemption under Category 38(c). One reason for conservatively establishing the methane control threshold at 200 tpy instead of 163 tpy is due to the inherent scientific uncertainty in the second analysis control threshold calculation discussed in Appendix A – Average Gas Composition Analysis and the site-specific uncertainty in the control costs from Appendix D – Cost Analysis for Combustion Control Devices.

For the primary BAT analysis, the Department determined the total annual flow through the enclosed flare based on the operational information from Table 37 and the average natural gas composition as determined in Table 16 of Appendix A – Average Gas Composition Analysis. Where the flow was given as a volume of methane, the Department used the methane density of 0.0416 lb/scf and the average gas composition density of 0.0442 lb/scf to determine the adjusted flow rate. For Vendor D, the flow was given in lb/h; the Department used the average gas composition density to determine the volume flow. The Department used EPA's Air Pollution Control Cost Manual to determine the total capital investment and total annual costs based on the purchased equipment prices provided by the commentators. The results can be seen in Table 39 below.

Table 39 - BAT Analysis for Enclosed Flare

(All dollar values in 2016 dollars)	MSC Enclosed Oxidizer @ 20 Mscfd CH ₄	MSC Enclosed Oxidizer @ 50 Mscfd CH ₄	MSC Enclosed Oxidizer @ 100 Mscfd CH ₄	MSC Enclosed Oxidizer @ 250 Mscfd CH ₄	MSC Enclosed Oxidizer @ 500 Mscfd CH ₄	MSC Enclosed Oxidizer @ 1,000 Mscfd CH ₄	Vendor D Enclosed Flare @ 2,606 Mscfd	MSC Enclosed Oxidizer @ 3,000 Mscfd CH ₄	MSC Enclosed Oxidizer @ 5,000 Mscfd CH ₄	Vendor D Enclosed Flare @ 26,064 Mscfd
Control Flow Rate (Mscfh)	0.88	2.21	4.43	11.07	22.13	44.27	108.60	132.81	221.35	1,085.97
Control Equipment Costs	\$50,500	\$90,900	\$111,100	\$146,450	\$212,100	\$373,700	\$300,000	\$479,750	\$757,500	\$1,500,000
Instrumentation	\$5,050	\$9,090	\$11,110	\$14,645	\$21,210	\$37,370	\$30,000	\$47,975	\$75,750	\$150,000
Freight	\$2,778	\$5,000	\$6,111	\$8,055	\$11,666	\$20,554	\$16,500	\$26,386	\$41,663	\$82,500
Total Purchased Equipment Costs	\$58,328	\$104,990	\$128,321	\$169,150	\$244,976	\$431,624	\$346,500	\$554,111	\$874,913	\$1,732,500
Total Direct Installation Costs	\$91,574	\$164,834	\$201,463	\$265,565	\$384,612	\$677,649	\$544,005	\$869,955	\$1,373,613	\$2,720,025
Total Indirect Installation Costs	\$20,415	\$36,746	\$44,912	\$59,202	\$85,741	\$151,068	\$121,275	\$193,939	\$306,219	\$606,375
Total Capital Investment	\$111,989	\$201,580	\$246,375	\$324,768	\$470,353	\$828,717	\$665,280	\$1,063,894	\$1,679,832	\$3,326,400
Operating and Supervisory Labor Costs	\$5,009	\$5,009	\$5,009	\$5,009	\$5,009	\$5,009	\$5,009	\$5,009	\$5,009	\$5,009
Maintenance Cost	\$9,583	\$9,583	\$9,583	\$9,583	\$9,583	\$9,583	\$9,583	\$9,583	\$9,583	\$9,583
Pilot Gas Cost	\$4,271	\$4,271	\$4,271	\$4,271	\$4,271	\$4,271	\$4,271	\$4,271	\$4,271	\$8,541
Annual Electricity Cost	\$43	\$43	\$43	\$43	\$43	\$43	\$43	\$43	\$43	\$86
Direct Annual Costs	\$18,906	\$18,906	\$18,906	\$18,906	\$18,906	\$18,906	\$18,906	\$18,906	\$18,906	\$23,219
Overhead	\$8,755	\$8,755	\$8,755	\$8,755	\$8,755	\$8,755	\$8,755	\$8,755	\$8,755	\$8,755
Administrative Charges	\$2,240	\$4,032	\$4,928	\$6,495	\$9,407	\$16,574	\$13,306	\$21,278	\$33,597	\$66,528
Insurance	\$1,120	\$2,016	\$2,464	\$3,248	\$4,704	\$8,287	\$6,653	\$10,639	\$16,798	\$33,264
Capital Recovery	\$10,571	\$19,027	\$23,255	\$30,655	\$44,397	\$78,223	\$62,796	\$100,421	\$158,559	\$313,979
Indirect Annual Costs	\$22,685	\$33,830	\$39,402	\$49,153	\$67,262	\$111,839	\$91,509	\$141,093	\$217,710	\$422,526
Total Annual Costs	\$41,591	\$52,735	\$58,307	\$68,059	\$86,168	\$130,745	\$110,415	\$159,999	\$236,615	\$445,745
Total Annual Gas Flow (TPY)	2.76	6.91	13.85	34.60	69.18	138.38	339.43	415.12	691.85	3,394.31
TPY of CH ₄ Emissions Reduced	2.25	5.65	11.32	28.28	56.54	113.10	277.41	339.27	565.44	2,774.12
Cost Per Ton	\$18,462	\$9,341	\$5,152	\$2,406	\$1,524	\$1,156	\$398	\$472	\$418	\$161
TPY of VOC Emissions Reduced	0.12	0.29	0.59	1.47	2.94	5.88	14.41	17.63	29.38	144.14
Cost Per Ton	\$355,329	\$179,782	\$99,151	\$46,315	\$29,334	\$22,249	\$7,660	\$9,076	\$8,054	\$3,092
TPY of HAP Emissions Reduced	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.03
Cost Per Ton	\$1,579,159,879	\$798,991,326	\$440,647,863	\$205,835,023	\$130,364,846	\$98,879,212	\$34,044,084	\$40,337,559	\$35,792,683	\$13,743,595
TPY of All Pollutants Emissions Reduced	2.37	5.94	11.91	29.75	59.47	118.98	291.83	356.90	594.83	2,918.29
Cost Per Ton	\$17,550	\$8,880	\$4,897	\$2,288	\$1,449	\$1,099	\$378	\$448	\$398	\$153

Table 40 – Cost-Effectiveness of Proposed vs. Recalculated Control Thresholds for Open Flares

(All dollar values in 2016 dollars)	Vendor D Open Flare @ 2,606 Mscfd	Vendor D Open Flare @ 2,606 Mscfd	Vendor D Open Flare @ 26,064 Mscfd	Vendor D Open Flare @ 26,064 Mscfd
Total Annual Costs	\$38,563	\$38,563	\$53,779	\$53,779
TPY of CH ₄ Emissions Reduced	190.00	49.31	190.00	49.31
Cost Per Ton	\$203	\$782	\$283	\$1,091
TPY of VOC Emissions Reduced	2.57	2.57	2.57	2.57
Cost Per Ton	\$15,034	\$15,034	\$20,966	\$20,966
TPY of HAP Emissions Reduced	0.95	0.95	0.95	0.95
Cost Per Ton	\$40,593	\$40,593	\$56,609	\$56,609
TPY of All Pollutants Emissions Reduced	193.52	52.82	193.52	52.82
Cost Per Ton	\$199	\$730	\$278	\$1,018

As can be seen in Table 40, open flares are less expensive and have lower annual operating costs than enclosed flares, ranging from \$203 to \$283 per ton of methane reduced for the 200 tpy methane control threshold. At the recalculated 51.9 tpy methane control threshold, the costs range from \$782 to \$1,091 per ton of methane reduced which just meets EPA’s Social Cost of Methane. However, the Department determines that BAT control measures for methane must be implemented for sources with emissions that meet or exceed 200 tpy methane; this requirement is also included in the exemption criteria for facilities seeking exemption under Category 38(c). One reason for conservatively establishing the methane control threshold at 200 tpy instead of 51.9 tpy is due to the inherent scientific uncertainty in the second analysis control threshold calculation discussed in Appendix A – Average Gas Composition Analysis and the site-specific uncertainty in the control costs from Appendix D – Cost Analysis for Combustion Control Devices.

For the primary BAT analysis, the Department determined the total annual flow through the open flare based on the operational information from Table 37 and the average natural gas composition as determined in Table 16 of Appendix A – Average Gas Composition Analysis. Where the flow was given as a volume of methane, the Department used the methane density of 0.0416 lb/scf and the average gas composition density of 0.0442 lb/scf to determine the adjusted flow rate. For Vendor D, the flow was given in lb/h; the Department used the average gas composition density to determine the volume flow. The Department used EPA’s Air Pollution Control Cost Manual to determine the total capital investment and total annual costs based on the purchased equipment prices provided by the commentators. The results can be seen in Table 41 below.

Open flares are only authorized to be used at remote facilities and with infrequent operations.

Table 41 - BAT Analysis for Open Flare

(All dollar values in 2016 dollars)	Vendor D Open Flare @ 2,606 Mscfd	Vendor D Open Flare @ 26,064 Mscfd
Control Flow Rate (Mscfh)	108.60	1,085.97
Control Equipment Costs	\$50,000	\$100,000
Instrumentation	\$5,000	\$10,000
Freight	\$2,750	\$5,500
Total Purchased Equipment Costs	\$57,750	\$115,500
Total Direct Installation Costs	\$90,668	\$181,335
Total Indirect Installation Costs	\$20,213	\$40,425
Total Capital Investment	\$110,880	\$221,760
Operating and Supervisory Labor Costs	\$5,009	\$5,009
Maintenance Cost	\$9,583	\$9,583
Pilot Gas Cost	\$1,424	\$2,847
Annual Electricity Cost	\$0	\$0
Direct Annual Costs	\$16,016	\$17,439
Overhead	\$8,755	\$8,755
Administrative Charges	\$2,218	\$4,435
Insurance	\$1,109	\$2,218
Capital Recovery	\$10,466	\$20,932
Indirect Annual Costs	\$22,548	\$36,340
Total Annual Costs	\$38,563	\$53,779
Total Annual Gas Flow (TPY)	339.43	3,394.31
TPY of CH ₄ Emissions Reduced	277.41	2,774.12
Cost Per Ton	\$139	\$19
TPY of VOC Emissions Reduced	14.41	144.14
Cost Per Ton	\$2,675	\$373
TPY of HAP Emissions Reduced	0.00	0.03
Cost Per Ton	\$11,890,087	\$1,658,157
TPY of All Pollutants Emissions Reduced	291.83	2,918.29
Cost Per Ton	\$132	\$18

XXVI. Appendix E – LDAR Cost Analysis

ICF has conducted two analyses on LDAR, one for the Environmental Defense Fund (EDF) in March of 2014²⁸ and one for ONE Future Inc. in May of 2016²⁹. In both analyses, they broke down the costs associated with an LDAR program into an hourly cost number. This was an adaptation of the analysis used by Colorado in their rulemaking. In the March 2014 analysis, the determination was that the total cost as an hourly rate was \$101.64 and that inspections would be performed on a quarterly basis. This resulted in an LDAR cost that ranged between \$2.15 and \$7.60 per Mcf of methane reduced, which approximates to between \$95 and \$336 per ton of methane reduced, when not counting the recovered gas value. In the May 2016 analysis, the determination was that the total cost as an hourly rate was \$142.06 and that inspections would be performed annually. This resulted in an LDAR cost that ranged between \$1.41 and \$6.94 per Mcf of methane reduced, which approximates to between \$62 and \$306 per ton of methane, when not counting the recovered gas value.

The Department conducted two independent LDAR cost analyses, the first using the ICF analyses as a basis and a second based on two vendors' quotes. The Department's assumptions in the first analysis included a semi-annual and quarterly survey interval for unconventional natural gas well sites and a quarterly survey interval for natural gas compression stations, processing plants, and transmission stations. The semi-annual frequency is assumed to result in a 50% emissions reduction and the quarterly frequency is assumed to result in a 60% emissions reduction. The Department favored the ONE Future Equipment Costs as the basis of the cost analysis as it includes a high-flow system for leak quantification in the analysis.

Table 42 and Table 43 below represent the Department's assumptions on frequency with the respective assumptions on emissions and hours for each survey from the two ICF analyses.

Table 42 - LDAR Costs with ONE Future Equipment Costs and EDF Assumptions

	Wellpads	Wellpads	Gathering	Processing	Transmission
Methane (Mcf/yr)	440	440	1,676	2,448	4,671
% Reduction	50%	60%	60%	60%	60%
Reduction (Mcf)	220	264	1,006	1,469	2,803
Hours each Inspection	2.7	2.7	8.0	8.0	8.0
Frequency per Year	2	4	4	4	4
Annual Inspection Cost	\$767	\$1,534	\$4,546	\$4,546	\$4,546
Initial Set-Up	\$77	\$153	\$455	\$455	\$455
Repair Labor Cost	\$575	\$1,151	\$3,409	\$3,409	\$3,409
Total Cost per Year	\$1,419	\$2,838	\$8,410	\$8,410	\$8,410
Cost of Reduction (\$/Mcf)	\$6.45	\$10.75	\$8.36	\$5.73	\$3.00
Cost of Reduction (\$/ton)	\$309.39	\$515.65	\$401.11	\$274.62	\$143.92

²⁸ Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries, ICF International on behalf of the Environmental Defense Fund, March 2014.

²⁹ Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems, ICF International on behalf of ONE Future Inc., May 2016.

Table 43 - LDAR Costs with ONE Future Equipment Costs and Assumptions

	Wellpads	Wellpads	Gathering	Processing	Transmission
Methane (Mcf/yr)	3,057	3,057	3,605	5,986	3,605
% Reduction	50%	60%	60%	60%	60%
Reduction (Mcf)	1,529	1,834	2,163	3,592	2,163
Hours each Inspection	5.5	5.5	32.0	40.0	32.0
Frequency per Year	2	4	4	4	4
Annual Inspection Cost	\$1,563	\$3,125	\$18,184	\$22,730	\$18,184
Initial Set-Up	\$156	\$313	\$1,818	\$2,273	\$1,818
Repair Labor Cost	\$1,172	\$2,344	\$13,638	\$17,047	\$13,638
Total Cost per Year	\$2,891	\$5,782	\$33,640	\$42,050	\$33,640
Cost of Reduction (\$/Mcf)	\$1.89	\$3.15	\$15.55	\$11.71	\$15.55
Cost of Reduction (\$/ton)	\$90.71	\$151.19	\$745.92	\$561.53	\$745.92

As can be seen in the tables, the cost of reduction in both cases is well within the cost-effective range of \$1,000 per ton of methane reduced.

A. The Department's Independent LDAR Cost Analysis

Since the number of leaking components, amount of leakage from individual components, duration, and frequency is uncertain at an individual facility, it is impractical to perform a generic cost-analysis for LDAR requirements for static and rotating components (flanges, valves, joints, packing of compressor rods, etc.) at well sites, natural gas compression, processing or transmission facilities.

However, the Department contacted representatives of two companies that offer services for LDAR for the sources at well sites, and natural gas compression, processing or transmission facilities, to determine the estimated costs for leak detection, quantification, and repair tasks. Neither company offered quotes for repair costs since the costs for repairs vary significantly, depending on which components are leaking and what type of maintenance is required to repair the leaks. Therefore, the analysis is based only on the quoted costs for methane gas leak detections and quantifications.

According to the representative of the first company, a dry natural gas well pad contains approximately 1,000 components. Wet gas well pads, and compression, processing, or transmission facilities contain approximately 2,000 components. Typically, it takes one person and one day (10 hours) to complete the leak detection task using an OGI camera for a dry gas well pad. It takes one person two days to complete the leak detection using an OGI camera for a wet gas well pad, or natural gas compression, processing, or transmission station. The company charges \$75 per hour for manpower, \$400 per day for travel costs, \$150 per day for camera rental, and \$300 per day for gas leak detection device rental.

The company charges the same amount for labor for leak quantification, and assuming all components are leaking it takes two people three days to quantify leaks from all 1,000 components at a dry gas well pad, and two people six days to quantify leaks from all 2,000 components at a wet gas well pad, or natural gas compression, processing, or transmission facility. This yields a labor rate of 0.06 man-hours per component that is leaking, and in the analysis the Department will round up to the nearest full day.

The Department also contacted representatives of the second company to determine their costs for LDAR services, and they echoed the cost that was suggested by the first company. According to the company representatives, typically it costs \$750 - \$1,500 for any well pad or natural gas compression station for leak detection and quantification.

Based on the above information, the Department performed cost-effectiveness analysis for leak detection and quantification requirements stated for sources located at well pads, and natural gas compression, processing, or transmission facilities. The costs for leak detection were assumed to be at the full quoted cost and the costs for leak quantification were based on the amount of time to survey 1%, 2%, and 3% of the components rounded up to the nearest full day for sources at dry gas well pads, wet gas well pads, and natural gas compression, processing, and transmission facilities.

According to Method 21, the detector must have a sampling rate between 3.53×10^{-3} and 0.11 cf/min. At the maximum sampling rate, a 500 ppm indication on a Method 21 detector would be approximately equivalent to a 0.08 cf/day emission rate for a component if it is assumed that 100% of the leak is captured. For leaks above 500 ppm, it is less likely that 100% of the leak is captured, but for purposes of this analysis, it is assumed the detector does capture all of the emissions up to the 100,000 ppm level for a calculated leak rate of 15.84 cf/day. For any leak above 100,000 ppm on a Method 21 device, a high-flow sampler must be used for quantification. A high-flow device has a sampling rate of 10 cf/min and can detect leaks between 0.05 cf/min and 8.00 cf/min. This results in leak emission rates of 72.00 cf/day and 11,520 cf/day, respectively.

Based on the several leak studies, one vendor informed the Department that the majority of leak emissions come from a small percentage of “super-emitters.” The Department assumes the “super-emitters” emit at the 11,520.00 cf/day rate and the total daily emission rate is based on the equation:

$$E = \frac{(P_{SE})(C_l) \left(11,520 \frac{cf}{day} \right)}{(P_E)}$$

Where:

E = Total Daily Emission Rate

P_{SE} = Percentage of “Super-Emitters”

C_l = Number of Leaking Components

P_E = Percentage of Total Emissions Attributed to “Super-Emitters”

The following table outlines the calculated total daily emission rate for 1% of the total components at a dry gas well site found leaking.

Table 44 - Super-Emitter Study Data and LDAR Costs³⁰

Study Author	Percent	Percent of Total Emissions	Calculated Total Daily Emission Rate	Annual Emissions	Annual Avoided Emissions	Cost per Ton of Methane Reduced
	“Super-Emitters”	(P _E)	(E)	(Mcf/y)	(TPY)	(\$/ton)
	(P _{SE})		(cf/day)			
Brandt, et. al.	5.00%	50%	11,520.00	4,204.80	52.6	\$228.13
Rella, et. al.	6.60%	50%	15,206.40	5,550.30	69.4	\$172.82
	22%	80%	9,642.60	3,519.50	44	\$272.54
Clearstone Engineering	0.06%	58%	119.2	43.5	0.5	\$22,047.27
British Columbia Oil & Gas	6.00%	80%	8,640.00	3,153.60	39.5	\$304.17

The ONE Future emissions estimate from well sites is 3,057 Mcf/y, and the EDF emission estimate from well sites is 440 Mcf/y. Assuming the Department’s costs and that the emissions estimates are from 1% of the total components, this results in costs of \$313.78 per ton of methane reduced and \$2,180.07 per ton of methane reduced, respectively. The British Columbia Oil & Gas and the Rella, *et al.* top 22% of leaks responsible for 80% of total emissions estimates are in line with ONE Future’s emissions estimates from well sites.

Brandt, *et al.* and the Rella, *et al.* top 6.6% responsible for 50% of total emissions estimates are nearly 80% higher than ONE Future’s emissions estimates. This serves to drive down the cost per ton of methane reduced. The Clearstone Engineering emissions estimate is approximately 1.5% of the ONE Future emission estimate, which serves to significantly drive up the cost per ton of methane reduced. The Department therefore focused on the British Columbia and Rella, *et al.* 22% cases in the cost analysis.

Based on our independent analysis, the Department determines that quarterly LDAR is technically and economically feasible for the control of methane emissions. The Department preserves the off-ramp originally proposed if less than 2% of components are found to be leaking in two consecutive inspections to help small businesses that operate effectively to reduce the frequency of inspections, and thereby reduce costs.

³⁰ The second line under Rella, et. al. is calculated assuming that 6.6% emit at the 11,520 cf/day rate and the remaining 15.4% emit at the 72.0 cf/day rate.

Table 45 - LDAR Costs from Vendor Quotes

TOTAL ANNUAL COST FOR LEAK DETECTION											
Facility	~No. of Components		Leak Detection Duration (Days)	Labor Cost Per Man-Hour	Number of Hours/Day	Manpower	Travel Cost (\$400/Day-Man)	Equipment Rental (OGI) (\$150/Day-Man)	Contingency (\$200/Day-Man)	Frequency per Year	Annual Cost for Leak Detection
Wellpad (Dry Gas)	1,000		1	\$75	10	1	\$400	\$150	\$200	4	\$6,000
Wellpad (Wet Gas), Compressor Station, Processing Plant, or Transmission Station	2,000		2	\$75	10	1	\$800	\$300	\$400	4	\$12,000
TOTAL ANNUAL COST FOR LEAK QUANTIFICATION											
Facility	Percent Leaking Components	~No. of Components Leaking	Leak Quantification Duration (Days)	Labor Cost Per Man-Hour	Number of Hours/Day	Manpower	Travel Cost (\$400/Day-Man)	Equipment Rental (Method 21) (\$150/Day-Man)	Contingency (\$200/Day-Man)	Frequency per Year	Annual Cost for Leak Quantification
Wellpad (Dry Gas)	1.0%	10	1	\$75	10	1	\$400	\$150	\$200	4	\$6,000
	2.0%	20	1	\$75	10	1	\$400	\$150	\$200	4	\$6,000
	3.0%	30	1	\$75	10	1	\$400	\$150	\$200	4	\$6,000
Wellpad (Wet Gas), Compressor Station, Processing Plant, or Transmission Station	1.0%	20	1	\$75	10	1	\$400	\$150	\$200	4	\$6,000
	2.0%	40	1	\$75	10	1	\$400	\$150	\$200	4	\$6,000
	3.0%	60	1	\$75	10	1	\$400	\$150	\$200	4	\$6,000

Table 46 - LDAR Cost Analysis Based on Rella *et al.* and British Columbia Emissions Assumptions

TOTAL ANNUAL COST FOR LEAK DETECTION AND LEAK QUANTIFICATION												
Facility	Percent Leaking Components	Total Annual Cost	Rella et. al.					British Columbia Oil and Gas				
			Total Flow Rate (CF/Day)	Undetected Annual PTE (CFY)	Avoided Emissions (CFY)	Mass of Avoided Emissions (TPY)	\$/ton	Total Flow Rate (CF/Day)	Undetected Annual PTE (CFY)	Avoided Emissions (CFY)	Mass of Avoided Emissions (TPY)	\$/ton
Wellpad (Dry Gas)	1.0%	\$12,000	9,643	3,519,549	2,111,729	44.03	\$272.54	8,640	3,153,600	1,892,160	39.45	\$304.17
	2.0%	\$12,000	19,285	7,039,098	4,223,459	88.06	\$136.27	17,280	6,307,200	3,784,320	78.90	\$152.09
	3.0%	\$12,000	28,928	10,558,647	6,335,188	132.09	\$90.85	25,920	9,460,800	5,676,480	118.35	\$101.39
Wellpad (Wet Gas), Compressor Station, Processing Plant, or Transmission Station	1.0%	\$18,000	19,285	7,039,098	4,223,459	88.06	\$204.41	17,280	6,307,200	3,784,320	78.90	\$228.13
	2.0%	\$18,000	38,570	14,078,196	8,446,918	176.12	\$102.20	34,560	12,614,400	7,568,640	157.81	\$114.06
	3.0%	\$18,000	57,856	21,117,294	12,670,376	264.18	\$68.14	51,840	18,921,600	11,352,960	236.71	\$76.04

B. The Department’s Revised LDAR Cost Analysis

Based on comments received, the Department has performed a brief reanalysis of LDAR costs, which are summarized in Table 47 below. Even with a leak rate at 0.13% of production or throughput, the mass and volume of emissions are very high. The corresponding costs, which are based on the Annual Costs for Leak Detection in Table 45, the assumed leak rate, and the assumed production and throughput rates yield cost effectiveness numbers well below EPA’s Social Cost of Methane. Based on our revised analysis, the Department determines that quarterly LDAR is technically and economically feasible for the control of methane emissions. The Department preserves the off-ramp originally proposed if less than 2% of components are found to be leaking in two consecutive inspections to help small businesses that operate effectively to reduce the frequency of inspections, and thereby reduce costs.

Table 47 - Revised LDAR Cost Analysis

TOTAL ANNUAL COST FOR LEAK DETECTION ¹						
Facility	Total Annual Cost	Total Flow Rate (CF/Day)	Undetected Annual PTE (CFY)	Avoided Emissions (CFY)	Mass of Avoided Emissions (TPY)	\$/ton
Wellpad (Dry Gas) ²	\$6,000	13,000	4,745,000	2,847,000	59.36	\$101.08
Wellpad (Wet Gas) ²	\$12,000	13,000	4,745,000	2,847,000	59.36	\$202.16
Compressor Station, Processing Plant, or Transmission Station ³	\$12,000	910,000	332,150,000	199,290,000	4,155.20	\$2.89

¹ The Annual Cost reflects only leak detection, as the leak quantification requirements were removed.

² The assumed production was 10 MMcf/d, with an assumed leak rate of 0.13% of production.

³ The assumed throughput was 700 MMcf/d based on the previously referenced U.S. EIA report (see page 26), with an assumed leak rate of 0.13% of throughput.

XXVII. Appendix F – Urbanized Areas and Urban Clusters from the 2010 Census

Albion, PA Urban Cluster (2010)
Allentown, PA--NJ Urbanized Area (2010)
Altoona, PA Urbanized Area (2010)
Ashland, PA Urban Cluster (2010)
Bedford, PA Urban Cluster (2010)
Belleville, PA Urban Cluster (2010)
Belvidere, NJ--PA Urban Cluster (2010)
Binghamton, NY--PA Urbanized Area (2010)
Blairsville, PA Urban Cluster (2010)
Bloomsburg--Berwick, PA Urbanized Area (2010)
Bonneauville, PA Urban Cluster (2010)
Bradford, PA--NY Urban Cluster (2010)
Brockway, PA Urban Cluster (2010)
Brookville, PA Urban Cluster (2010)
Burgettstown, PA Urban Cluster (2010)
Butler, PA Urban Cluster (2010)
Cambridge Springs, PA Urban Cluster (2010)
Chambersburg, PA Urbanized Area (2010)
Clarion, PA Urban Cluster (2010)
Cresson, PA Urban Cluster (2010)
Cumberland, MD--WV--PA Urbanized Area (2010)
East Liverpool, OH--WV--PA Urban Cluster (2010)
East Prospect, PA Urban Cluster (2010)
East Stroudsburg, PA--NJ Urbanized Area (2010)
Edinboro, PA Urban Cluster (2010)
Ellwood City, PA Urban Cluster (2010)
Emmitsburg, MD--PA Urban Cluster (2010)
Emporium, PA Urban Cluster (2010)
Erie, PA Urbanized Area (2010)
Everett, PA Urban Cluster (2010)
Fairdale, PA Urban Cluster (2010)
Franklin (Venango County), PA Urban Cluster (2010)
Greenville, PA Urban Cluster (2010)
Grove City, PA Urban Cluster (2010)

Hagerstown, MD--WV--PA Urbanized Area (2010)
Hanover, PA Urbanized Area (2010)
Harrisburg, PA Urbanized Area (2010)
Hazleton, PA Urbanized Area (2010)
Honesdale, PA Urban Cluster (2010)
Houtzdale, PA Urban Cluster (2010)
Huntingdon, PA Urban Cluster (2010)
Jersey Shore, PA Urban Cluster (2010)
Jim Thorpe, PA Urban Cluster (2010)
Johnstown, PA Urbanized Area (2010)
Kutztown, PA Urban Cluster (2010)
Lake Meade, PA Urban Cluster (2010)
Lancaster, PA Urbanized Area (2010)
Lebanon, PA Urbanized Area (2010)
Lewistown, PA Urban Cluster (2010)
Ligonier, PA Urban Cluster (2010)
Littlestown, PA Urban Cluster (2010)
Lock Haven, PA Urban Cluster (2010)
Lykens, PA Urban Cluster (2010)
Mansfield, PA Urban Cluster (2010)
Martinsburg, PA Urban Cluster (2010)
Masontown, PA Urban Cluster (2010)
Meadville, PA Urban Cluster (2010)
Mercer, PA Urban Cluster (2010)
Meyersdale, PA Urban Cluster (2010)
Mifflinburg, PA Urban Cluster (2010)
Mifflintown, PA Urban Cluster (2010)
Milford, NJ--PA Urban Cluster (2010)
Millersburg, PA Urban Cluster (2010)
Millsboro, PA Urban Cluster (2010)
Milton--Lewisburg, PA Urban Cluster (2010)
Monessen--California, PA Urbanized Area (2010)
Montgomery, PA Urban Cluster (2010)
Moscow, PA Urban Cluster (2010)

Mount Holly Springs, PA Urban Cluster (2010)
Mount Union, PA Urban Cluster (2010)
Muncy, PA Urban Cluster (2010)
Nanty-Glo, PA Urban Cluster (2010)
New Castle, PA Urban Cluster (2010)
New Freedom--Shrewsbury, PA--MD Urban Cluster (2010)
New Wilmington, PA Urban Cluster (2010)
North East, PA Urban Cluster (2010)
Northern Cambria, PA Urban Cluster (2010)
Oil City, PA Urban Cluster (2010)
Orwigsburg, PA Urban Cluster (2010)
Philadelphia, PA--NJ--DE--MD Urbanized Area (2010)
Philipsburg, PA Urban Cluster (2010)
Pine Grove, PA Urban Cluster (2010)
Pittsburgh, PA Urbanized Area (2010)
Portage, PA Urban Cluster (2010)
Pottstown, PA Urbanized Area (2010)
Pottsville, PA Urban Cluster (2010)
Punxsutawney, PA Urban Cluster (2010)
Quarryville, PA Urban Cluster (2010)
Reading, PA Urbanized Area (2010)
Reynoldsville, PA Urban Cluster (2010)
Ridgway, PA Urban Cluster (2010)
Roaring Spring, PA Urban Cluster (2010)
Saw Creek, PA Urban Cluster (2010)
Sayre--Waverly, PA--NY Urban Cluster (2010)
Scranton, PA Urbanized Area (2010)
Shamokin--Mount Carmel, PA Urban Cluster (2010)
Shippensburg, PA Urban Cluster (2010)
Sierra View--Indian Mountain Lake, PA Urban Cluster (2010)
Slippery Rock, PA Urban Cluster (2010)
Somerset, PA Urban Cluster (2010)
State College, PA Urbanized Area (2010)
Stewartstown, PA Urban Cluster (2010)
Susquehanna Depot, PA Urban Cluster (2010)
Titusville, PA Urban Cluster (2010)

Towanda, PA Urban Cluster (2010)
Treasure Lake, PA Urban Cluster (2010)
Tunkhannock, PA Urban Cluster (2010)
Tyrone, PA Urban Cluster (2010)
Union City, PA Urban Cluster (2010)
Uniontown--Connellsville, PA Urbanized Area (2010)
Waynesboro, PA--MD Urban Cluster (2010)
Waynesburg, PA Urban Cluster (2010)
Weirton--Steubenville, WV--OH--PA Urbanized Area (2010)
Williamsport, PA Urbanized Area (2010)
Williamstown, PA Urban Cluster (2010)
Youngstown, OH--PA Urbanized Area (2010)
Youngsville, PA Urban Cluster (2010)

XXVIII. Appendix G – Non-road Engine Standards

The emission limits in the following tables are expressed in g/bhp-h.

Table 48 - Non-Road Compression Ignition Engine Emission Standards

	Tier 1					Tier 2					Tier 3					Tier 4i					Tier 4f				
	Model Year	NO _x	HC	CO	PM	Model Year	NO _x	HC	CO	PM	Model Year	NO _x	HC	CO	PM	Model Year	NO _x	HC	CO	PM	Model Year	NO _x	HC	CO	PM
HP < 11	2000	7.83		5.97	0.75	2005	5.59		5.97	0.6						2008	5.59		5.97	0.3	2014	5.59		5.97	0.3
11 ≤ HP < 25	2000	7.08		4.92	0.75	2005	5.59		4.92	0.6						2008	5.59		4.92	0.3	2014	5.59		4.92	0.3
25 ≤ HP < 50	1999	7.08		4.1	0.75	2004	5.59		4.1	0.45						2008	5.59		4.1	0.22	2014	3.5		4.1	0.02
																2013	3.5		3.73	0.02					
50 ≤ HP < 75	1998	6.86				2004	5.59	3.73	0.3	2008	3.5	3.73	0.3	2013	3.5		3.73	0.02	2014	3.5		3.73	0.01		
75 ≤ HP < 100														2014	0.3	0.14	3.73	0.01	2014	0.3	0.14	3.73	0.01		
100 ≤ HP < 175	1997	6.86				2003	4.92	3.73	0.22	2007	2.98	3.73	0.22	2014	0.3	0.14	3.73	0.01							
175 ≤ HP < 300	1996	6.86	0.97	8.5	0.4	2003	4.92	2.61	0.15	2006	2.98	2.61	0.15	2014	0.3	0.14	2.61	0.01	2014	0.3	0.14	2.61	0.01		
300 ≤ HP < 600	1996	6.86	0.97	8.5	0.4	2001	4.77	2.61	0.15	2006	2.98	2.61	0.15												
600 ≤ HP ≤ 750	1996	6.86	0.97	8.5	0.4	2002	4.77	2.61	0.15	2006	2.98	2.61	0.15												
750 < HP ≤ 1205	2000 6.86 0.97 8.5 0.54					2006	4.77	2.61	0.15						2014	2.61	0.3	2.61	0.07	2014 Gen Set	0.5	0.14	2.61	0.02	
1205 < HP															2014 Gen Set	0.5	0.3	2.61	0.07	2014 Other	2.61	0.14	2.61	0.03	
															2014 Other	2.61	0.3	2.61	0.07						

Table 49 - Non-Road Spark Ignition Engine Emission Standards

		General Emission Standards		Severe-Duty Engine Emission Standards	
		NO _x + HC	CO	NO _x + HC	CO
Certification and Production-Line Testing	Tier 1	2.98	37.29	2.98	96.94
Field Testing	Model Year 2004-2006	4.03	37.92	4.03	96.94
Steady-State Testing	Tier 2 Model Year 2007-	2.01	3.28	2.01	96.94
Transient Testing		2.01	3.28		
Field Testing		2.83	4.85	2.83	149.14

XXIX. Appendix H – Well Site Rod Packing Replacement Cost-Effectiveness Analysis

Table 50 - Rod Packing Cost Analysis with Revised Emission Factors

(All dollar values in 2016 dollars)	EPA TSD Production	UT Methane Emission Factor Production - low	UT Methane Emission Factor Production - high	UT Methane Emission Factor Production - measured	UT Methane Emission Factor Production - average
Packing Replacement Costs (Materials and Installation)	\$1,814	\$1,814	\$1,814	\$1,814	\$1,814
Annualized Packing Replacement Cost	\$698	\$698	\$698	\$698	\$698
Total Annualized Costs	\$698	\$698	\$698	\$698	\$698
TPY of CH₄ Emissions Reduced	0.0456	0.0456	5.6104	0.9144	2.1901
TPY of VOC Emissions Reduced	0.0024	0.0024	0.2915	0.0475	0.1138
TPY of HAP Emissions Reduced	0.0000	0.0000	0.0001	0.0000	0.0000
Cost Per Ton Pollutant	\$14,551	\$14,551	\$118	\$726	\$303
Cost Per Ton Methane	\$15,307	\$15,307	\$124	\$763	\$319
Cost Per Ton VOC	\$294,603	\$294,603	\$2,395	\$14,692	\$6,134
Cost Per Ton HAP	\$1,316,877,281	\$1,316,877,281	\$10,703,529	\$65,671,548	\$27,418,845

XXX. Appendix I – GP-5 Malfunction Reporting Instructions

GP-5 Malfunction Reporting Instructions

1. Malfunction reporting to the PA Department of Environmental Protection (DEP or Department) under GP-5 must be conducted as follows:

- a. The owner/operator authorized to use GP-5 shall report to DEP each malfunction that results in a potential exceedance of the GP-5 emissions limits. For GP-5 purposes, the term malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control or process equipment, or, operating in a non-permitted manner, which results in, or may possibly be resulting in, the emission of air contaminants in excess of any applicable limitations specified in GP-5.
- b. The notification, recordkeeping and reporting requirements relating to performance testing, work practice and monitoring standards, equipment leaks or fugitive emissions noted in GP-5 are not subject to the malfunction reporting requirements.
- c. When the malfunction or incident poses an imminent and substantial danger to the public health and safety, and/or potential harm to the environment, the owner/operator shall report the incident to the Department and the County Emergency Management Agency immediately after the discovery of an incident. The owner/ operator shall submit a written report of instances of such malfunctions or incidents to the Department within three (3) business days of the telephone report.
 - i. The Report shall include the following:
 - a) name and location of the facility;
 - b) nature and cause of the malfunction or incident;
 - c) time when the malfunction, incident or breakdown was first observed;
 - d) expected duration of increased emissions; and
 - e) estimated rate of emissions
 - ii. The Owner/Operator shall notify the Department immediately when corrective measures have been accomplished.
- d. Incidents covered by the notification, recordkeeping and reporting requirements relating to performance testing, work practice and monitoring standards, equipment leaks or fugitive emissions noted in this general permit are not subject to the reporting requirements of this section.
- e. Any malfunction or incident that is not subject to the notice requirements of paragraph (c) of this document shall be reported to the Department by telephone within 24 hours (or by 4:00 PM of the next business day, whichever is later) of discovery and in writing or e-mail within five days of discovery of the incident. The report shall contain the same information required by paragraph (c)(i).
- f. The Department may require, when a malfunction or other incident results in citizen complaints, the Owner/Operator to report the incident immediately to the Department. The Department will review the incident and determine if a written follow up report including corrective action is needed.
- g. Malfunctions shall be reported to the appropriate DEP Regional Office Air Program Manager.

2. Examples of Malfunctions or Incidents are provided below.

- a. Malfunctions or incidents posing an imminent and substantial danger to the public health and safety.
 - i. Reportable
 - a) Fire;
 - b) Explosion; or
 - c) Explosive or other condition that may impact outside of the fence-line or require evacuations.
- b. Malfunctions or incidents that do not pose an imminent and substantial danger to public health and safety but may result in an exceedance of GP-5 emissions limits.
 - i. Reportable Malfunctions or Incidents
 - a) Process equipment incidents, or air pollution control equipment shutdown or reduction in control which results in VOC, NOX, CO, HAP, or Formaldehyde emissions in excess of the General Permit's emissions limits or permit requirements.
 - b) Equipment or operation failure, or malfunctions in process or pollution control equipment that result in fugitive particulate emission or odor beyond the facility boundary.
 - ii. Non-reportable Malfunctions or Incidents
 - a) Air Pollution Control equipment shutdowns that are rectified by automatic restarts, other adjustments of the operation as per the manufacturer.
 - b) Air Pollution Control equipment shutdowns which are manually restarted within one hour of the malfunction and do not result in emissions in excess of GP limitations.
 - c) Malfunctions in process or pollution control equipment which result in odor or fugitive dust emissions which are contained within the facility's fence-line.
 - d) Building fire eyes or gas detector trips that pose no harm to the public.
 - e) False fire eyes or other safety device trips which do not pose harm to the public.
 - f) Upset conditions within the site boundaries which do not pose a threat to the public provided that they do not result in a potential exceedance of the GP-5 emissions limits.
- c. Emergency Releases
 - i. Reportable Releases
 - a) Unplanned Emergency Shut-down events that result in a potential exceedance of permit emission limits or create an offsite risk.
 - b) Relief valves that stay open, or frequently relieve and may result in a potential exceedance of permit limits.
 - ii. Non- Reportable Releases
 - a) Vents from pressure safety relief valves (PSVs) that do not result in a potential exceedance of permit limits or create an offsite risk. However, DEP should be notified by telephone if there is noise from the release that results in community complaints to the facility owner/operator, or there are multiple PSV incidents.
- d. Planned Compressor Vents, Engine Starters and Other Emissions Included in the Application
 - i. Non-Reportable Releases
 - a) Venting from compressors as described in the GP-5 Application that do not result in an exceedance of emission limits.

- b) Gas from engine starters as described in the application that do not result in an exceedance of emission limits. Planned or required ESDs included in the application that do not result in an exceedance of emission limits.
 - c) Rod packing or crankcase vent emissions – source of minor significance normally detailed in the permit application.
- e. Malfunctions or Other Incidents That Result in Citizen Complaints – Courtesy Reporting
 - i. Incident Reporting
 - a) Noise from pressure relief valves or other safety devices that result in community complaints to the facility owner/operator.
 - b) Odors from an off-site source when detected in the area.
 - c) Issues that have received prior community complaints.
 - d) Emergency Response Drills held at the facility where a number of emergency vehicles may be present.
 - f. Dehydrators
 - i. Reportable Incidents
 - a) Still vent bypass or flash tank venting from freezing or process malfunction that has the potential to exceed permit emission limitations.
 - b) Malfunctions of process controls that may or may not result in exceedances of permit limits.
 - ii. Non-Reportable Incidents
 - a) Still vent or flash tank bypass of oxidizers or other controls during automated restart sequence, without any potential to exceed permit emission limits.

NOTE: Emissions (including emissions from malfunctions) from all sources must be included in the source reports submitted to DEP by March 1st each year as prescribed in 25 Pa. Code Chapter 135 (relating to reporting of sources).

Alternative Control Techniques Document— NO_x Emissions from Stationary Gas Turbines

Emission Standards Division

**U. S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711
January 1993**

ALTERNATIVE CONTROL TECHNIQUES DOCUMENTS

This report is issued by the Emission Standards Division, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, to provide information to State and local air pollution control agencies. Mention of trade names and commercial products is not intended to constitute endorsement or recommendation for use. Copies of this report are available—as supplies permit—from the Library Services Office (MD-35), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711 ([919] 541-2777) or, for a nominal fee, from the National Technical Information Services, 5285 Port Royal Road, Springfield, Virginia 22161 ([800] 553-NTIS).

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1.0 INTRODUCTION

Congress, in the Clean Air Act Amendments of 1990 (CAAA), amended Title I of the Clean Air Act (CAA) to address ozone nonattainment areas. A new Subpart 2 was added to Part D of Section 103. Section 183(c) of the new Subpart 2 provides that:

[w]ithin 3 years after the date of the enactment of the CAAA, the Administrator shall issue technical documents which identify alternative controls for all categories of stationary sources of...oxides of nitrogen which emit or have the potential to emit 25 tons per year or more of such air pollutant.

These documents are to be subsequently revised and updated as determined by the Administrator.

Stationary gas turbines have been identified as a category that emits more than 25 tons of nitrogen oxide (NO_x) per year. This alternative control techniques (ACT) document provides technical information for use by State and local agencies to develop and implement regulatory programs to control NO_x emissions from stationary gas turbines. Additional ACT documents are being developed for other stationary source categories.

Gas turbines are available with power outputs ranging from 1 megawatt (MW) (1,340 horsepower [hp]) to over 200 MW (268,000 hp) and are used in a broad scope of applications. It must be recognized that the alternative control techniques and the corresponding achievable NO_x emission levels presented in this document may not be applicable for every gas turbine application. The size and design of the turbine, the operating duty cycle, site conditions, and other site-specific factors must be taken into consideration, and the suitability of an

alternative control technique must be determined on a case-by-case basis.

The information in this ACT document was generated through a literature search and from information provided by gas turbine manufacturers, control equipment vendors, gas turbine users, and regulatory agencies. Chapter 2.0 presents a summary of the findings of this study. Chapter 3.0 presents information on gas turbine operation and industry applications. Chapter 4.0 contains a discussion of NO_x formation and uncontrolled NO_x emission factors. Alternative control techniques and achievable controlled emission levels are included in Chapter 5.0. The cost and cost effectiveness of each control technique are presented in Chapter 6.0. Chapter 7.0 describes environmental and energy impacts associated with implementing the NO_x control techniques.

2.0 SUMMARY

This chapter summarizes the more detailed information presented in subsequent chapters of this document. It presents a summary of nitrogen oxide (NO_x) formation mechanisms and uncontrolled NO_x emission factors, available NO_x emission control techniques, achievable controlled NO_x emission levels, the costs and cost effectiveness for these NO_x control techniques applied to combustion gas turbines, and the energy and environmental impacts of these control techniques. The control techniques included in this analysis are water or steam injection, dry low- NO_x combustors, and selective catalytic reduction (SCR).

Section 2.1 includes a brief discussion of NO_x formation and a summary of uncontrolled NO_x emission factors. Section 2.2 describes the available control techniques and achievable controlled NO_x emission levels. A summary of the costs and cost-effectiveness for each control technique is presented in Section 2.3. Section 2.4 reviews the range of controlled emission levels, capital costs, and cost effectiveness. Section 2.5 discusses energy and environmental impacts.

2.1 NO_x FORMATION AND UNCONTROLLED NO_x EMISSIONS

The two primary NO_x formation mechanisms in gas turbines are thermal and fuel NO_x . In each case, nitrogen and oxygen present in the combustion process combine to form NO_x . Thermal NO_x is formed by the dissociation of atmospheric nitrogen (N_2) and oxygen (O_2) in the turbine combustor and the subsequent formation of NO_x . When fuels containing nitrogen are combusted, this additional source of nitrogen results in fuel NO_x formation. Because most turbine installations burn natural gas or light

distillate oil fuels with little or no nitrogen content, thermal NO_x is the dominant source of NO_x emissions. The formation rate of thermal NO_x increases exponentially with increases in temperature. Because the flame temperature of oil fuel is higher than that of natural gas, NO_x emissions are higher for operations using oil fuel than natural gas.

Uncontrolled NO_x emission levels were provided by gas turbine manufacturers in parts per million, by volume (ppmv). Unless stated otherwise, all emission levels shown in ppmv are corrected to 15 percent O_2 . These emission levels were used to calculate uncontrolled NO_x emission factors, in pounds (lb) of NO_x per million British thermal units (Btu) ($\text{lb NO}_x/\text{MMBtu}$). Sample calculations are shown in Appendix A. These uncontrolled emission levels and emission factors for both natural gas and oil fuel are presented in Table 2-1

TABLE 2-1. UNCONTROLLED NO_x EMISSION FACTORS FOR GAS TURBINES

Manufacturer	Model No.	Output, MW	NO _x emissions, ppmv, dry and corrected to 15% O ₂		NO _x emissions factor, lb NO _x /MMBtu ^a	
			Natural gas	Distillate oil No. 2	Natural gas	Distillate oil No. 2
Solar	Saturn	1.1	99	150	0.397	0.551
	Centaur	3.3	130	179	0.521	0.658
	Centaur "H"	4.0	105	160	0.421	0.588
	Taurus	4.5	114	168	0.457	0.618
	Mars T12000	8.8	178	267	0.714	0.981
	Mars T14000	10.0	199	NA ^b	0.798	NA ^b
GM/Allison	501-KB5	4.0	155	231	0.622	0.849
	570-KA	4.9	101	182	0.405	0.669
	571-KA	5.9	101	182	0.405	0.669
General Electric	LM1600	12.8	144	237	0.577	0.871
	LM2500	21.8	174	345	0.698	1.27
	LM5000	33.1	185	364	0.742	1.34
	LM6000	41.5	220	417	0.882	1.53
	MS5001P	26.3	142	211	0.569	0.776
	MS6001B	38.3	148	267	0.593	0.981
	MS7001EA	83.5	154	228	0.618	0.838
	MS7001F	123	179	277	0.718	1.02
	MS9001EA	150	176	235	0.706	0.864
	MS9001F	212	176	272	0.706	1.00
Asea Brown Boveri	GT8	47.4	430	680	1.72	2.50
	GT10	22.6	150	200	0.601	0.735
	GT11N	81.6	390	560	1.56	2.06
	GT35	16.9	300	360	1.20	1.32
Westinghouse	W261B11/12	52.3	220	355	0.882	1.31
	W501D5	119	190	250	0.762	0.919
Siemens	V84.2	105	212	360	0.850	1.32
	V94.2	153	212	360	0.850	1.32
	V64.3	61.5	380	530	1.52	1.95
	V84.3	141	380	530	1.52	1.95
	V94.3	203	380	530	1.52	1.95

^aBased on emission levels provided by gas turbine manufacturers, corresponding to rated load at ISO conditions.

NO_x emissions calculations are shown in Appendix A.

^bNot available.

. Uncontrolled NO_x emission levels range from 99 to 430 ppmv for natural gas fuel and from 150 to 680 ppmv for distillate oil fuel. Corresponding uncontrolled emission factors range from 0.397 to 1.72 lb NO_x/MMBtu and 0.551 to 2.50 lb NO_x/MMBtu for natural gas and distillate oil fuels, respectively. Because thermal NO_x is primarily a function of combustion temperature, NO_x emission rates vary with combustor design. There is no discernable correlation between turbine size and NO_x emission levels evident in Table 2-1.

2.2 CONTROL TECHNIQUES AND CONTROLLED NO_x EMISSION LEVELS

Reductions in NO_x emissions can be achieved using combustion controls or flue gas treatment. Available combustion controls are water or steam injection and dry low-NO_x combustion designs. Selective catalytic reduction is the only available flue gas treatment.

2.2.1 Combustion Controls

Combustion control using water or steam lowers combustion temperatures, which reduces thermal NO_x formation. Fuel NO_x formation is not reduced with this technique. Water or steam, treated to quality levels comparable to boiler feedwater, is injected into the combustor and acts as a heat sink to lower

flame temperatures. This control technique is available for all new turbine models and can be retrofitted to most existing installations.

Although uncontrolled emission levels vary widely, the range of achievable controlled emission levels using water or steam injection is relatively small. Controlled NO_x emission levels range from 25 to 42 ppmv for natural gas fuel and from 42 to 75 ppmv for distillate oil fuel. Achievable guaranteed controlled emission levels, as provided by turbine manufacturers, are shown for individual turbine models in Figures 2-1 and 2-2

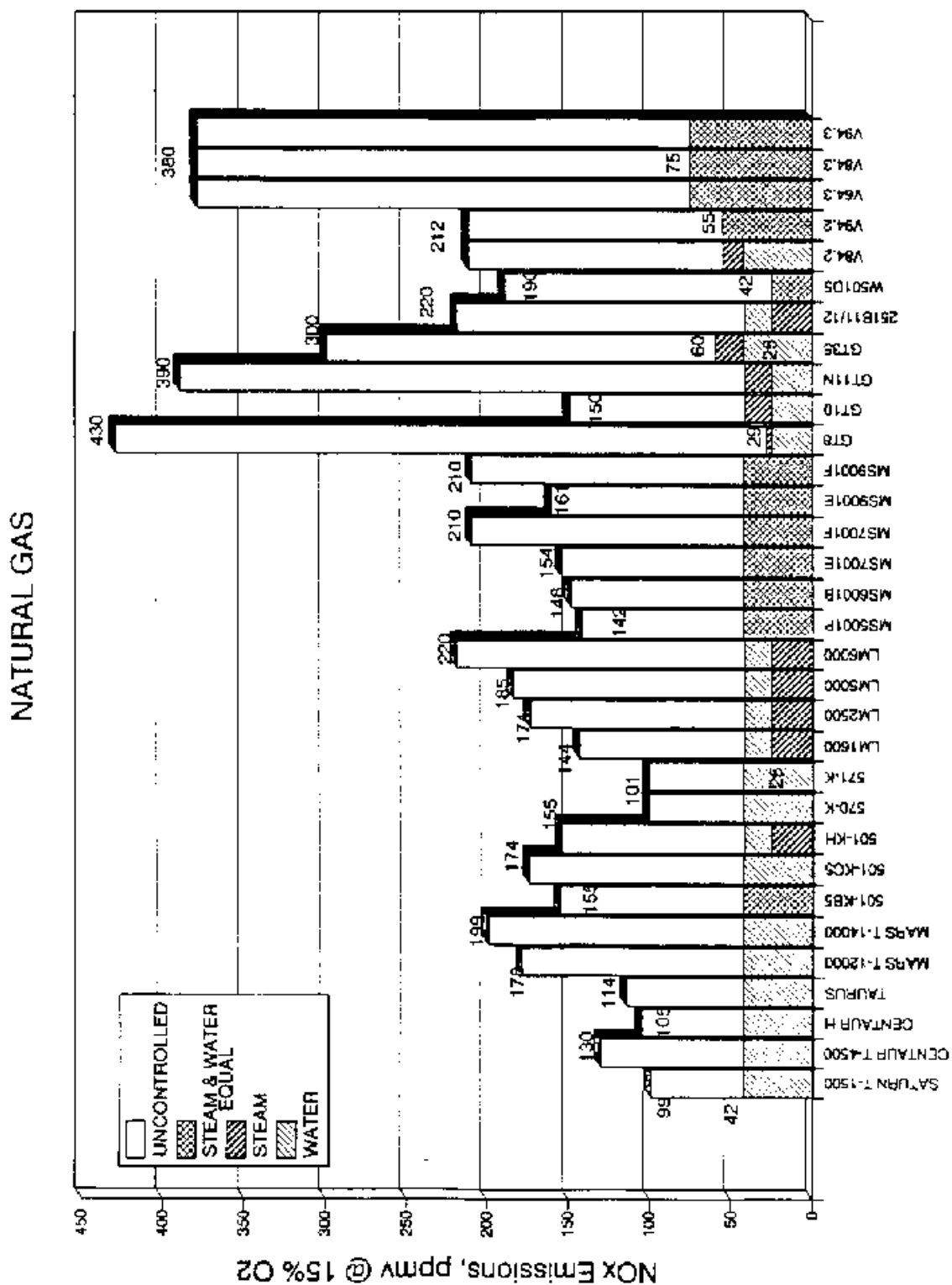


Figure 2-1. Uncontrolled NO_x emission levels and gas turbine manufacturers' guaranteed controlled levels using wet injection. Natural gas fuel.

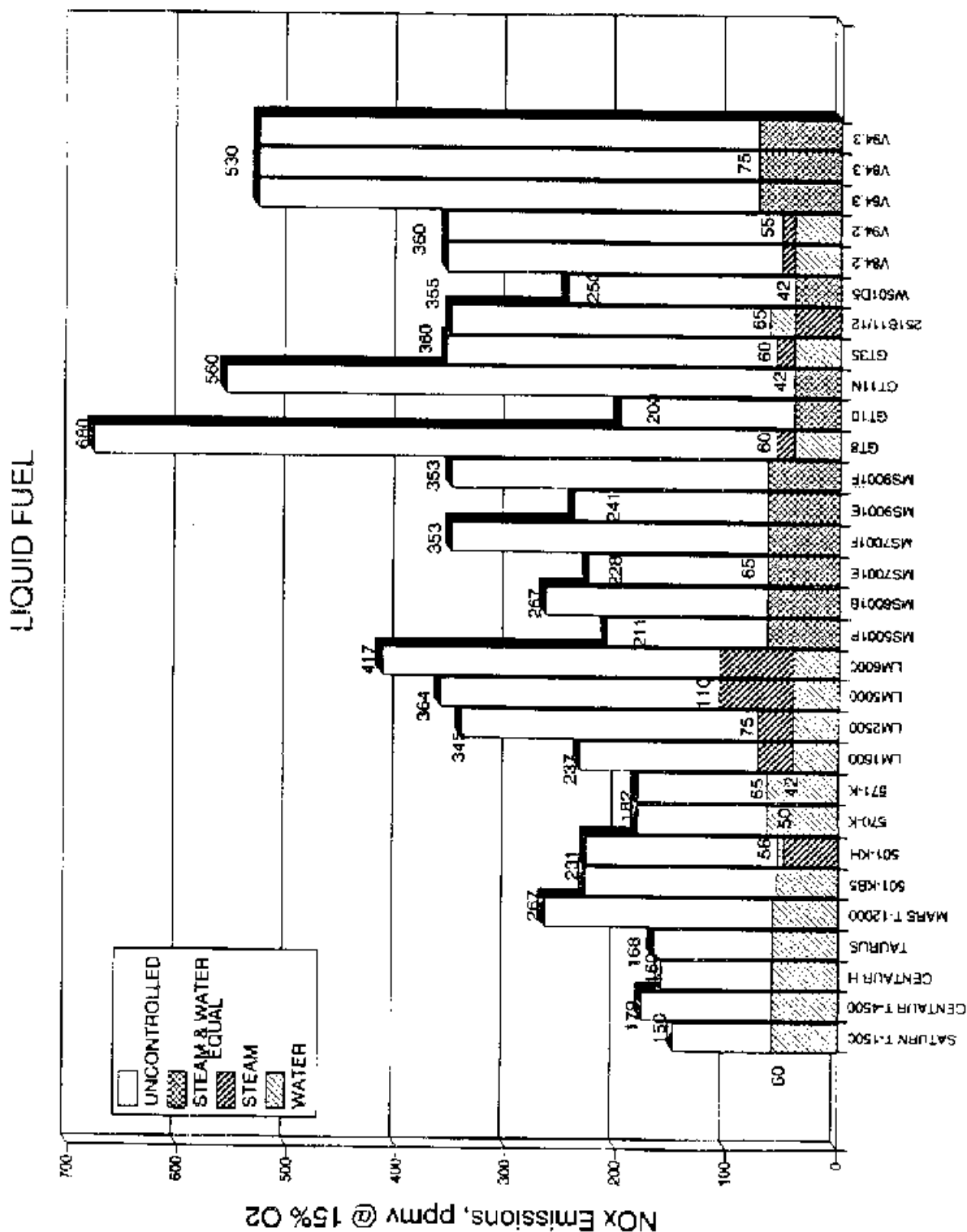


Figure 2-2. Uncontrolled NO_x emission levels and gas turbine manufacturers' guaranteed controlled levels using wet injection. Distillate oil fuel.

for natural gas and oil fuels, respectively.

The decision whether to use water versus steam injection for NO_x reduction depends on many factors, including the availability of steam injection nozzles and controls from the turbine manufacturer, the availability and cost of steam at the site, and turbine performance and maintenance impacts. This decision is usually driven by site-specific environmental and economic factors.

A system that allows treated water to be mixed with the fuel prior to injection is also available. Limited testing of water-in-oil emulsions injected into the turbine combustor have achieved NO_x reductions equivalent to direct water injection but at reduced water-to-fuel rates. The vendor reports a similar system is available for natural gas-fired applications.

Dry low-NO_x combustion control techniques reduce NO_x emissions without injecting water or steam. Two designs, lean premixed combustion and rich/quench/lean staged combustion have been developed.

Lean premixed combustion designs reduce combustion temperatures, thereby reducing thermal NO_x. Like wet injection, this technique is not effective in reducing fuel NO_x. In a conventional turbine combustor, the air and fuel are introduced at an approximately stoichiometric ratio and air/fuel mixing occurs simultaneously with combustion. A lean premixed combustor design premixes the fuel and air prior to combustion. Premixing results in a homogeneous air/fuel mixture, which minimizes

localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_x emissions. A lean air-to-fuel ratio approaching the lean flammability limit is maintained, and the excess air acts as a heat sink to lower combustion temperatures, which lowers thermal NO_x formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment.

Lean premixed combustors are currently available from several turbine manufacturers for a limited number of turbine models. Development of this technology is ongoing, and availability should increase in the coming years. All turbine manufacturers state that lean premixed combustors are designed for retrofit to existing installations.

Controlled NO_x emission levels using dry lean premixed combustion range from 9 to 42 ppmv for operation on natural gas fuel. The low end of this range (9 to 25 ppmv) has been limited to turbines above 20 megawatts (MW) (27,000 horsepower [hp]); to date, three manufacturers have guaranteed controlled NO_x emission levels of 9 ppmv at one or more installations for utility-sized turbines. Controlled NO_x emissions from smaller turbines typically range from 25 to 42 ppmv. For operation on distillate oil fuel, water or steam injection is required to achieve controlled NO_x emissions levels of approximately 65 ppmv. Development continues for oil-fueled operation in lean premixed designs, however, and one turbine manufacturer reports having achieved controlled NO_x emission levels below 50 ppmv in limited testing on oil fuel without wet injection.

A second dry low-NO_x combustion design is a rich/quench/lean staged combustor. Air and fuel are partially combusted in a fuel-rich primary stage, the combustion products are then rapidly quenched using water or air, and combustion is completed in a fuel-lean secondary stage. The fuel-rich primary stage inhibits NO_x formation due to low O₂ levels. Combustion temperatures in the fuel-lean secondary stage are below NO_x formation temperatures as a result of the quenching process and the presence of excess air. Both thermal and fuel NO_x are controlled with this design. Limited testing with fuels including natural

gas and coal have achieved controlled NO_x emissions of 25 ppmv. Development of this design continues, however, and currently the rich/quench/lean combustor is not available for production turbines.

2.2.2 Selective Catalytic Reduction

This flue gas treatment technique uses an ammonia (NH₃) injection system and a catalytic reactor to reduce NO_x. An injection grid disperses NH₃ in the flue gas upstream of the catalyst, and NH₃ and NO_x are reduced to N₂ and water (H₂O) in the catalyst reactor. This control technique reduces both thermal NO_x and fuel NO_x.

Ammonia injection systems are available that use either anhydrous or aqueous NH₃. Several catalyst materials are available. To date, most SCR installations use a base-metal catalyst with an operating temperature window ranging from approximately 260° to 400°C (400° to 800°F). The exhaust temperature from the gas turbine is typically above 480°C (900°F), so the catalyst is located within a heat recovery steam generator (HRSG) where temperatures are reduced to a range compatible with the catalyst operating temperature. This operating temperature requirement has, to date, limited SCR to cogeneration or combined-cycle applications with HRSG's to reduce flue gas temperatures. High-temperature zeolite catalysts, however, are now available and have operating temperature windows of up to 600°C (1100°F), which is suitable for installation directly downstream of the turbine. This high-temperature zeolite catalyst offers the potential for SCR applications with simple cycle gas turbines.

To achieve optimum long-term NO_x reductions, SCR systems must be properly designed for each application. In addition to temperature considerations, the NH₃ injection rate must be carefully controlled to maintain an NH₃/NO_x molar ratio that effectively reduces NO_x and avoids excessive NH₃ emissions downstream of the catalyst, known as ammonia slip. The selected catalyst formulation must be resistant to potential masking and/or poisoning agents in the flue gas.

To date, most SCR systems in the United States have been installed in gas-fired turbine applications, but improvements in SCR system designs and experience on alternate fuels in Europe and Japan suggest that SCR systems are suitable for firing distillate oil and other sulfur-bearing fuels. These fuels produce sulfur dioxide (SO_2), which may oxidize to sulfite (SO_3) in the catalyst reactor. This SO_3 reacts with NH_3 slip to form ammonium salts in the low-temperature section of the HRSG and exhaust ductwork. The ammonium salts must be periodically cleaned from the affected surfaces to avoid fouling and corrosion as well as increased back-pressure on the turbine. Advances in catalyst formulations include sulfur-resistant catalysts with low SO_2 oxidation rates. By limiting ammonia slip and using these sulfur-resistant catalysts, ammonium salt formation can be minimized.

Catalyst vendors offer NO_x reduction efficiencies of 90 percent with ammonia slip levels of 10 ppmv or less. These emission levels are warranted for 2 to 3 years, and all catalyst vendors contacted accept return of spent catalyst reactors for recycle or disposal.

Controlled NO_x emission levels using SCR are typically 9 ppmv or less for gas-fueled turbine installations. With the exception of one site, all identified installations operate the SCR system in combination with combustion controls that reduce NO_x emission levels into the SCR to a range of 25 to 42 ppmv. Most continuous-duty turbine installations fire natural gas; there is limited distillate oil-fired operating experience in the United States. Several installations with SCR in the northeast United States that use distillate oil as a back-up fuel have controlled NO_x emission limits of 18 ppmv for operation on distillate oil fuel.

2.3 COSTS AND COST EFFECTIVENESS FOR NO_x CONTROL TECHNIQUES

Capital costs and cost effectiveness were developed for the available NO_x control techniques. Capital costs are presented in Section 2.3.1. Cost-effectiveness figures, in \$/ton of NO_x

removed, are shown in Section 2.3.2. All costs presented are in 1990 dollars.

2.3.1 Capital Costs

Capital costs are the sum of purchased equipment costs, taxes and freight charges, and installation costs. Purchased equipment costs were estimated based on information provided by equipment manufacturers, vendors, and published sources. Taxes, freight, and installation costs were developed based on factors recommended in the Office of Air Quality and Planning and Standards Control Cost Manual (Fourth Edition). Capital costs for combustion controls and SCR are presented in Sections 2.3.1.1 and 2.3.1.2, respectively.

2.3.1.1 Combustion Controls Capital Costs. Capital costs for wet injection include a mixed bed demineralizer and reverse-osmosis water treatment system and an injection system consisting of pumps, piping and hardware, metering controls, and injection nozzles. All costs for wet injection are based on the availability of water at the site; no costs have been included for transporting water to the site. These costs apply to new installations; retrofit costs would be similar except that turbine-related injection hardware and metering controls purchased from the turbine manufacturer may be higher for retrofit applications.

The capital costs for wet injection are shown in Figure 2-3, and range from \$388,000 for a 3.3 MW (4,430 hp) turbine to \$4,830,000 for a 161 MW (216,000 hp) turbine.

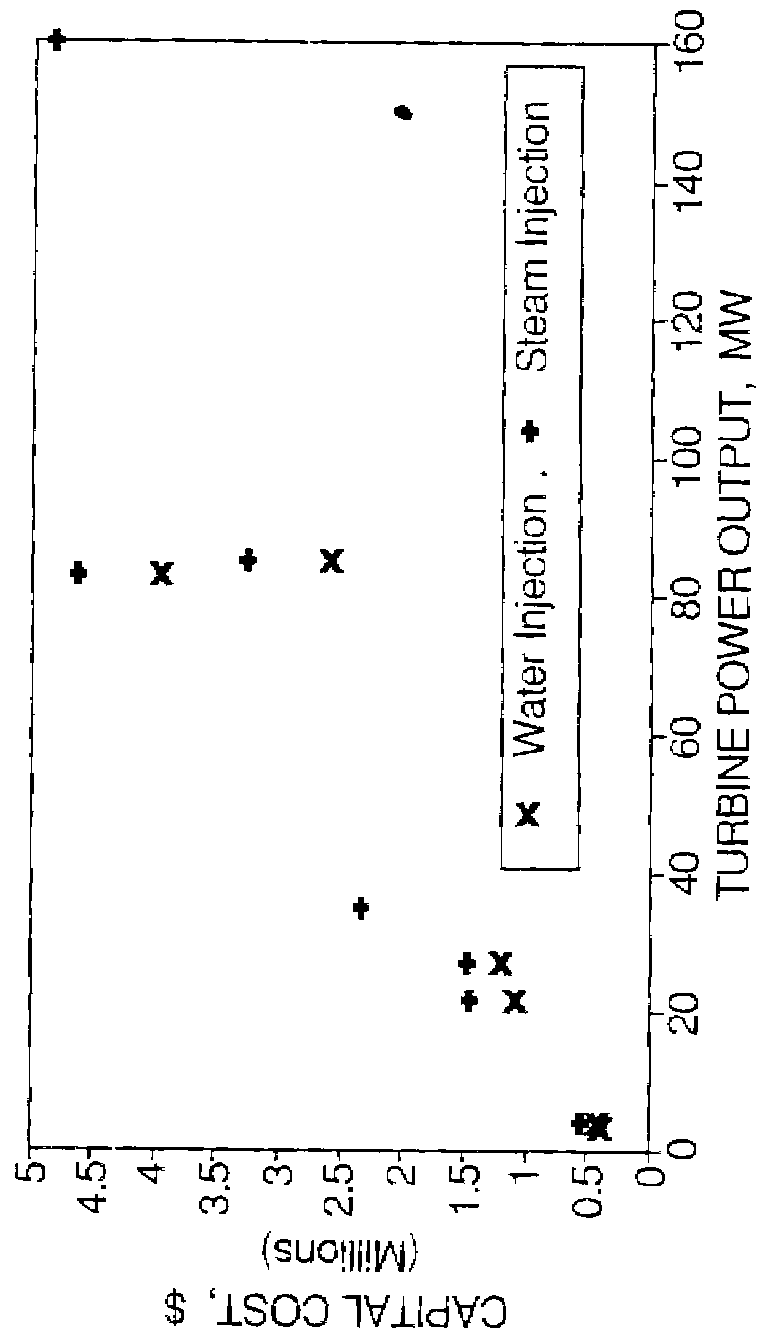


Figure 2-3. Capital costs for water or steam injection.

These capital costs include both water and steam injection systems for use with either gas or distillate oil fuel applications. Figure 2-3 shows that the capital costs for steam injection are slightly higher than those for water injection for turbines in the 3 to 25 MW (4,000 to 33,500 hp) range.

The capital costs for dry low-NO_x combustors are the incremental costs for this design over a conventional combustor and apply to new installations. Turbine manufacturers estimate retrofit costs to be approximately 40 to 60 percent higher than new equipment costs. Incremental capital costs for dry low-NO_x

combustion were provided by turbine manufacturers and are presented in Figure 2-4.

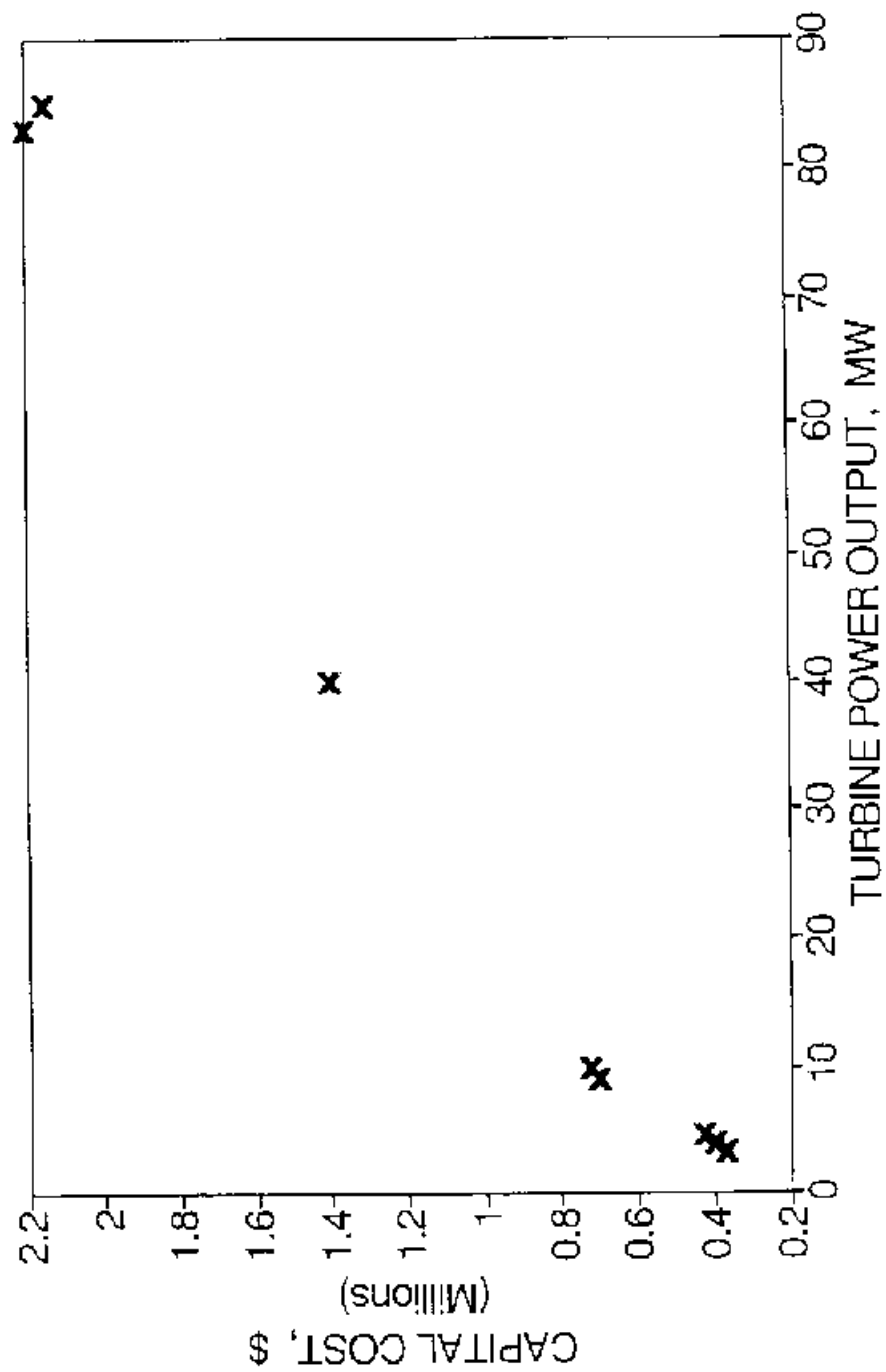


Figure 2-4. Capital costs for dry low-NO_x combustion.

The incremental capital costs range from \$375,000 for a 3.3 MW (4,430 hp) turbine to \$2.2 million for an 85 MW (114,000 hp) machine. Costs were not available for turbines above 85 MW (114,000 hp).

When evaluated on a \$/MW (\$/hp) basis, the capital costs for wet injection or dry low-NO_x combustion controls are highest for the smallest turbines and decrease exponentially with increasing turbine size. The range of capital costs for combustion controls, in \$/MW, and the effect of turbine size on capital costs are shown in Figure 2-5.

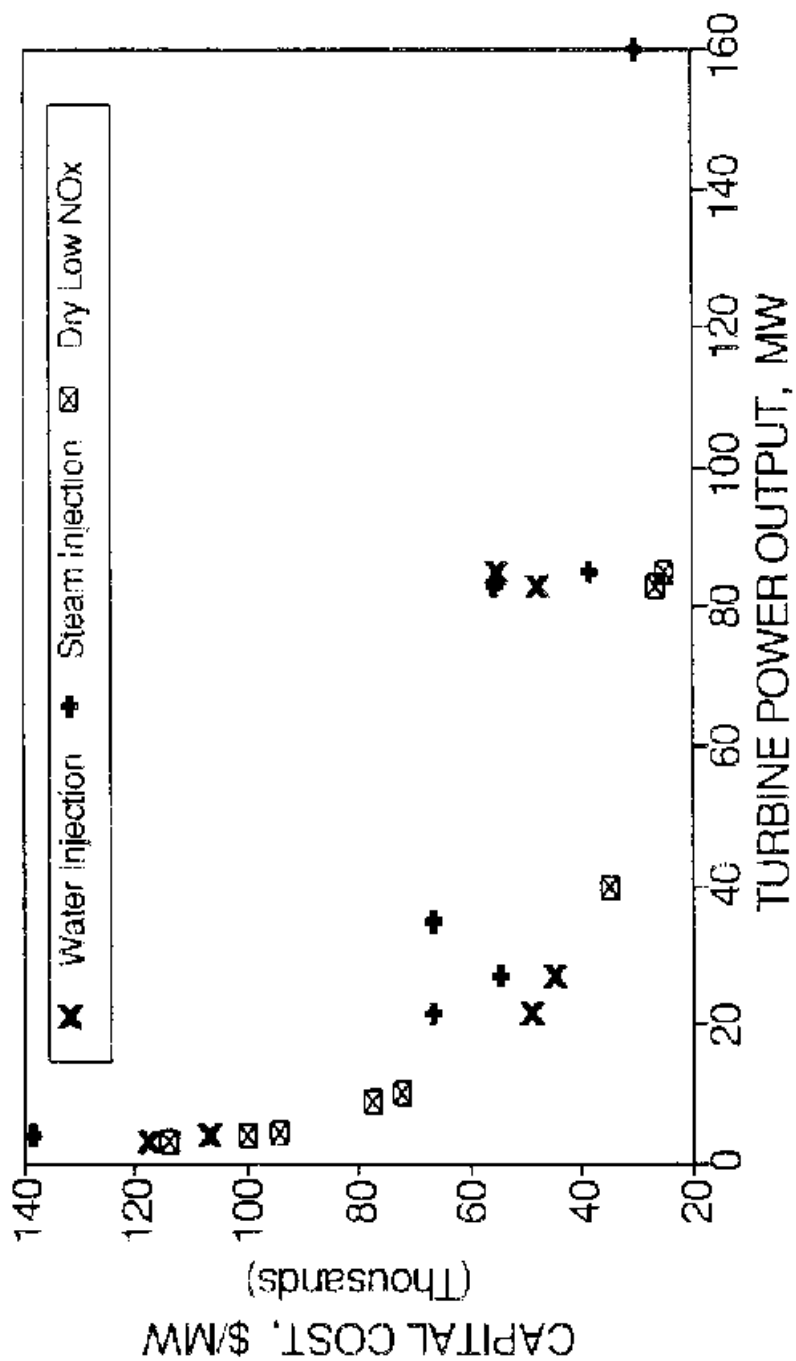


Figure 2-5. Capital costs, in \$/MW, for combustion controls.

For wet injection, the capital costs range from a high of \$138,000/MW (\$103/hp) for a 3.3 MW (4,430 hp) turbine to a low of \$29,000/MW (\$22/hp) for a 161 MW (216,000 hp) turbine. Corresponding capital cost figures for dry low-NO_x combustion range from \$114,000/MW (\$85/hp) for a 3.3 MW (4,430 hp) unit to \$26,000/MW (\$19/hp) for an 85 MW (114,000 hp) machine.

2.3.1.2 SCR Capital Costs. Capital costs for SCR include the catalyst reactor, ammonia storage and injection system, and controls and monitoring equipment. A comparison of available cost estimates for base-metal catalyst systems and high-temperature zeolite catalyst systems indicates that the costs for these systems are similar, so a single range of costs was developed that represents all SCR systems, regardless of catalyst type or turbine cycle (i.e., simple, cogeneration, or combined cycle).

The capital costs for SCR, shown in Figure 2-6, range from \$622,000 for a 3.3 MW (4,430 hp) turbine to \$8.46 million for a 161 MW (216,000 hp) turbine.

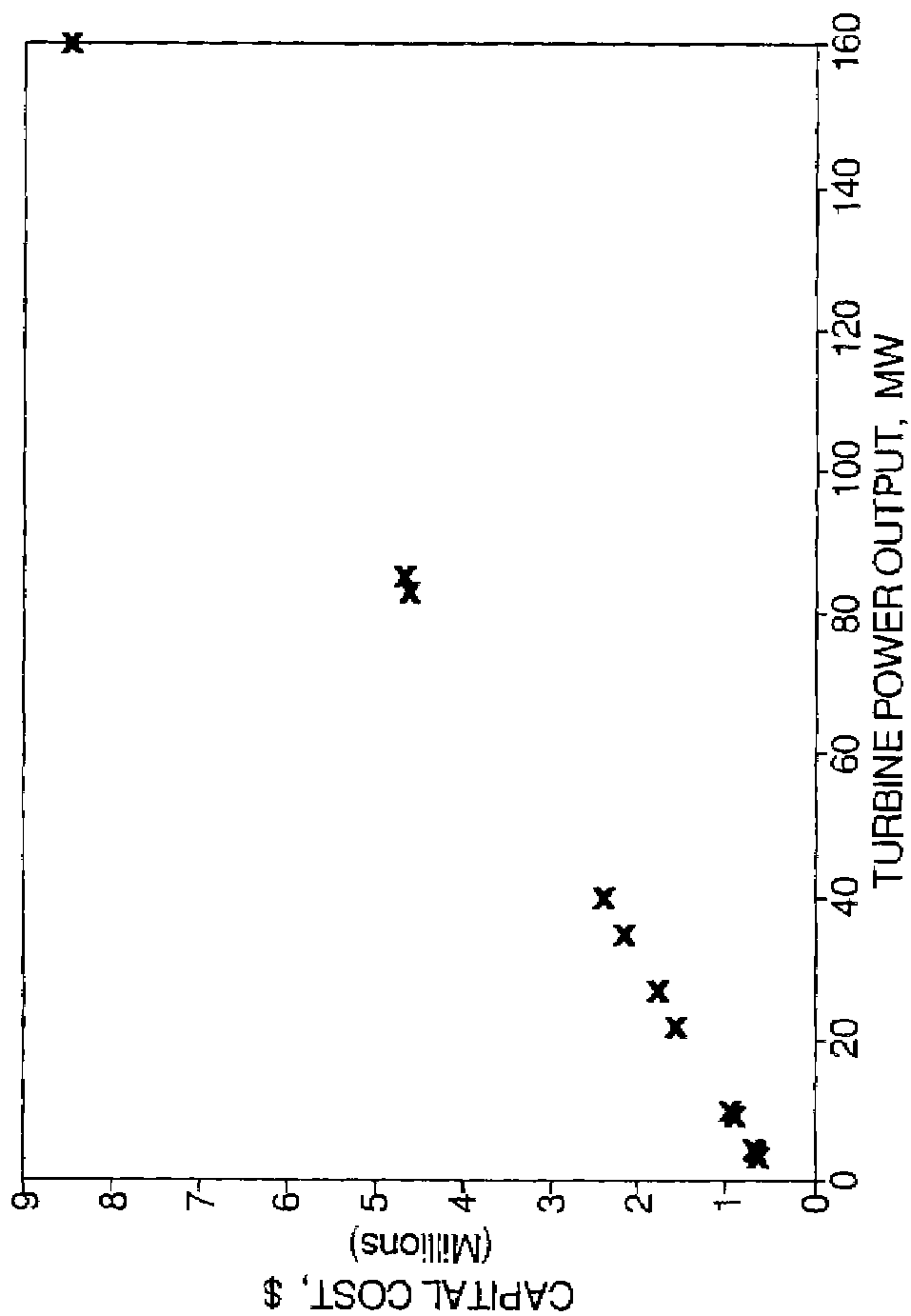


Figure 2-6. Capital costs for selective catalytic reduction.

Figure 2-7 plots capital costs on a \$/MW basis and shows that these costs are highest for the smallest turbine, at \$188,000/MW (\$140/hp) for a 3.3 MW (4,430 hp) unit, and decrease exponentially with increasing turbine size to \$52/MW (\$40/hp) for a 161 MW (216,000 hp) machine.

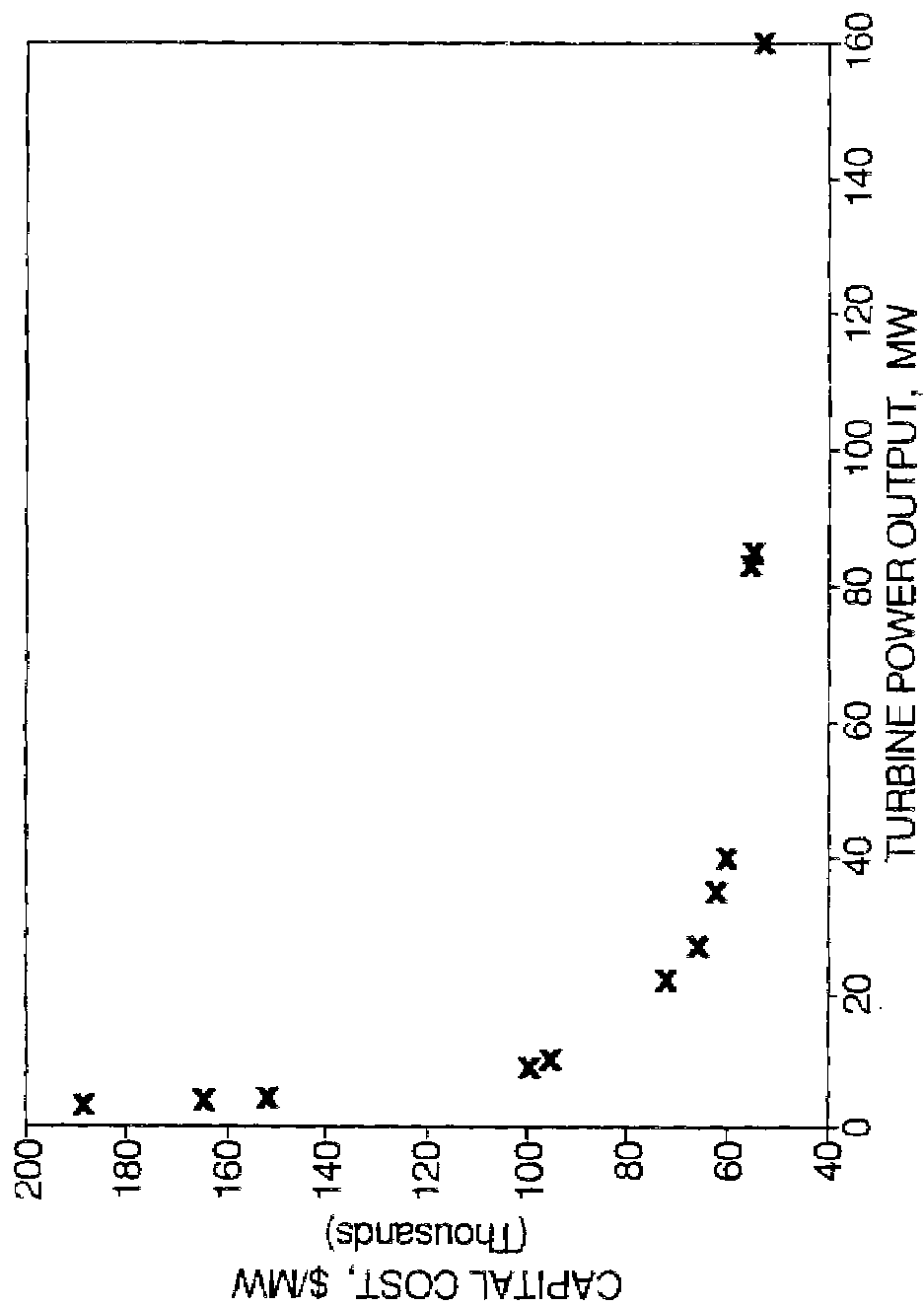


Figure 2-7. Capital costs, in \$/MW, for selective catalytic reduction.

These costs apply to new installations firing natural gas as the primary fuel. No SCR sites using oil as the primary fuel were identified, and costs were not available. For this

reason, the costs for gas-fired applications were also used for oil-fired sites. Retrofit SCR costs could be considerably higher than those shown here for new installations, especially if an existing HRSG and ancillary equipment must be moved or modified to accommodate the SCR system.

2.3.2 Cost Effectiveness

The cost effectiveness, in \$/ton of NO_x removed, was developed for each NO_x control technique. The cost effectiveness for a given control technique is calculated by dividing the total annual cost by the annual NO_x reduction, in tons. The cost effectiveness presented in this section correspond to 8,000 annual operating hours. Total annual costs were calculated as the sum of all annual operating costs and annualized capital costs. Annual operating costs include costs for incremental fuel, utilities, maintenance, applicable performance penalties, operating and supervisory labor, plant overhead, general and administrative, and taxes and insurance. Capital costs were annualized using the capital recovery factor method with an equipment life of 15 years and an annual interest rate of 10 percent. Cost-effectiveness figures for combustion controls and SCR are presented in Sections 2.3.2.1 and 2.3.2.2, respectively.

2.3.2.1 Combustion Controls Cost Effectiveness. Cost effectiveness for combustion controls is shown in Figure 2-8.

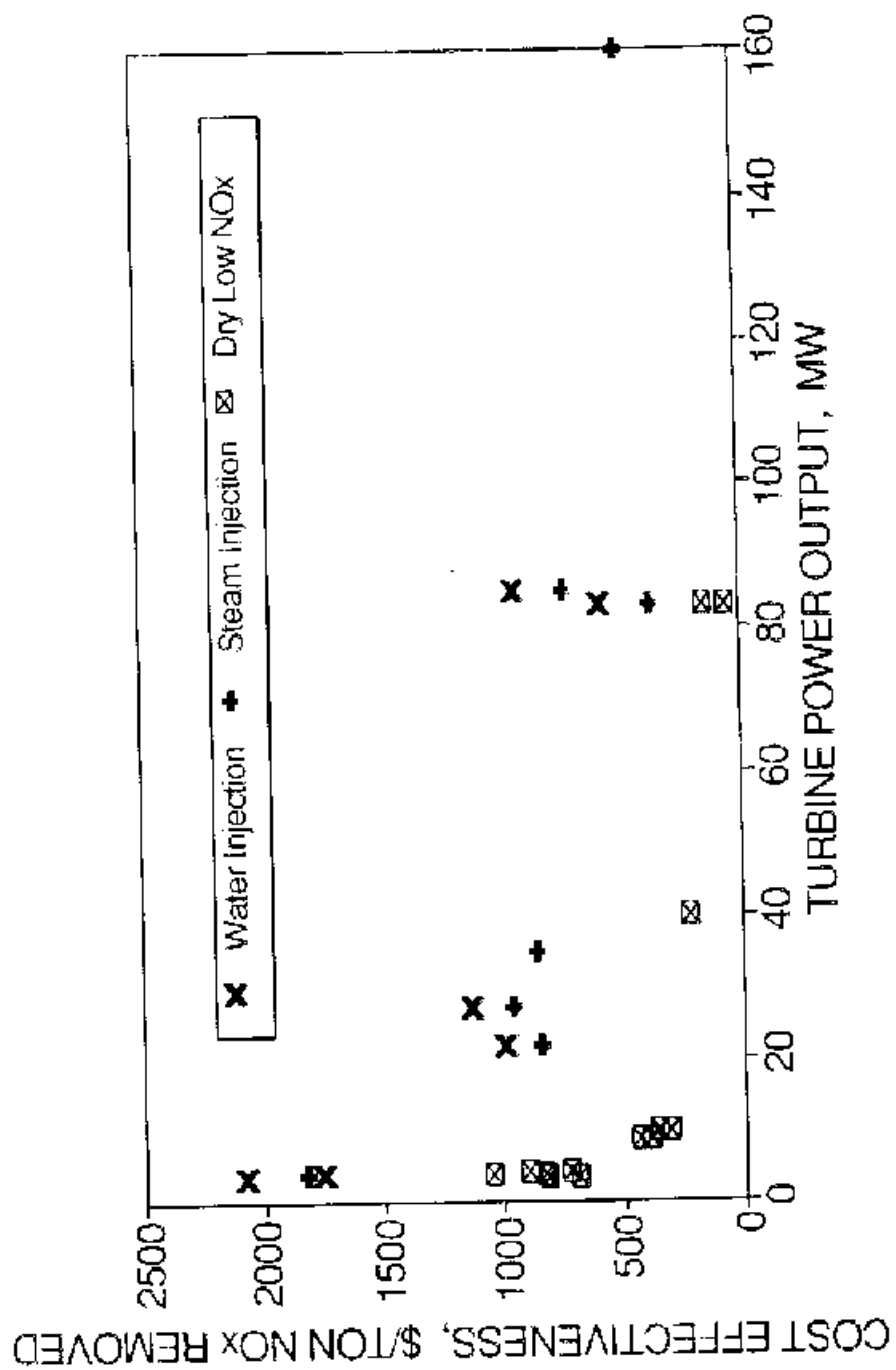


Figure 2-8. Cost effectiveness of combustion controls.

Figure 2-8 indicates that cost effectiveness for combustion controls is highest for the smallest turbines and decreases exponentially with decreasing turbine size. Figure 2-8 also shows that the range of cost effectiveness for water injection is similar to that for steam injection, primarily because the total annual costs and achievable controlled NO_x emission levels for water and steam injection are similar. The cost-effectiveness range for dry low-NO_x combustion is lower than that for wet NO_x levels are similar (25 to 42 ppmv), due to the lower total annual costs for dry low-NO_x combustion.

For water injection, cost effectiveness, in \$/ton of NO_x removed, ranges from \$2,080 for a 3.3 MW (4,430 hp) unit to \$575 for an 83 MW (111,000 hp) turbine and \$937 for an 85 MW (114,000 hp) turbine. For steam injection, cost effectiveness is \$1,830 for a 3.3 MW (4,430 hp), decreasing to \$375 for an 83 MW (111,000 hp) turbine, and increasing to \$478 for a 161 MW (216,000 hp) turbine. The relatively low cost effectiveness for the 83 MW (111,000 hp) turbine is due to this particular turbine's high uncontrolled NO emissions, which result in a relatively high NO_x removal efficiency and lower cost effectiveness. The cost effectiveness shown in Figure 2-8

number of oil-fired applications with water injection indicates that the cost effectiveness ranges from 70 to 85 percent of the

NO_x removal efficiency achieved in oil-fired applications.

For dry low-NO_x combustion, cost effectiveness, in \$/ton of NO_x removed, ranges from \$1,060 for a 4.0 MW (5,360 hp) turbine down to \$154 for an 85 MW (114,000 hp) machine. A cost effectiveness of \$57 was calculated for the 83 MW (111,000 hp) unit. Again, the relatively high uncontrolled NO_x emissions and the resulting high NO_x removal efficiency for this turbine model yields a relatively low cost-effectiveness figure. Current dry low-NO_x combustion designs do not achieve NO_x reductions with oil fuels, so the cost-effectiveness values shown in this section apply only to gas-fired applications.

2.3.2.2 SCR Cost Effectiveness. Cost effectiveness for SCR was calculated based on the use of combustion controls upstream of the catalyst to reduce NO_x emissions to a range of 25 to 42 ppmv at the inlet to the catalyst. This approach was used because all available SCR cost information is for SCR applications used in combination with combustion controls and all but one of the 100+ SCR installations in the United States operate in combination with combustion controls. For this cost analysis, a 5-year catalyst life and a 9 ppmv controlled NO_x emission level was used to calculate cost effectiveness for SCR.

Figure 2-9 presents SCR cost effectiveness. Figure 2-9 shows that, like combustion controls, SCR cost effectiveness is highest for the smallest turbines and decreases exponentially with decreasing turbine size.

Also, because this cost analysis uses a 9 ppmv controlled NO_x emission level for SCR, NO_x reduction efficiencies are higher where the NO_x emission level into the SCR is 42 ppmv than for applications with a 25 ppmv level. Cost effectiveness corresponding to an inlet NO_x emission level of 42 ppmv, in \$/ton of NO_x removed, ranges from a high of \$10,800 for a 3.3 MW (4430 hp) turbine to \$3,580 for a 161 MW (216,000 hp) turbine. For an inlet NO_x emission level of 25 ppmv, the cost-effectiveness range shifts higher, from \$22,100 for a 3.3 MW (4,430 hp) installation to \$6,980 for an 83 MW (111,000 hp) site.

The range of cost effectiveness for SCR shown in Figure 2-9 applies to gas-fired applications. Cost effectiveness developed for a limited number of oil-fired installations using capital costs from gas-fired applications yields cost-effectiveness values ranging from approximately 70 to 77 percent of those for gas-fired sites. The lower cost-effectiveness figures for oil-fired applications result primarily from the greater annual NO_x reductions for oil-fired applications; the gas-fired capital costs used for these oil-fired applications may understate the actual capital costs for these removal rates and actual oil-fired cost-effectiveness figures may be higher.

Combined cost-effectiveness figures, in \$/ton of NO_x removed, were calculated for the combination of combustion controls plus SCR by dividing the sum of the total annual costs by the sum of the NO_x removed for both control techniques. The controlled NO_x emission level for the combination of controls is 9 ppmv. These combined cost-effectiveness figures are presented in Figure 2-10.

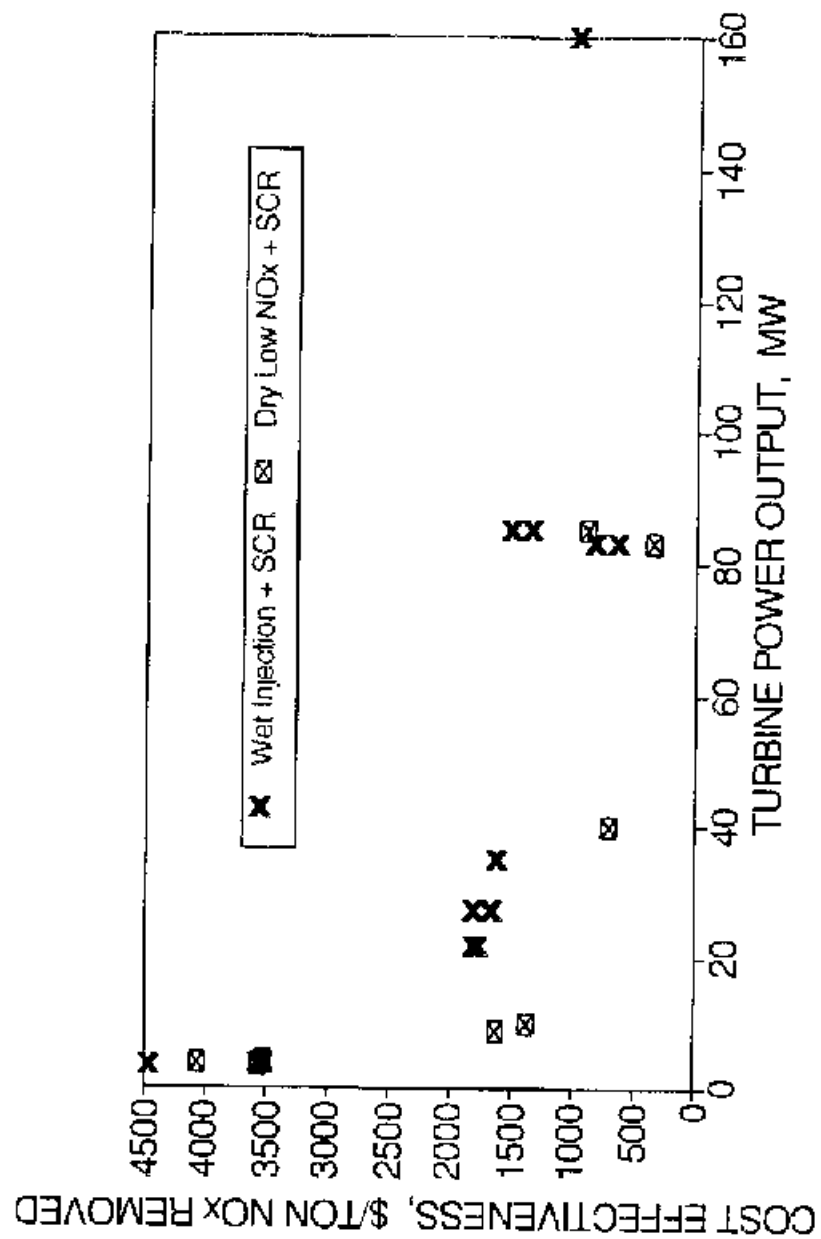


Figure 2-10. Combined cost effectiveness for combustion controls plus selective catalytic reduction.

For wet injection plus SCR, the combined cost effectiveness ranges from \$4,460 for a 3.3 MW (4,430 hp) application to \$988 for a 160 MW (216,000 hp) site. The \$645 cost-effectiveness value for the 83 MW (111,000 hp) turbine is lower than the other turbine models shown in Figure 2-10 due to

the relatively high uncontrolled NO_x emission level for this turbine, which results in relatively high NO_x removal rates and a lower cost effectiveness. For dry low-NO_x combustion plus SCR, combined cost-effectiveness values range from \$4,060 to \$348 for this turbine size range.

2.4 REVIEW OF CONTROLLED NO_x EMISSION LEVELS AND COSTS

An overview of the performance and costs for available NO_x control techniques is presented in Figure 2-11.

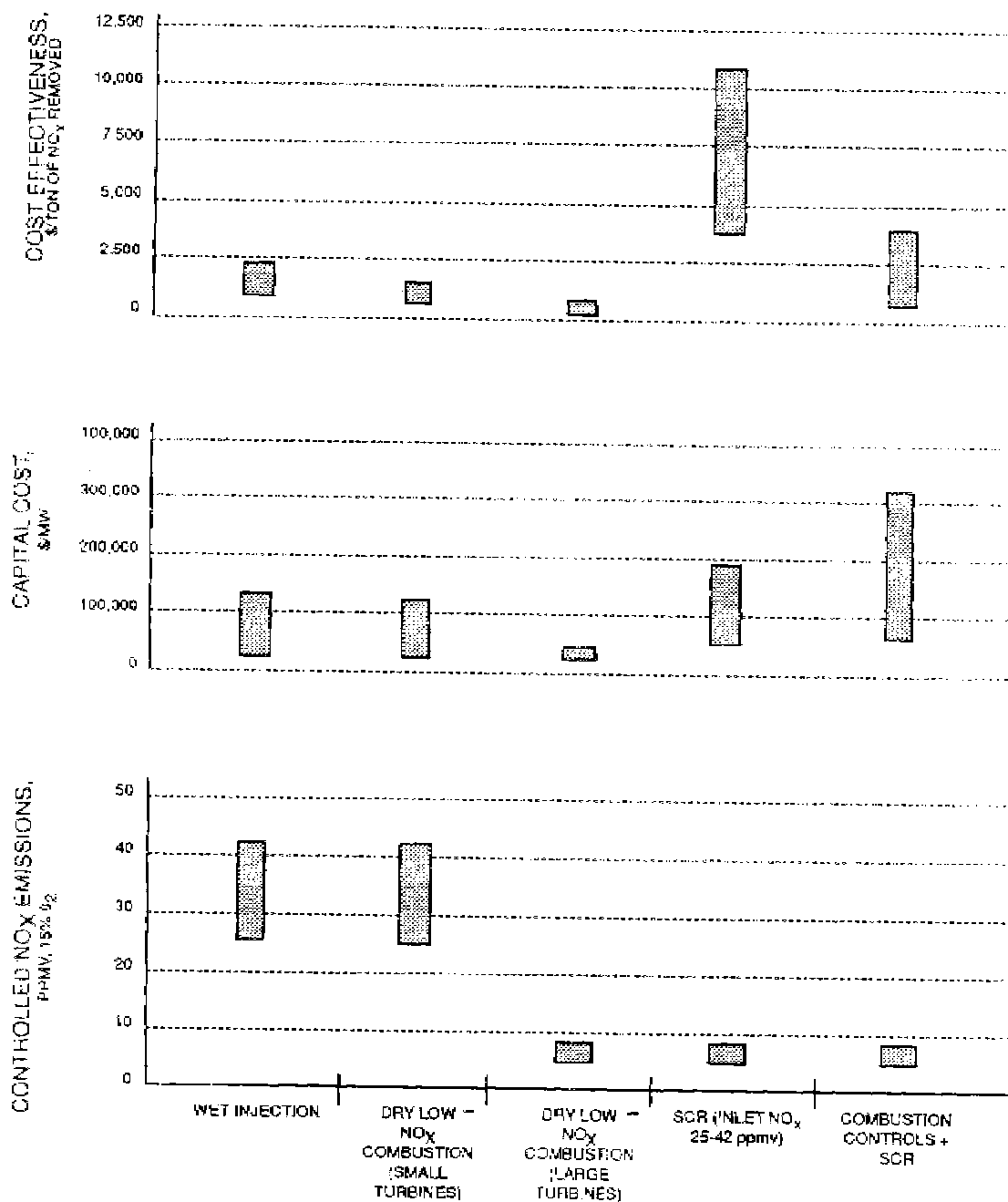


Figure 2-11. Controlled NO_x emission levels and associated capital costs and cost effectiveness for available NO_x control techniques. Natural gas fuel.

Figure 2-11 shows relative achievable controlled NO_x emission levels, capital costs, and cost effectiveness for gas-fired turbine applications. Controlled NO_x emission levels of 25 to 42 ppmv can be achieved using either wet injection or, where available, dry low-NO_x combustion. Wet injection capital costs range from \$30,000 to \$140,000 per MW (\$22 to \$104 per hp), and cost effectiveness ranges from \$375 to \$2,100 per ton of NO_x removed. Dry low-NO_x combustion capital costs range from \$25,000 to \$115,000 per MW (\$19 to \$86 per hp), and cost effectiveness ranges from \$55 to \$1,050 per ton of NO_x removed.

A controlled NO_x emission level of 9 ppmv requires the addition of SCR, except for a limited number of large turbine models for which dry low-NO_x combustion designs can achieve this level. For turbine models above 40 MW (53,600 hp), the capital costs of dry low-NO_x combustion range from \$25,000 to \$36,000 per MW (\$25 to \$27 per hp), and the cost effectiveness ranges from \$55 to \$138 per ton of NO_x removed. Adding SCR to reduce NO_x emission levels from 42 or 25 ppmv to 9 ppmv adds capital costs ranging from \$53,000 to \$190,000 per MW (\$40 to \$142 per hp) and yields cost-effectiveness values ranging from \$3,500 to \$10,500 per ton of NO_x removed. The combination of combustion controls plus SCR yields combined capital costs ranging from \$78,000 to \$330,000 per MW (\$58 to \$246 per hp) and cost-effectiveness values ranging from \$350 to \$4,500 per ton of NO_x removed.

2.5 ENERGY AND ENVIRONMENTAL IMPACTS OF NO_x CONTROL TECHNIQUES

The use of the NO_x control techniques described in this document may affect the turbine performance and maintenance

requirements and may result in increased emissions of carbon monoxide (CO), hydrocarbons (HC), and NH_3 . These potential energy and environmental impacts are discussed in this section.

Water or steam injection affects turbine performance and in some turbines also affects maintenance requirements. The increased mass flow through the turbine resulting from water or steam injection increases the available power output. The quenching effect in the combustor, however, decreases combustion efficiency, and consequently the efficiency of the turbine decreases in most applications. The efficiency reduction is greater for water than for steam injection, largely because the heat of vaporization energy cannot be recovered in the turbine. In applications where the steam can be produced from turbine exhaust heat that would otherwise be rejected to the atmosphere, the net gas turbine efficiency is increased with steam injection. Injection of water or steam into the combustor increases the maintenance requirements of the hot section of some turbine models. Water injection generally has a greater impact than steam on increased turbine maintenance. Water or steam injection has the potential to increase CO and, to a lesser extent, HC emissions, especially at water-to-fuel ratios above 0.8.

Turbine manufacturers report no significant performance impacts for lean premixed combustors. Power output and efficiency are comparable to conventional designs. No maintenance impacts are reported, although long-term operating experience is not available. Impacts on CO emissions vary for different combustor designs. Limited data from three manufacturers showed minimal or no increases in CO emissions for controlled NO_x emission levels of 25 to 42 ppmv. For a controlled NO_x level of 9 ppmv, however, CO emissions increased from 10 to 25 ppmv in one manufacturer's combustor design.

For SCR, the catalyst reactor increases the back-pressure on the turbine, which decreases the turbine power output by approximately 0.5 percent. The addition of the SCR system and associated controls and monitoring equipment increases plant maintenance requirements, but it is expected that these

maintenance requirements are consistent with maintenance schedules for other plant equipment. There is no impact on CO or HC emissions from the turbine caused by the SCR system, but ammonia slip through the catalyst reactor results in NH₃ emissions. Ammonia slip levels are typically guaranteed by SCR vendors at 10 ppmv, and operating experience indicates actual NH₃ emissions are at or below this level.

3.0 STATIONARY GAS TURBINE DESCRIPTION AND INDUSTRY APPLICATIONS

This section describes the physical components and operating cycles of gas turbines and how turbines are used in industry. Projected growth in key industries is also presented.

3.1 GENERAL DESCRIPTION OF GAS TURBINES

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. A common example of a gas turbine is the aircraft jet engine. In stationary applications, the hot combustion gases are directed through one or more fan-like turbine wheels to generate shaft horsepower rather than the thrust propulsion generated in an aircraft engine. Often the heat from the exhaust gases is recovered through an add-on heat exchanger.

Figure 3-1

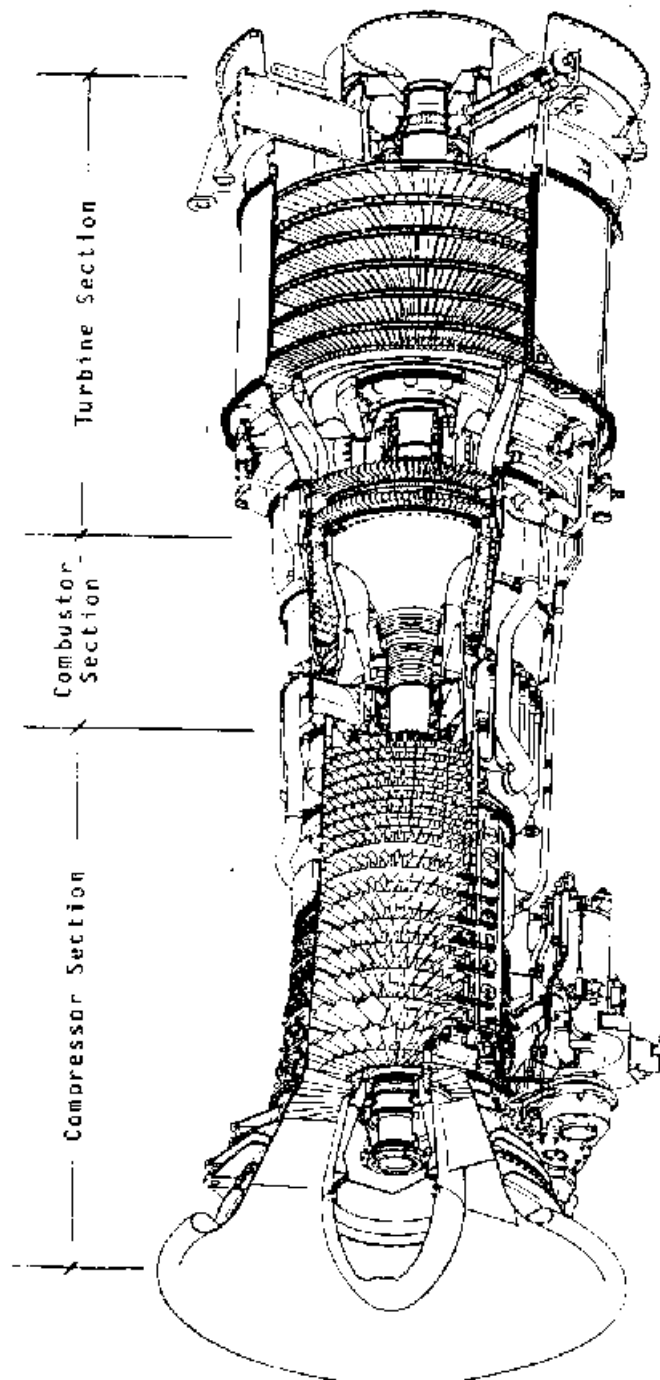
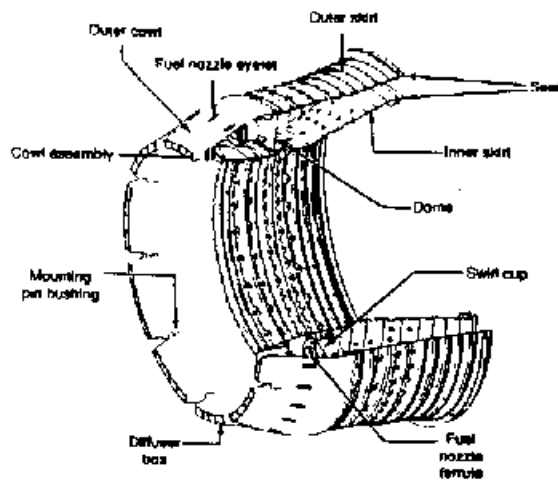


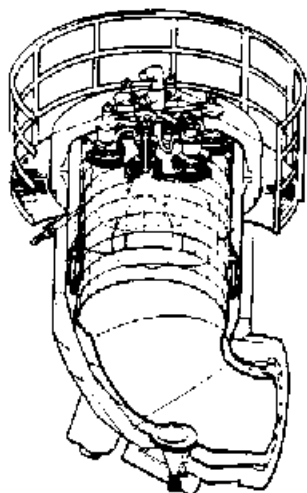
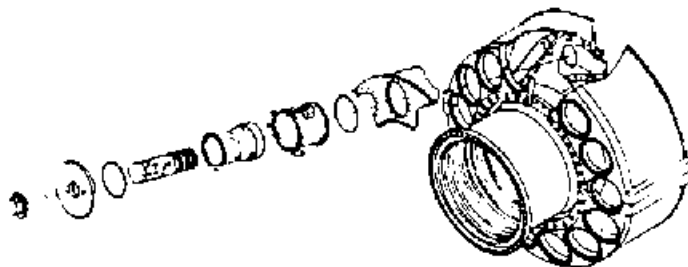
Figure 3-1. The three primary sections of a gas turbine.¹

presents a cutaway view showing the three primary sections of a gas turbine: the compressor, the combustor, and the turbine.¹ The compressor draws in ambient air and compresses it by a pressure ratio of up to 30 times ambient pressure.² The compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. There are three types of combustors: annular, can-annular, and silo. An annular combustor is a single continuous chamber roughly the shape of a doughnut that rings the turbine in a plane perpendicular to the air flow. The can-annular type uses a similar configuration but is a series of can-shaped chambers rather than a single continuous chamber. The silo combustor type is one or more chambers mounted external to the gas turbine body. These three combustor types are shown in Figure 3-2



Annular

Can-annular



Silo

Figure 3-2. Types of gas turbine combustors.³⁻⁵

; further discussion of combustors is found in Chapter 5.³⁻⁵
Flame temperatures in the combustor can reach 2000°C (3600°F).⁶
The hot combustion gases

are then diluted with additional cool air from the compressor section and directed to the turbine section at temperatures up to 1285°C (2350°F).⁶ Energy is recovered in the turbine section in the form of shaft horsepower, of which typically greater than 50 percent is required to drive the internal compressor section.⁷ The balance of the recovered shaft energy is available to drive the external load unit.

The compressor and turbine sections can each be a single fan-like wheel assembly, or stage, but are usually made up of a series of stages. In a single-shaft gas turbine, shown in Figure 3-3

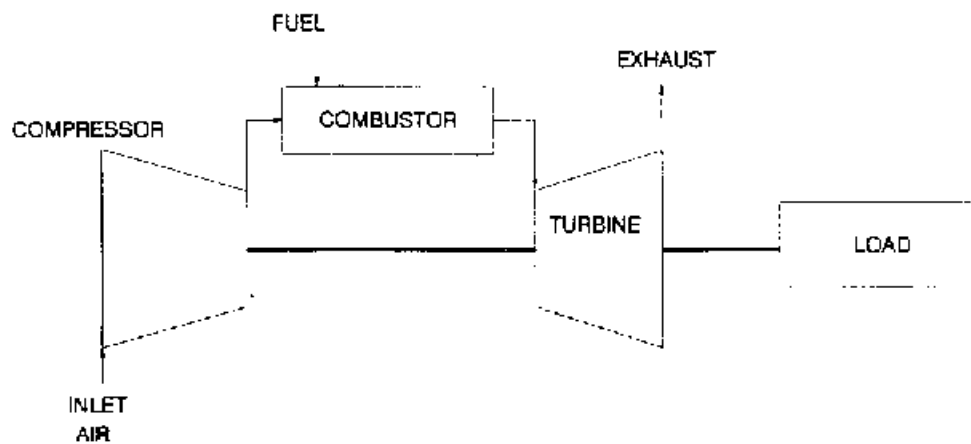


Figure 3-3. Single-shaft gas turbine.

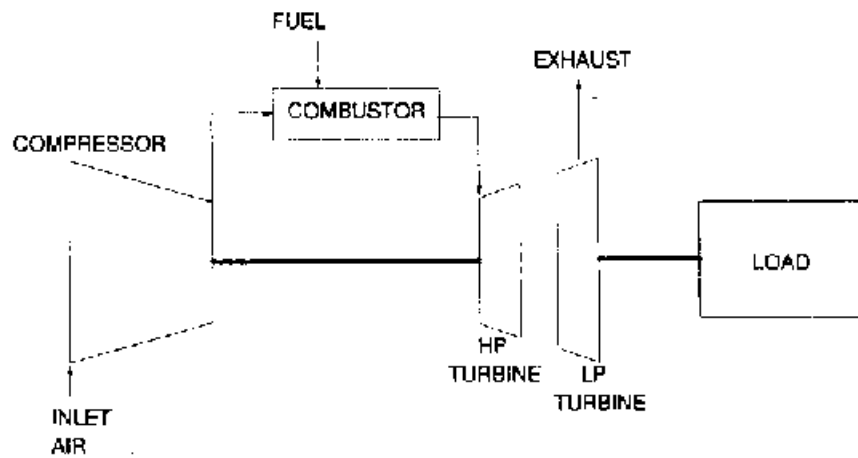


Figure 3-4. Two-shaft gas turbine.

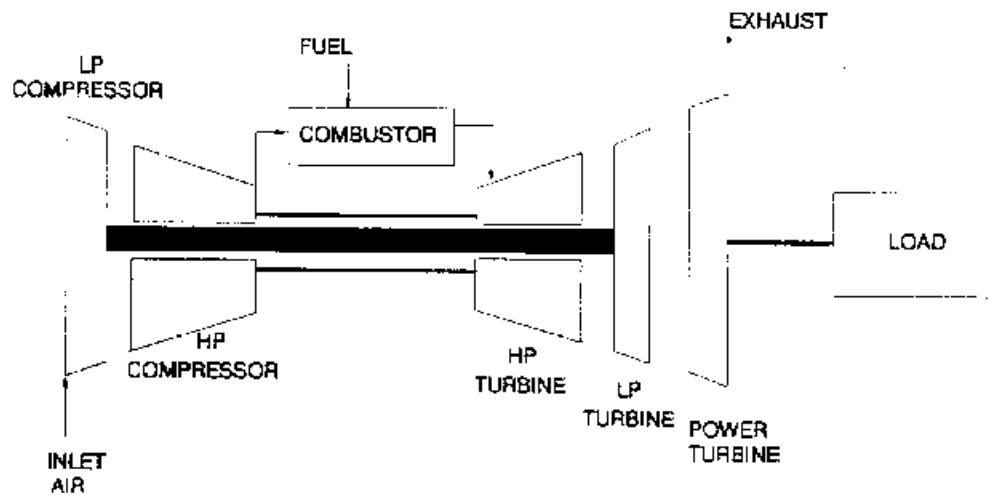


Figure 3-5. Three-shaft gas turbine.

, all compressor and turbine stages are fixed to a single, continuous shaft and operate at the same speed. A single-shaft gas turbine is typically used to drive electric generators where there is little speed variation.

A two-shaft gas turbine is shown in Figure 3-4. In this design, the turbine section is divided into a high-pressure and low-pressure arrangement, where the high-pressure turbine is mechanically tied to the compressor section by one shaft, while the low-pressure turbine, or power turbine, has its own shaft and is connected to the external load unit. This configuration allows the high-pressure turbine/compressor shaft assembly, or rotor, to operate at or near optimum design speeds, while the power turbine rotor speed can vary over as wide a range as is required by most external-load units in mechanical drive applications (i.e., compressors and pumps).

A third configuration is a three-shaft gas turbine. As shown in Figure 3-5, the compressor section is divided into a low-pressure and high-pressure configuration. The low-pressure compressor stages are mechanically tied to the low-pressure turbine stages, and the high-pressure compressor stages are similarly connected to the high-pressure turbine stages in a concentric shaft arrangement. These low-pressure and high-pressure rotors operate at optimum design speeds independent of each other. The power turbine stages are mounted on a third independent shaft and form the power turbine rotor, the speed of

which can vary over as wide a range as is necessary for mechanical drive applications.

Gas turbines can burn a variety of fuels. Most burn natural gas, waste process gases, or liquid fuels such as distillate oils (primarily No. 2 fuel oil). Some gas turbines are capable of burning lower-grade residual or even crude oil with minimal processing. Coal-derived gases can be burned in some turbines.

The capacity of individual gas turbines ranges from approximately 0.08 to over 200 megawatts (MW) (107 to 268,000 horsepower [hp]).² Manufacturers continue to increase the horsepower of individual gas turbines, and frequently they are "ganged," or installed in groups so that the total horsepower output from one location can meet virtually any installation's power requirements.

Several characteristics of gas turbines make them attractive power sources. These characteristics include a high horsepower-to-size ratio, which allows for efficient space utilization, and a short time from order placement to on-line operation. Many suppliers offer the gas turbine, load unit, and all accessories as a fully assembled package that can be performance tested at the supplier's facility. This packaging is cost effective and saves substantial installation time. Other advantages of gas turbines are:

1. Low vibration;
2. High reliability;
3. No requirement for cooling water;
4. Suitability for remote operation;
5. Lower capital costs than reciprocating engines; and
6. Lower capital costs than boiler/steam turbine-based electric power generating plants.⁸

3.2 OPERATING CYCLES

The four basic operating cycles for gas turbines are simple, regenerative, cogeneration, and combined cycles. Each of these cycles is described separately below.

3.2.1 Simple Cycle

The simple cycle is the most basic operating cycle of a gas turbine. In a simple cycle application, a gas turbine functions with only the three primary sections described in Section 3.1, as depicted in Figure 3-6.

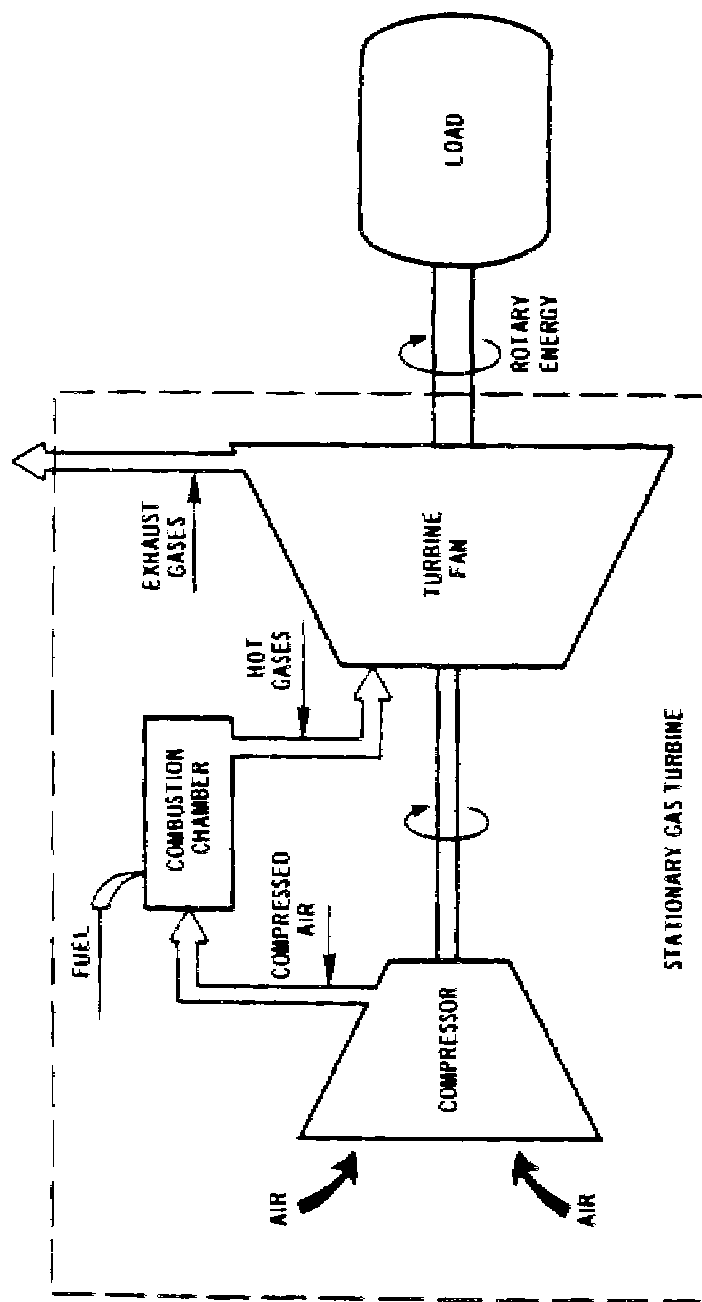


Figure 3-6. Simple cycle gas turbine application.¹⁰

¹⁰ Cycle efficiency, defined as a percentage of useful shaft energy output to fuel energy input, is typically in the 30 to 35 percent range, although one manufacturer states an efficiency of 40 percent for an engine recently introduced to the market.⁹ In addition to shaft energy output, 1 to 2 percent of the fuel input energy can be attributed to mechanical losses; the balance is exhausted from the turbine in the form of heat.⁷ Simple cycle operation is typically used when there is a requirement for shaft horsepower without recovery of the exhaust heat. This cycle offers the lowest installed capital cost but also provides the least efficient use of fuel and therefore the highest operating cost.

3.2.2 Regenerative Cycle

The regenerative cycle gas turbine is essentially a simple cycle gas turbine with an added heat exchanger, called a regenerator or recuperator, to preheat the combustion air. In the regenerative cycle, thermal energy from the exhaust gases is transferred to the compressor discharge air prior to being introduced into the combustor. A diagram of this cycle is depicted in Figure 3-7

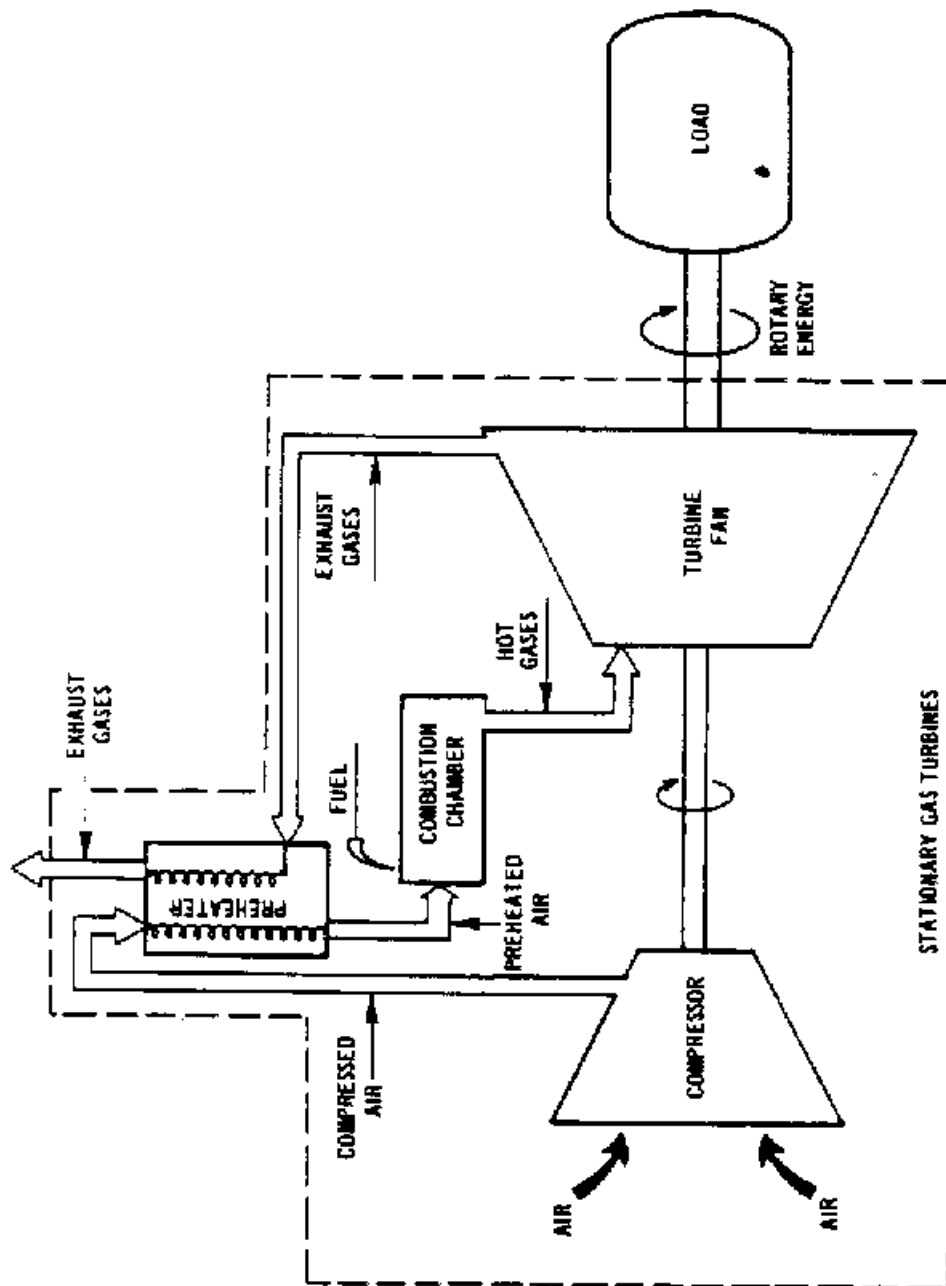


Figure 3-7. Regenerative cycle gas turbine.¹¹

.¹¹ Preheating the combustion air reduces the amount of fuel required to reach design combustor temperatures and therefore improves the overall cycle efficiency over that of simple cycle operation. The efficiency gain is directly proportional to the differential temperature between the exhaust gases and compressor discharge air. Since the compressor discharge air temperature increases with an increase in pressure ratio, higher regenerative cycle efficiency gains are realized from lower compressor pressure ratios typically found in older gas turbine models.⁷ Most new or updated gas turbine models with high compressor pressure ratios render regenerative cycle operation economically unattractive because the capital cost of the regenerator cannot be justified by the marginal fuel savings.

3.2.3 Cogeneration Cycle

A gas turbine used in a cogeneration cycle application is essentially a simple cycle gas turbine with an added exhaust heat exchanger, called a heat recovery steam generator (HRSG). This configuration is shown in Figure 3-8

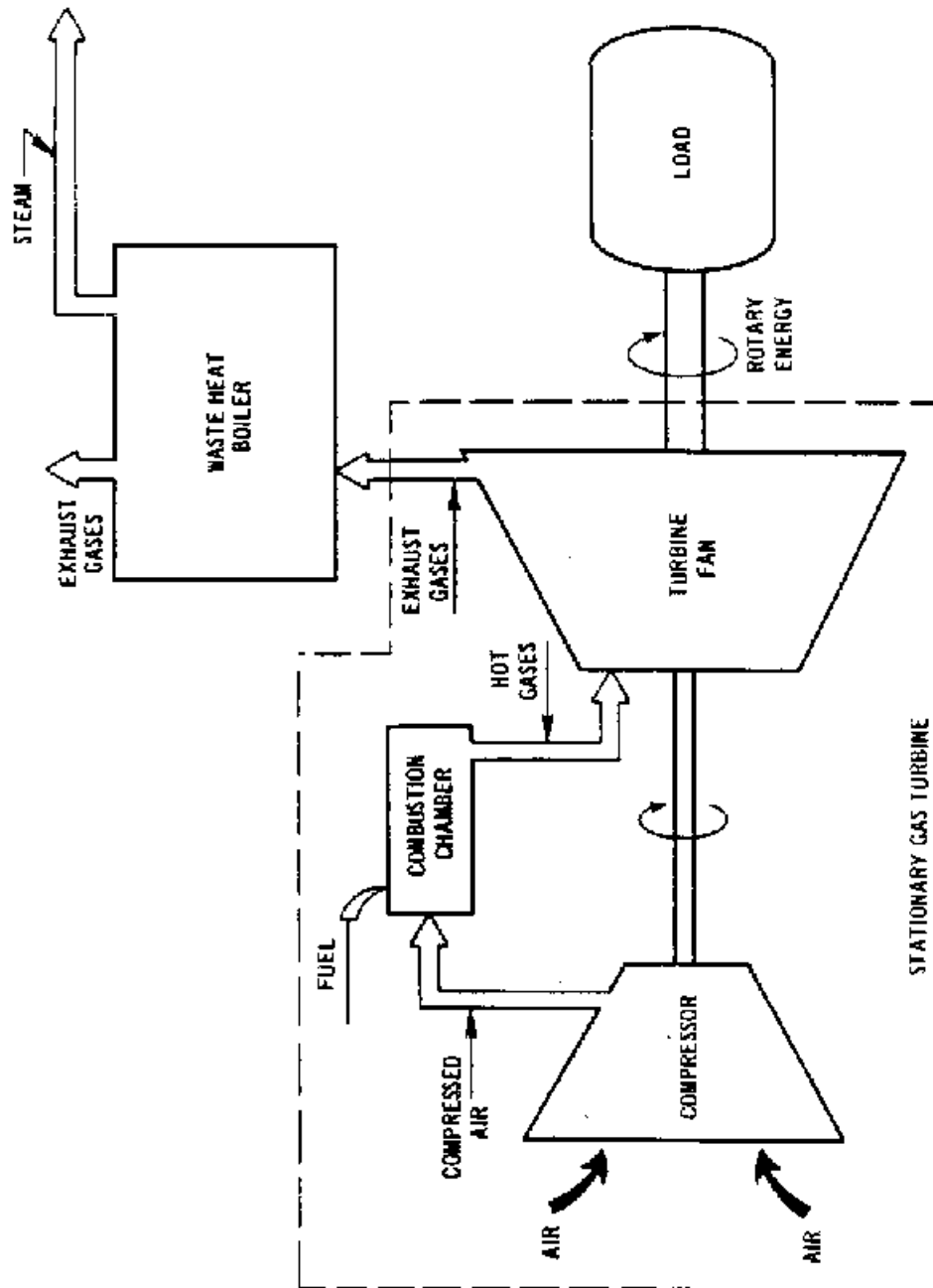


Figure 3-8. Cogeneration cycle gas turbine application.¹²

.¹² The steam generated by the exhaust heat can be delivered at a variety of pressure and temperature conditions to meet site thermal process requirements. Where the exhaust heat is not sufficient to meet site requirements, a supplementary burner, or duct burner, can be placed in the exhaust duct upstream of the HRSG to increase the exhaust heat energy. Adding the HRSG equipment increases the capital cost, but recovering the exhaust heat increases the overall cycle efficiency to as high as 75 percent.¹³

3.2.4 Combined Cycle

A combined cycle is the terminology commonly used for a gas turbine/HRSG configuration as applied at an electric utility. This cycle, shown in Figure 3-9

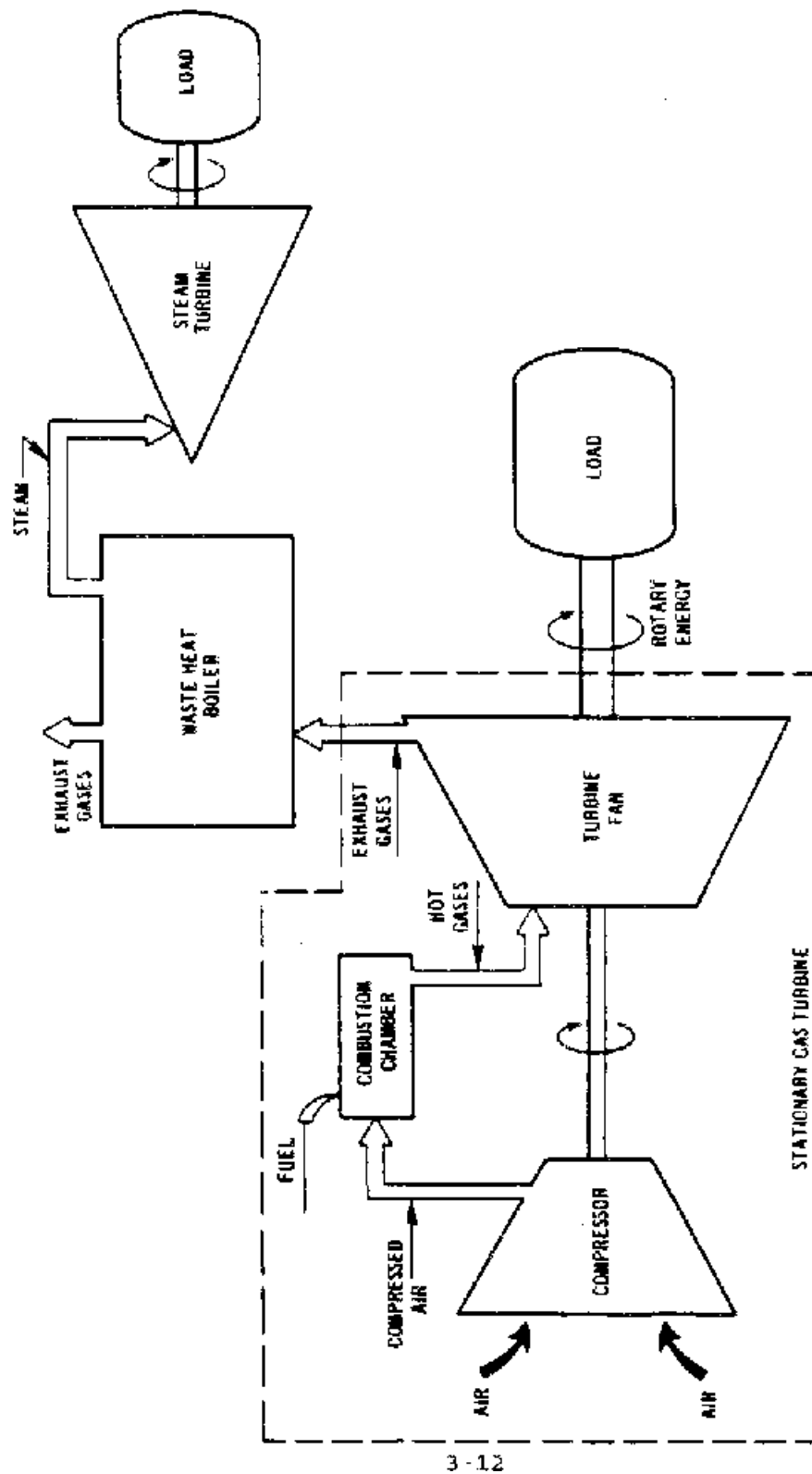


Figure 3-9. Combined cycle gas turbine application.¹²

, is used to generate electric power.¹² The gas turbine drives an electric generator, and the steam produced in the HRSG is delivered to a steam turbine, which also drives an electric generator. The boiler may be supplementary-fired to increase the steam production where desired. Cycle efficiencies can exceed 50 percent.

3.3 INDUSTRY APPLICATIONS

Gas turbines are used by industry in both mechanical and electrical drive applications. Compressors and pumps are most often the driven load unit in mechanical drive applications, and electric generators are driven in electrical drive installations. Few sites have gas/air compression or fluid pumping requirements that exceed 15 MW (20,100 hp), and for this reason mechanical drive applications generally use gas turbines in the 0.08- to 15.0-MW (107- to 20,100-hp) range.¹⁴ Electric power requirements range over the entire available range of gas turbines, however, and all sizes can be found in electrical drive applications, from 0.08 to greater than 200 MW (107 to 268,000 hp).¹⁵

The primary applications for gas turbines can be divided into five broad categories: the oil and gas industry,

stand-by/emergency electric power generation, independent electric power producers, electric utilities, and other industrial applications.¹⁶ Where a facility has a requirement for mechanical shaft power only, the installation is typically simple or regenerative cycle. For facilities where either electric power or mechanical shaft power and steam generation are required, the installation is often cogeneration or combined cycle to capitalize on these cycles' higher efficiencies.

3.3.1 Oil and Gas Industry

The bulk of mechanical drive applications are in the oil and gas industry. Gas turbines in the oil and gas industry are used primarily to provide shaft horsepower for oil and gas extraction and transmission equipment, although they are also used in downstream refinery operations. Most gas turbines found in this industry are in the 0.08- to 15.0-MW (107- to 20,100-hp) range.

Gas turbines are particularly well suited to this industry, as they can be fueled by a wide range of gaseous and liquid fuels often available at the site. Natural gas and distillate oil are the most common fuels. Many turbines can burn waste process gases, and some turbines can burn residual oils and even crude oil. In addition, gas turbines are suitable for remote installation sites and unattended operation. Most turbines used in this industry operate continuously, 8,000+ hours per year, unless the installation is a pipeline transmission application with seasonal operation.

Competition from reciprocating engines in this industry is significant. Although gas turbines have a considerable capital cost advantage, reciprocating engines require less fuel to produce the same horsepower and consequently have a lower operating cost.¹⁷ Selection of gas turbines vs. reciprocating engines is generally determined by site-specific criteria such as installed capital costs, costs for any required emissions control equipment, fuel costs and availability, annual operating hours, installation and structural considerations, compatibility with existing equipment, and operating experience.

3.3.2 Stand-By/Emergency Electric Power Generation

Small electric generator sets make up a considerable number of all gas turbine sales under 3.7 MW (5,000 hp). The majority of these installations provide backup or emergency power to critical networks or equipment and use liquid fuel. Telephone companies are a principal user, and hospitals and small municipalities also are included in this market. These turbines operate on an as-needed basis, which typically is between 75 and 200 hours per year.

Gas turbines offer reliable starting, low weight, small size, low vibration, and relatively low maintenance, which are important criteria for this application. Gas turbines in this size range have a relatively high capital cost, however, and reciprocating engines dominate this market, especially for applications under 2,000 kW (2,700 hp).^{18,19}

3.3.3 Independent Electrical Power Producers

Large industrial complexes and refining facilities consume considerable amounts of electricity, and many sites choose to generate their own power. Gas turbines can be used to drive electric generators in simple cycle operation, or an HRSG system may be added to yield a more efficient cogeneration cycle. The vast majority of cogeneration installations operate in a combined cycle capacity, using a steam turbine to provide additional electric power. The Public Utility Regulatory Policies Act (PURPA) of 1978 encourages independent cogenerators to generate electric power by requiring electric utilities to (1) purchase electricity from qualifying producers at a price equal to the cost the utility can avoid by not having to otherwise supply that power (avoided cost) and (2) provide backup power to the cogenerator at reasonable rates. Between 1980 and 1986, approximately 20,000 MW of gas turbine-produced electrical generating capacity was certified as qualifying for PURPA benefits. This installed capacity by private industry power generators is more than the sum of all utility gas turbine orders for all types of central power plants during this period.²⁰ The Department of Energy (DOE) expects an additional 27,000 MW

capacity to be purchased by private industry in the next 10 years.²¹

Gas turbines installed in this market range in power from 1 to over 100 MW (1,340 to 134,000 hp) and operate typically between 4,000 and 8,000 hours per year. While reciprocating engines compete with the gas turbine at the lower end of this market (under approximately 7.5 MW [10,000 hp]), the advantages of lower installed costs, high reliability, and low maintenance requirements make gas turbines a strong competitor.

3.3.4 Electric Utilities

Electric utilities are the largest user of gas turbines on an installed horsepower basis. They have traditionally installed these turbines for use as peaking units to meet the electric power demand peaks typically imposed by large commercial and industrial users on a daily or seasonal basis; consequently, gas turbines in this application operate less than 2,000 hours per year.²² The power range used by the utility market is 15 MW to over 150 MW (20,100 to 201,000 hp). Peaking units typically operate in simple cycle.

The demand for gas turbines from the utility market was flat through the late 1970's and 1980's as the cost of fuel increased and the supplies of gas and oil became unpredictable. There are signs, however, that the utility market is poised to again purchase considerable generating capacity. The capacity margin, which is the utility industry's measure of excess generation capacity, peaked at 30 percent in 1982. By 1990, the capacity margin had dropped to approximately 20 percent, and, based on current construction plans, will reach the industry rule-of-thumb minimum of 15 percent by 1995.²¹ The utility industry is adding new capacity and repowering existing older plants, and gas turbines are expected to play a considerable role.

Many utilities are now installing gas turbine-based combined cycle installations with provisions for burning coal-derived gas fuel at some future date. This application is known as integrated coal gasification combined cycle (IGCC). At least five power plant projects have been announced, and several more

are being negotiated. Capital costs for these plants are in many cases higher than comparable natural gas-fueled applications, but future price increases for natural gas could make IGCC an attractive option for the future.²³

Utility orders for gas turbines have doubled in each of the last 2 years. The DOE says that electric utilities will need to add an additional 73,000 MW to capacity to meet demand by the year 2000, and as Figure 3-10

US DEPARTMENT OF ENERGY FORECAST - 1990 to 2000

73000 MW TOTAL

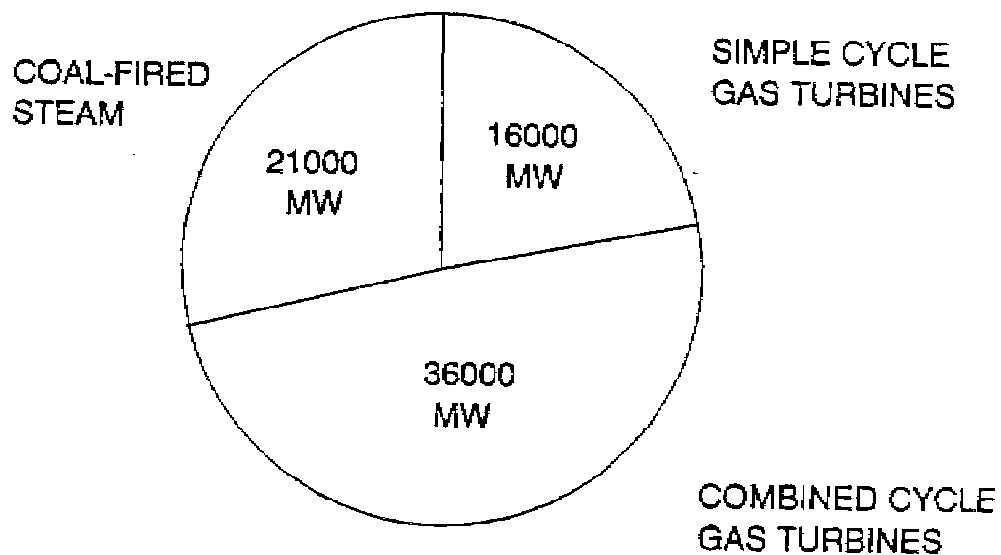
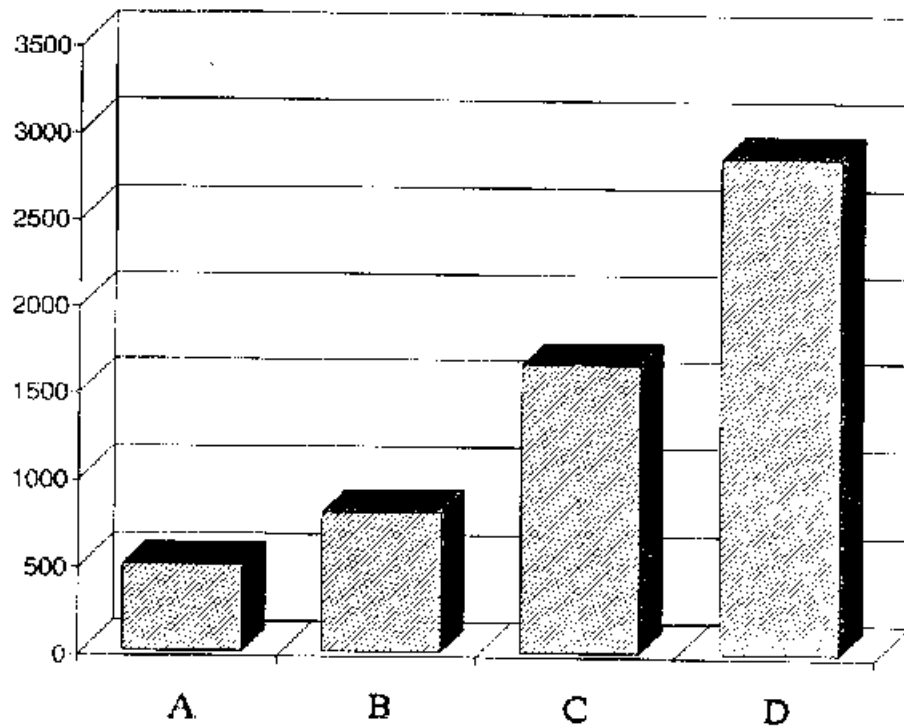


Figure 3-10. Total capacity to be purchased by the utility industry.²¹

shows, DOE expects 36,000 MW of combined cycle and 16,000 MW of simple cycle gas turbines to be purchased. This renewed interest in gas turbines is a result of:

1. The introduction of new, larger, more efficient gas turbines;
2. Lower natural gas prices and proven reserves to meet current demand levels for more than 100 years;
3. Shorter lead times than those of competing equipment; and
4. Lower capital costs for gas turbines.²¹

Utility capital cost estimates, as shown in Figure 3-11



- A - Repower existing plant using combined cycle gas turbines
- B - New plant using combined cycle gas turbines
- C - New plant using coal fired boilers
- D - New plant using nuclear power

Figure 3-11. Capital costs for electric utility plants.²⁴

, are (1) \$500 per KW for repowering existing plants with combined cycle gas turbines, (2) \$800 per KW for new combined cycle plants, (3) \$1,650 per KW for new coal-fired plants, and (4) \$2,850 per KW for new nuclear-powered plants.²⁴

Gas turbines are also an alternative to displace planned or existing nuclear facilities. A total of 1,020 MW of gas turbine-generated electric power was recently commissioned in Michigan at a plant where initial design and construction had begun for a nuclear plant. Four additional idle nuclear sites are considering switching to gas turbine-based power production due to the legal, regulatory, financial, and public obstacles facing nuclear facilities.²⁴

3.3.5 Other Industrial Applications

Industrial applications for gas turbines include various types of mechanical drive and air compression equipment. These applications peaked in the late 1960's and declined through the 1970's.²⁵ With the promulgation of PURPA in 1978 (see Section 3.3.3), many industrial facilities have found it

economically feasible to install a combined cycle gas turbine to meet power and steam requirements. Review of editions of Gas Turbine World over the last several years shows that a broad range of industries (e.g., pulp and paper, chemical, and food processing) have installed combined cycle gas turbines to meet their energy requirements.

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4.0 CHARACTERIZATION OF NO_x EMISSIONS

This section presents the principles of NO_x formation, the types of NO_x emitted (i.e., thermal NO_x, prompt NO_x, and fuel NO_x), and how they are generated in a gas turbine combustion process. Estimated NO_x emission factors for gas turbines and the bases for the estimates are also presented.

4.1 THE FORMATION OF NO_x

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of nitrogen (N₂) and oxygen (O₂) into N and O, respectively. Reactions following this dissociation result in seven known oxides of nitrogen: NO, NO₂, NO₃, N₂O, N₂O₃, N₂O₄, and N₂O₅. Of these, nitric oxide (NO) and nitrogen dioxide (NO₂) are formed in sufficient quantities to be significant in atmospheric pollution.¹ In this document, "NO_x" refers to either or both of these gaseous oxides of nitrogen.

Virtually all NO_x emissions originate as NO. This NO is further oxidized in the exhaust system or later in the atmosphere to form the more stable NO₂ molecule.² There are two mechanisms by which NO_x is formed in turbine combustors: (1) the oxidation of atmospheric nitrogen found in the combustion air (thermal NO_x and prompt NO_x) and (2) the conversion of nitrogen chemically bound in the fuel (fuel NO_x). These mechanisms are discussed below.

4.1.1 Formation of Thermal and Prompt NO_x

Thermal NO_x is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form oxides of nitrogen.

The major contributing chemical reactions are known as the Zeldovich mechanism and take place in the high temperature area of the gas turbine combustor.³ Simply stated, the Zeldovich mechanism postulates that thermal NO_x formation increases exponentially with increases in temperature and linearly with increases in residence time.⁴

Flame temperature is dependent upon the equivalence ratio, which is the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.⁵ An equivalence ratio of 1.0 corresponds to the stoichiometric ratio and is the point at which a flame burns at its highest theoretical temperature.⁵ Figure 4-1

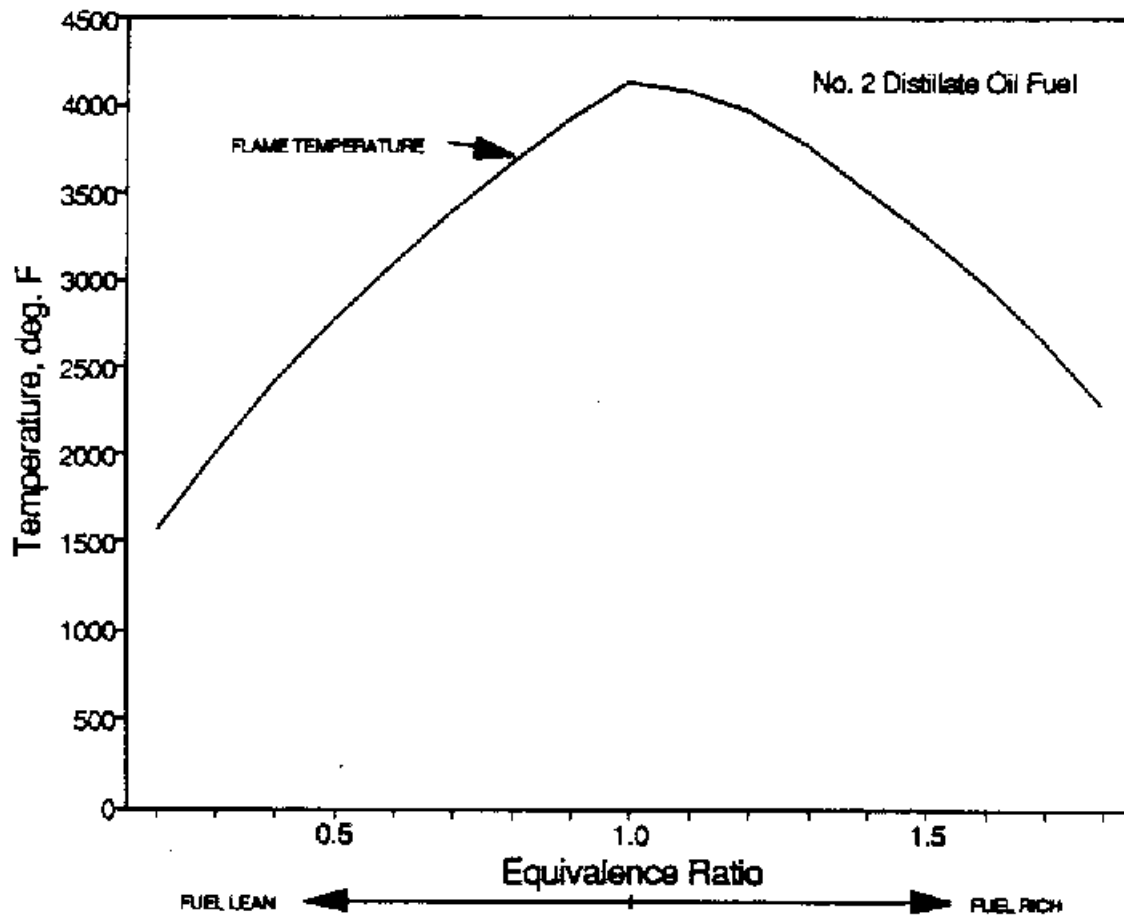
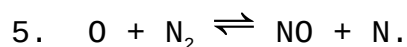
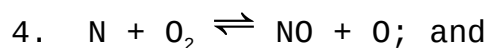
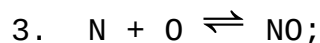
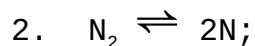
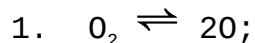


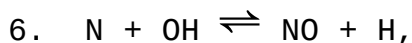
Figure 4-1. Influence of equivalence ratio on flame temperature.⁴

shows the flame temperature and equivalence ratio relationship for combustion using No. 2 distillate fuel oil (DF-2).⁴

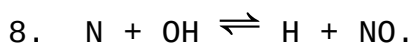
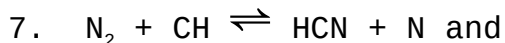
The series of chemical reactions that form thermal NO_x according to the Zeldovich mechanism are presented below.³



This series of equations applies to a fuel-lean combustion process. Combustion is said to be fuel-lean when there is excess oxygen available (equivalence ratio <1.0). Conversely, combustion is fuel-rich if insufficient oxygen is present to burn all of the available fuel (equivalence ratio >1.0). Additional equations have been developed that apply to fuel-rich combustion. These equations are an expansion of the above series to add an intermediate hydroxide molecule (OH):³

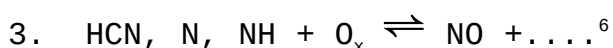
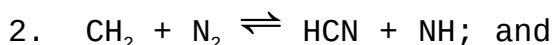
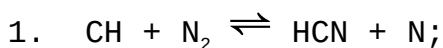


and further to include an intermediate product, hydrogen cyanide (HCN), in the formation process:³



The overall equivalence ratio for gases exiting the gas turbine combustor is less than 1.0.⁴ Fuel-rich areas do exist in the overall fuel-lean environment, however, due to less-than-ideal fuel/air mixing prior to combustion. This being the case, the above equations for both fuel-lean and fuel-rich combustion apply for thermal NO_x formation in gas turbines.

Prompt NO_x is formed in the proximity of the flame front as intermediate combustion products such as HCN, N, and NH are oxidized to form NO_x as shown in the following equations:



Prompt NO_x is formed in both fuel-rich flame zones and fuel-lean premixed combustion zones. The contribution of prompt NO_x to overall NO_x emissions is relatively small in conventional near-stoichiometric combustors, but this contribution increases with decreases in the equivalence ratio (fuel-lean mixtures). For this reason, prompt NO_x becomes an important consideration for the low-NO_x combustor designs described in Chapter 5 and establishes a minimum NO_x level attainable in lean mixtures.⁷

4.1.2 Formation of Fuel NO_x

Fuel NO_x (also known as organic NO_x) is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as

N₂ in some natural gas, does not contribute significantly to fuel NO_x formation.⁸ However, nitrogen compounds are present in coal and petroleum fuels as pyridine-like (C₅H₅N) structures that tend to concentrate in the heavy resin and asphalt fractions upon distillation. Some low-British thermal unit (Btu) synthetic fuels contain nitrogen in the form of ammonia (NH₃), and other low-Btu fuels such as sewage and process waste-stream gases also contain nitrogen. When these fuels are burned, the nitrogen bonds break and some of the resulting free nitrogen oxidizes to form NO_x.⁹ With excess air, the degree of fuel NO_x formation is primarily a function of the nitrogen content in the fuel. The fraction of fuel-bound nitrogen (FBN) converted to fuel NO_x decreases with increasing nitrogen content, although the absolute magnitude of fuel NO_x increases. For example, a fuel with 0.01 percent nitrogen may have 100 percent of its FBN converted to fuel NO_x, whereas a fuel with a 1.0 percent FBN may have only a 40 percent fuel NO_x conversion rate. The low-percentage FBN fuel has a 100 percent conversion rate, but its overall NO_x emission level would be lower than that of the high-percentage FBN fuel with a 40 percent conversion rate.¹⁰

Nitrogen content varies from 0.1 to 0.5 percent in most residual oils and from 0.5 to 2 percent for most U.S. coals.¹¹ Traditionally, most light distillate oils have had less than 0.015 percent nitrogen content by weight. However, today many distillate oils are produced from poorer-quality crudes, especially in the northeastern United States, and these distillate oils may contain percentages of nitrogen exceeding the 0.015 threshold; this higher nitrogen content can increase fuel NO_x formation.⁴ At least one gas turbine installation burning coal-derived fuel is in commercial operation in the United States.¹²

Most gas turbines that operate in a continuous duty cycle are fueled by natural gas that typically contains little or no FBN. As a result, when compared to thermal NO_x, fuel NO_x is not

currently a major contributor to overall NO_x emissions from stationary gas turbines.

4.2 UNCONTROLLED NO_x EMISSIONS

The NO_x emissions from gas turbines are generated entirely in the combustor section and are released into the atmosphere via the stack. In the case of simple and regenerative cycle operation, the combustor is the only source of NO_x emissions. In cogeneration and combined cycle applications, a duct burner may be placed in the exhaust ducting between the gas turbine and the heat recovery steam generator (HRSG); this burner also generates NO_x emissions. (Gas turbine operating cycles are discussed in Section 3.2.) The amount of NO_x formed in the combustion zone is "frozen" at this level regardless of any temperature reductions that occur at the downstream end of the combustor and is released to the atmosphere at this level.¹

4.2.1 Parameters Influencing Uncontrolled NO_x Emissions

The level of NO_x formation in a gas turbine, and hence the NO_x emissions, is unique (by design factors) to each gas turbine model and operating mode. The primary factors that determine the amount of NO_x generated are the combustor design, the types of fuel being burned, ambient conditions, operating cycles, and the power output level as a percentage of the rated full power output of the turbine. These factors are discussed below.

4.2.1.1 Combustor Design. The design of the combustor is the most important factor influencing the formation of NO_x. Design considerations are presented here and discussed further in Chapter 5.

Thermal NO_x formation, as discussed in Section 4.1.1, is influenced primarily by flame temperature and residence time. Design parameters controlling equivalence ratios and the introduction of cooling air into the combustor strongly influence thermal NO_x formation. The extent of fuel/air mixing prior to combustion also affects NO_x formation. Simultaneous mixing and combustion results in localized fuel-rich zones that yield high flame temperatures in which substantial thermal NO_x production

takes place.¹³ The dependence of thermal NO_x formation on flame temperature and equivalence ratio is shown in Figure 4-2

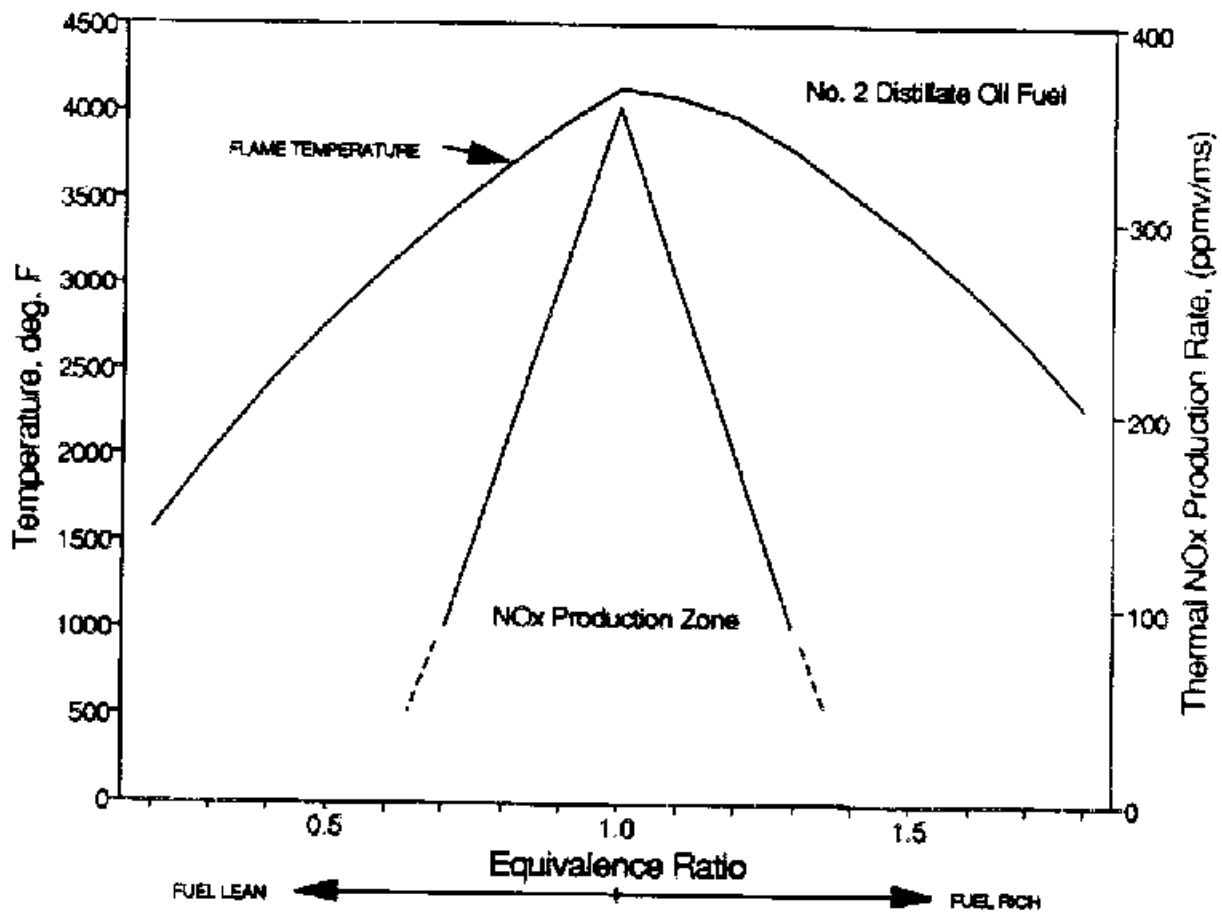


Figure 4-2. Thermal NO_x production as a function of flame temperature and equivalence ratio.⁴

for DF-2.⁴ Conversely, prompt NO_x is largely insensitive to changes in temperature and pressure.⁷

Fuel NO_x formation, as discussed in Section 4.1.2, is formed when FBN is released during combustion and oxidizes to form NO_x . Design parameters that control equivalence ratio and residence time influence fuel NO_x formation.¹⁴

4.2.1.2 Type of Fuel. The level of NO_x emissions varies for different fuels. In the case of thermal NO_x , this level increases with flame temperature. For gaseous fuels, the constituents in the gas can significantly affect NO_x emissions levels. Gaseous fuel mixtures containing hydrocarbons with molecular weights higher than that of methane (e.g., ethane, propane, and butane) burn at higher flame temperatures and as a result can increase NO_x emissions greater than 50 percent over NO_x levels for methane gas fuel. Refinery gases and some unprocessed field gases contain significant levels of these higher molecular weight hydrocarbons. Conversely, gas fuels that contain significant inert gases, such as CO_2 , generally produce lower NO_x emissions. These inert gases serve to absorb heat during combustion, thereby lowering flame temperatures and reducing NO_x emissions. Examples of this type of gas fuel are air-blown gasifier fuels and some field gases.¹⁵ Combustion of hydrogen also results in high flame temperatures, and gases with significant hydrogen content produce relatively high NO_x emissions. Refinery gases can have hydrogen contents exceeding 50 percent.¹⁶

As is shown in Figure 4-3

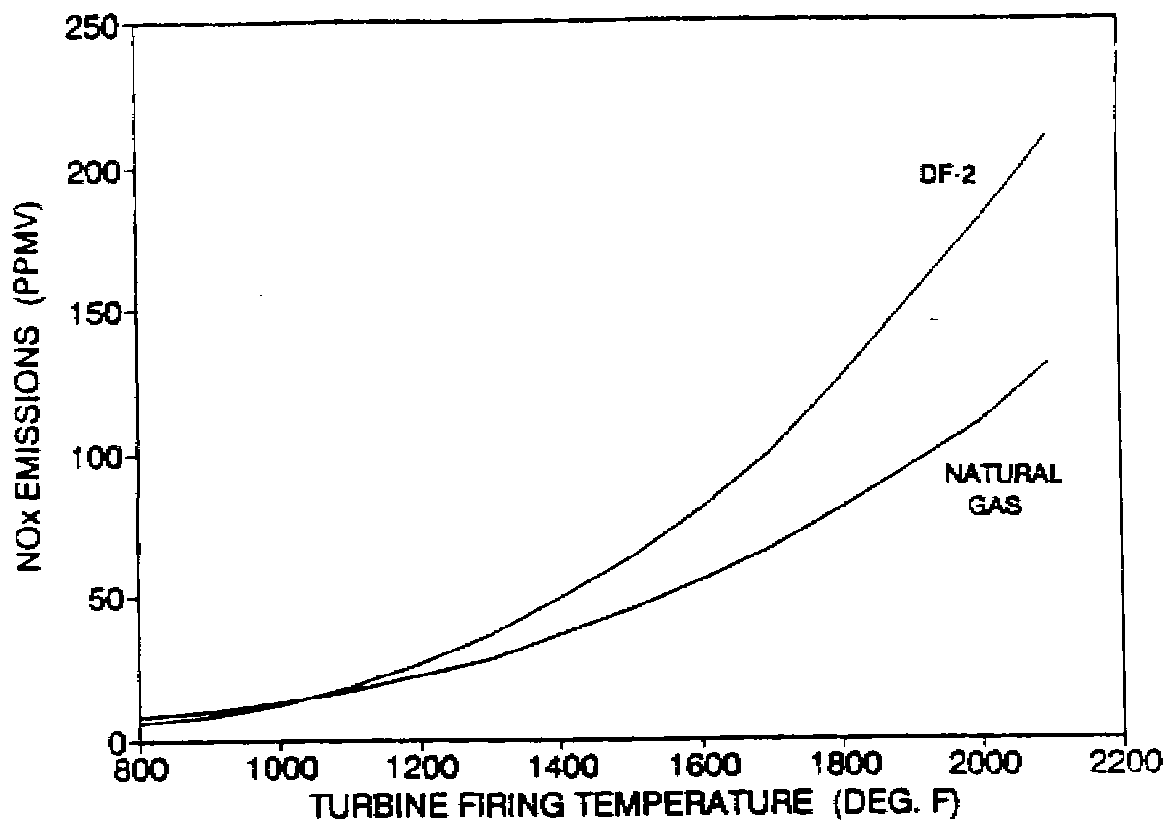


Figure 4-3. Influence of firing temperature on thermal NO_x formation.¹⁷

, DF-2 burns at a flame temperature that is approximately 75°C (100°F) higher than that of natural gas, and as a result, NO_x emissions are higher when burning DF-2 than they are when burning natural gas.¹⁷ Low-Btu fuels such as coal gas burn with lower flame temperatures, which result in

substantially lower thermal NO_x emissions than natural gas or DF-2.¹⁸ For fuels containing FBN, the fuel NO_x production increases with increasing levels of FBN.

4.2.1.3 Ambient Conditions. Ambient conditions that affect NO_x formation are humidity, temperature, and pressure. Of these ambient conditions, humidity has the greatest effect on NO_x formation.¹⁹ The energy required to heat the airborne water vapor has a quenching effect on combustion temperatures, which reduces thermal NO_x formation. At low humidity levels, NO_x emissions increase with increases in ambient temperature. At high humidity levels, the effect of changes in ambient temperature on NO_x formation varies. At high humidity levels and low ambient temperatures, NO_x emissions increase with increasing temperature. Conversely, at high humidity levels and ambient temperatures above 10°C (50°F), NO_x emissions decrease with increasing temperature.

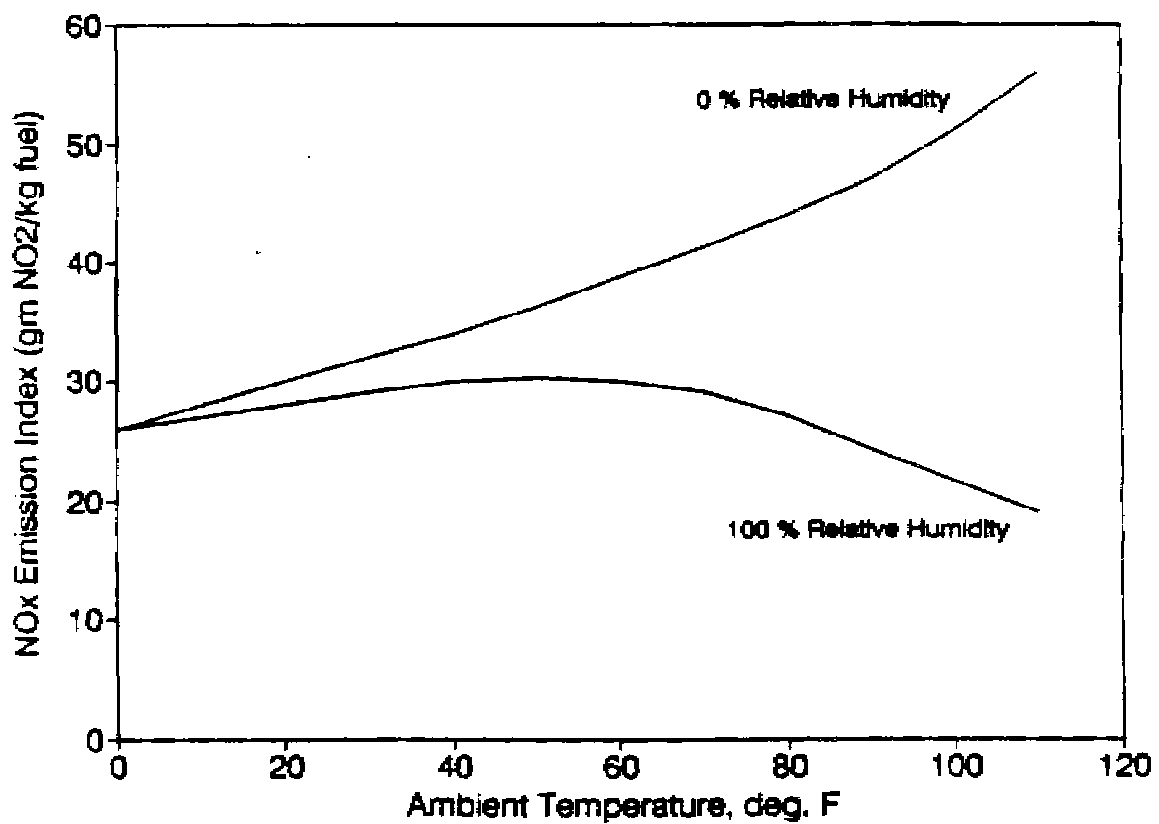


Figure 4-4. Influence of relative humidity and ambient temperature on NO_x formation.¹⁹

This effect of humidity and temperature on NO_x formation is shown in Figure 4-4. A rise in ambient pressure results in higher pressure and temperature levels entering the combustor and so NO_x production levels increase with increases in ambient pressure.¹⁹

The influence of ambient conditions on measured NO_x emission levels can be corrected using the following equation:²⁰

$$NO_x = (NO_{x0})(P_r/P_o)^{0.5} e^{19(H_0 - 0.00633)} (288^\circ K/T_a)^{1.53}$$

where:

NO_x = emission rate of NO_x at 15 percent O₂ and International Standards Organization (ISO) ambient conditions, volume percent;

NO_{x0} = observed NO_x concentration, parts per million by volume (ppmv) referenced to 15 percent O₂;

P_r = reference compressor inlet absolute pressure at 101.3 kilopascals ambient pressure, millimeters mercury (mm Hg);

P_o = observed compressor inlet absolute pressure at test, mm Hg;

H_0 = observed humidity of ambient air, g H_2O /g air;

e = transcendental constant, 2.718; and

T_a = ambient temperature, K.

At least two manufacturers state that this equation does not accurately correct NO_x emissions for their turbine models.^{8,12}

It is expected that these turbine manufacturers could provide corrections to this equation that would more accurately correct NO_x emissions for the effects of ambient conditions based on test data for their turbine models.

4.2.1.4 Operating Cycles. Emissions from identical turbines used in simple and cogeneration cycles have similar NO_x emissions levels, provided no duct burner is used in heat recovery applications. The NO_x emissions are similar because, as stated in Section 4.2, NO_x is formed only in the turbine combustor and remains at this level regardless of downstream temperature reductions. A turbine operated in a regenerative cycle produces higher NO_x levels, however, due to increased combustor inlet temperatures present in regenerative cycle applications.²¹

4.2.1.5 Power Output Level. The power output level of a gas turbine is directly related to the firing temperature, which is directly related to flame temperature. Each gas turbine has a base-rated power level and corresponding NO_x level. At power outputs below this base-rated level, the flame temperature is lower, so NO_x emissions are lower. Conversely, at peak power outputs above the base rating, NO_x emissions are higher due to higher flame temperature. The NO_x emissions for a range of firing temperatures are shown in Figure 4-3 for one manufacturer's gas turbine.¹⁷

4.2.2 NO_x Emissions From Duct Burners

In some cogeneration and combined cycle applications, the exhaust heat from the gas turbine is not sufficient to produce the desired quantity of steam from the HRSG, and a supplemental burner, or duct burner, is placed in the exhaust duct between the gas turbine and HRSG to increase temperatures to sufficient

levels. In addition to providing additional steam capacity, this burner also increases the overall system efficiency since essentially all energy added by the duct burner can be recovered in the HRSG.²²

The level of NO_x produced by a duct burner is approximately 0.1 pound per million Btu (lb/MMBtu) of fuel burned. The ppmv level depends upon the flowrate of gas turbine exhaust gases in which the duct burner is operating and thus varies with the size of the turbine.²³

Typical NO_x production levels added by a duct burner operating on natural gas fuel are:²³

Gas turbine output, megawatts (MW)	Duct burner NO _x , ppmv, referenced to 15 percent O ₂
3 to 50	10 to 30
50+	5 to 10

4.3 UNCONTROLLED EMISSION FACTORS

TABLE 4-1. UNCONTROLLED NO_x EMISSIONS FACTORS FOR GAS TURBINES AND DUCT BURNERS^{8, 12, 15, 24-29}

Manufacturer	Model No.	Output, MW	NO _x emissions, ppmv, dry and corrected to 15% O ₂		NO _x emissions factor, lb NO _x /MMBtu ^a	
			Natural gas	Distillate oil No. 2	Natural gas	Distillate oil No. 2
Solar	Saturn	1.1	99	150	0.397	0.551
	Centaur	3.3	130	179	0.521	0.658
	Centaur "H"	4.0	105	160	0.421	0.588
	Taurus	4.5	114	168	0.457	0.618
	Mars T12000	8.8	178	267	0.714	0.981
	Mars T14000	10.0	199	NA ^b	0.798	NA ^b
GM/Allison	501-KB5	4.0	155	231	0.622	0.849
	570-KA	4.9	101	182	0.405	0.669
	571-KA	5.9	101	182	0.405	0.669
General Electric	LM1600	12.8	144	237	0.577	0.871
	LM2500	21.8	174	345	0.698	1.27
	LM5000	33.1	185	364	0.742	1.34
	LM6000	41.5	220	417	0.882	1.53
	MS5001P	26.3	142	211	0.569	0.776
	MS6001B	38.3	148	267	0.593	0.981
	MS7001EA	83.5	154	228	0.618	0.838
	MS7001F	123	179	277	0.718	1.02
	MS9001EA	150	176	235	0.706	0.864
	MS9001F	212	176	272	0.706	1.00
Asea Brown Boveri	GT8	47.4	430	680	1.72	2.50
	GT10	22.6	150	200	0.601	0.735
	GT11N	81.6	390	560	1.56	2.06
	GT35	16.9	300	360	1.20	1.32
Westinghouse	W261B11/12	52.3	220	355	0.882	1.31
	W501D5	119	190	250	0.762	0.919
Siemens	V84.2	105	212	360	0.850	1.32
	V94.2	153	212	360	0.850	1.32
	V64.3	61.5	380	530	1.52	1.95
	V84.3	141	380	530	1.52	1.95
	V94.3	203	380	530	1.52	1.95
Duct burners	All	NA ^c	<30	NA ^b	<0.100 ^d	NA ^b

^aBased on emission levels provided by gas turbine manufacturers, corresponding to rated load at ISO conditions.

NO_x emissions calculations are shown in Appendix A.

^bNot available.

^cNot applicable.

^dReferences 16 and 22.

Uncontrolled emission factors are presented in Table 4-1. These factors are based on uncontrolled emission levels provided by manufacturers in ppmv, dry, and corrected to 15 percent O₂, corresponding to 100 percent output load and International Standards Organization (ISO) conditions of 15°C (59°F) and 1 atmosphere (14.7 psia). Sample calculations are given in Appendix A. The uncontrolled emissions factors range from 0.397 to 1.72 lb/MMBtu (99 to 430 ppmv) for natural gas and 0.551 to 2.50 lb/MMBtu (150 to 680 ppmv) for DF-2.

4.4 REFERENCES FOR CHAPTER 4

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5.0 NO_x CONTROL TECHNIQUES

Nationwide NO_x emission limits have been established for stationary gas turbines in the new source performance standards (NSPS) promulgated in 1979.¹ This standard, summarized in Table 5-1

**TABLE 5-1. NO_x EMISSION LIMITS AS ESTABLISHED BY THE NEW
SOURCE PERFORMANCE STANDARDS FOR GAS TURBINES¹**

Fuel input MMBtu/hr	Size, MW	Application(s)	NO _x limit, ppmv at 15% O ₂ , dry ^{a b}
<10	1 ^c	All	None
10-100	1-10 ^c	All	150
>100	10+ ^c <30 ^c >30 ^c	Utility ^d Nonutility Nonutility	75 150 None
<100	10 ^c	Regenerative cycle	None
All	All	e	None

^aBased on thermal efficiency of 25 percent. This limit may be increased for higher efficiencies by multiplying the limit in the table by 14.4/actual heat rate, in kJ/watt-hr.

^bA fuel-bound nitrogen allowance may be added to the limits listed in the table according to the table listed below:

<u>Fuel-bound nitrogen (N), percent by weight</u>	<u>Allowable increase, ppmv</u>
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	$400 \times N$
$0.1 < N \leq 0.25$	$40 + [6.7 \times (N - 0.1)]$
$N > 0.25$	50

^cBased on gas turbine heat rate of 10,000 Btu/kW-hr.

^dAn installation is considered a utility if more than 1/3 of its potential electrical output is sold.

^eEmergency/stand-by, military (except garrison facilities), military training, research and development, firefighting, and emergency fuel operation applications are exempt from NO_x emission limits.

, effectively sets a limit for new, modified, or reconstructed gas turbines greater than 10.7 gigajoules per hour (approximately 3,800 horsepower [hp]) of 75 or 150 parts per million by volume (ppmv), corrected to 15 percent oxygen (O₂) on a dry basis, depending upon the size and application of the turbine. State and regional regulatory agencies may set more restrictive limits, and two organizations have established limits as low as 9 ppmv: the South Coast Air Quality Management District (SCAQMD) has defined limits as listed in Table 5-2

TABLE 5-2. NO_x COMPLIANCE LIMITS AS ESTABLISHED BY THE SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT (SCAQMD) FOR EXISTING TURBINES. RULE 1134. ADOPTED AUGUST 1989.^{a,2}

Unit size, megawatt rating (MW)	NO _x limit, ppmv, 15% O ₂ dry ^b
0.3 to <2.9 MW	25
2.9 to <10.0 MW	9
2.9 to <10.0 MW No SCR	15
10.0 MW and over	9
10.0 MW and over No SCR	12
60 MW and over Combined cycle No SCR	15
60 MW and over Combined cycle	9
Compliance limit = Reference limit X EFF/25 percent	
where:	
$EFF = \frac{\text{Actual heat rate at HHV of fuel (Btu/kW-hr)}}{3,413} \times 100\%$	
or	
$EFF^c = (\text{Manufacturer's rated efficiency at LHV}) \times \frac{LHV}{HHV}$	

^aThe NO_x reference limits to be effective by December 31, 1995.

^bAveraged over 15 consecutive minutes.

^cEFF = the demonstrated percent efficiency of the gas turbine only as calculated without consideration of any down-stream energy recovery from the actual heat rate (Btu/kW-hr), or 1.34 (Btu/hp-hr); corrected to the higher heating value (HHV) of the fuel and ISO conditions, as measured at peak load for that facility; or the manufacturer's continuous rated percent efficiency (manufacturer's rated efficiency) of the gas turbine after correction from lower heating value (LHV) to the HHV of the fuel, whichever efficiency is higher. The value of EFF shall not be less than 25 percent. Gas turbines with lower efficiencies will be assigned a 25 percent efficiency for this calculation.

; and the Northeast States for Coordinated Air Use Management (NЕСAUM) has recommended limits as listed in Table 5-3.

TABLE 5-3. NO_x EMISSION LIMITS RECOMMENDED BY THE NORTHEAST STATES FOR COORDINATED AIR USE MANAGEMENT (NESCAUM)

NEW TURBINES³

Fuel input, MMBtu/hr	Size, MW ^a	Fuel type	NO _x limit, ppmv ^b
1-100	1-10	Gas Oil	42 65
>100	10+	Gas Oil Gas/oil back-up	9 ^c 9 ^c 9 ^c /18 ^{c d}

^aBased on gas turbine heat rate of 10,000 Btu/kw-hr.

^bDry basis, corrected to 15 percent oxygen.

^cBased on use of selective catalytic reduction (SCR). Limits for operation without SCR, where permitted, should be the turbine manufacturer's lowest guaranteed NO_x limit.

^dBased on the use of SCR and a fuel-bound nitrogen content of 600 ppm or less.

EXISTING TURBINES⁴

Operating cycle	Fuel	NO _x emission limit, ppmv, 15 percent O ₂
Simple	Gas, no oil back-up	55
	Oil	75
	Gas, with oil back-up	55 (Gas fuel) 75 (Oil fuel)
Combined	Gas, no oil back-up	42
	Oil	65
	Gas, with oil back-up	42 (Gas fuel) 65 (Oil fuel)

Note: Applies to existing turbines rated at 25 MMBtu/hr or above (maximum heat input rate).

This chapter discusses the control techniques that are available to reduce NO_x emissions for stationary turbines, the use of duct burners, the use of alternate fuels to lower NO_x emissions, and the applicability of NO_x control techniques to offshore applications. Each control technique is structured into categories to discuss the process description, applicability, factors that affect performance, and achievable controlled NO_x emission levels. Where information for a technique is limited, one or more categories may be combined. Section 5.1 describes wet controls, including water and steam injection. Section 5.2 describes combustion controls, including lean and staged combustion. Selective catalytic reduction (SCR), a postcombustion technique, is described in Section 5.3, and the combination of SCR with other control techniques is described in

Section 5.4. Emissions from duct burners and their impact on total NO_x emissions are described in Section 5.5. Section 5.6 describes NO_x emission impacts when using alternate fuels. Two control techniques that show potential for future use, selective noncatalytic reduction (SNCR) and catalytic combustion, are described in Sections 5.7 and 5.8, respectively. Control technologies for offshore oil platforms are described in Section 5.9. Finally, references for Chapter 5 are found in Section 5.10.

5.1 WET CONTROLS

The injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_x formation. This control technique is available from all gas turbine manufacturers contacted for this study.⁵⁻¹¹

The process description, applicability, factors affecting performance, emissions data and manufacturers' guarantees, impacts on other emissions, and gas turbine performance and maintenance impacts are discussed in this section.

5.1.1 Process Description

Injecting water into the flame area of a turbine combustor provides a heat sink that lowers the flame temperature and thereby reduces thermal NO_x formation. Injection rates for both water and steam are usually described by a water-to-fuel ratio (WFR) and are usually given on a weight basis (e.g., lb water to lb fuel).

A water injection system consists of a water treatment system, pump(s), water metering valves and instrumentation, turbine-mounted injection nozzles, and the necessary interconnecting piping. Water purity is essential to prevent or mitigate erosion and/or the formation of deposits in the hot section of the turbine; Table 5-4

TABLE 5-4. WATER QUALITY SPECIFICATIONS OF SELECTED GAS TURBINE MANUFACTURERS FOR WATER INJECTION SYSTEMS¹¹⁻¹⁸

Turbine Manufacturer								
Element	A	B	C	D	E	F	G	H
Total solids, ppm (dissolved and nondissolved)	5	5	1	a	0.1 gram/gallon	15	5	8
Total alkali metals, ppm	0.1	0.5 (HD) 0.1 (AD) ^d	0.1	--	0.5	0.15	≤0.05	--
Calcium, ppm	5	--	--	--	--	--	<1.0	--
Sulfates, ppm	--	--	--	--	--	--	--	0.5
Silica, ppm	0.02	--	0.02	--	--	0.1	<0.02	0.1
Silicon, ppm	--	--	--	18.0	--	--	--	--
Sulfur, ppm	0.1	--	--	--	--	1.0	--	--
Chlorides, ppm	--	--	--	6.0	--	1.0	--	0.5
Iron and copper, ppm	--	--	--	0.1	--	--	--	--
Sodium and potassium, ppm	--	--	--	--	--	--	--	0.1
Particle size, microns	10	--	10	--	5	--	--	20
Total hardness, ppm	--	--	--	--	--	0.2	--	--
Oxygen ^f	--	--	--	--	--	--	--	--
Acidity, pH	7.0-8.5	6.5-7.5	7.0-8.5	7.5-8.0	--	6.5-7.5	6.5-7.0	6.0-8.0

^aDetermined by local regulations for particulates exhausted from combustion process.

^bHD - heavy-duty turbine.

^cIncluding vanadium and lead.

^dAD - aeroderivative turbine.

^e90 percent of 0.1 gram particles shall be less than 5 microns.

summarizes the water quality specifications for eight gas turbine manufacturers.

In a steam injection system, steam replaces water as the injected fluid. The injection system is similar to that for water injection, but the pump is replaced by a steam-producing boiler. This boiler is usually a heat recovery steam generator

(HRSG) that recovers the gas turbine exhaust heat and generates steam. The balance of the steam system is similar to the water injection system. The water treatment required for boiler feed water to the HRSG yields a steam quality that is suitable for injection into the turbine. The additional steam requirement for NO_x control, however, may require that additional capacity be added to the boiler feed water treatment system.

Another technique that is commercially available for oil-fired aeroderivative and industrial turbines uses a water-in-oil emulsion to reduce NO_x emissions. This technique introduces water into the combustion process by emulsifying water in the fuel oil prior to injection. This emulsion has a water content of 20 to 50 percent by volume and is finely dispersed and chemically stabilized in the oil phase. The principle of NO_x control is similar to conventional water injection, but the uniform dispersion of the water in the oil provides greater NO_x reduction than conventional water injection at similar WFR's.¹⁹

A water-in-oil emulsion injection system consists of mechanical emulsification equipment, chemical stabilizer injection equipment, water metering valves, chemical storage and metering valves, and instrumentation. In most cases the emulsifying system can be retrofitted to the existing fuel delivery system, which eliminates the requirement for a separate delivery system for water injection. At multiunit installations, one emulsion system can be used to supply emulsified fuel to several turbines. For dual fuel turbines, the emulsion can be injected through the oil fuel system to control NO_x emissions.¹⁹

Data provided by the vendor for this technique indicates that testing has been performed on oil-fired turbines operating in peaking duty. Long-term testing has not been completed at this point to quantify the long-term effects of the emulsifier on the operation and maintenance of the turbine.

5.1.2 Applicability of Wet Controls

Wet controls have been applied effectively to both aeroderivative and heavy-duty gas turbines and to all configurations except regenerative cycle applications.²⁰ It is expected that wet controls can be used with regenerative cycle turbines, but no such installations were identified. All manufacturers contacted have water injection control systems available for their gas turbine models; many also offer steam injection control systems. Where both systems are available, the decision of which control to use depends upon steam availability and economic factors specific to each site.

Wet controls can be added as a retrofit to most gas turbine installations. In the case of water injection, one limitation is the possible unavailability of injection nozzles for turbines operating in dual fuel applications. In this application, the injection nozzle as designed by the manufacturer may not physically accommodate a third injection port for water injection. This limitation also applies to steam injection. In addition, steam injection is not an available control option from some gas turbine manufacturers.

5.1.3 Factors Affecting the Performance of Wet Controls

The WFR is the most important factor affecting the performance of wet controls. Other factors affecting performance are the combustor geometry and injection nozzle(s) design and the fuel-bound nitrogen (FBN) content. These factors are discussed below.

The WFR has a significant impact on NO_x emissions. Tables 5-5 and 5-6 provide NO_x reduction and WFRs for natural gas and

**TABLE 5-5. MANUFACTURER'S GUARANTEED NO_x REDUCTION EFFICIENCIES
AND ESTIMATED WATER-TO-FUEL RATIOS FOR NATURAL
GAS FUEL OPERATION^{5-11, 21-24}**

Manufacturer/model	NO _x emission levels, ppmv at 15% O ₂ /NO _x percent reduction			Water-to-fuel ratio (lb water to lb fuel)	
	Uncontrolled	Water injection	Steam injection	Water injection	Steam injection
General Electric					
LM1600	133	42 ^a /68	25/81	0.61	1.49
LM2500	174	42 ^a /76	25/86	0.73	1.46
LM5000	185	42 ^a /77	25/87	0.63	1.67
LM6000	220	42 ^a /81	25/89	0.68	1.67
MS5001P	142	42/70	42/70	0.72	1.08
MS6001B	148	42/72	42/72	0.77	1.16
MS7001E	154	42/73	42/73	0.81	1.22
MS7001F	210	42/80	42/80	0.79	1.34
MS9001E	161	42/74	42/74	0.78	1.18
MS9001F	210	42/86	42/80	NA ^b	NA ^b
Asea Brown Boveri					
GT10	150	25/83	42/72	0.93	1.07
GT8	430	25/94	29/93	1.86	2.48
GT11N	390	25/94	25/94	1.76	2.47
GT35	300	42/86	60/80	1.00	1.20
Solar Turbines, Inc.					
T-1500 Saturn	99	42/58	NA ^c /NA ^c	0.33	NA ^c
T-4500 Centaur	130	42/68	NA ^c /NA ^c	0.61	NA ^c
Type H Centaur	105	42/60	NA ^c /NA ^c	0.70	NA ^c
Taurus	114	42/63	NA ^c /NA ^c	0.79	NA ^c
T-12000 Mars	178	42/76	NA ^c /NA ^c	0.91	NA ^c
T-14000 Mars	199	42/79	NA ^c /NA ^c	1.14	NA ^c
Allison/GM					
501-KB5	155	42/73	42/73	0.80	1.53
501-KC5	174	42/76	NA ^c /NA ^c	NA ^b	NA ^c
501-KH	155	42/73	25/84	NA ^b	NA ^b
570-K	101	42/58	NA ^c /NA ^c	NA ^b	NA ^c
571-K	101	42/58	NA ^c /NA ^c	0.80	NA ^c
Westinghouse					
251B11/12	220	42/81	25/89	1.0	1.8
501D5	190	25/87	25/87	1.6	1.6
Siemens					
V84.2	212	42/80	55/74	2.0	2.0
V94.2	212	55/74	55/74	1.6	1.6
V64.3	380	75/80	75/80	1.6	1.4
V84.3	380	75/80	75/80	1.6	1.4
V94.3	380	75/80	75/80	1.6	1.4

^aA NO_x emissions level of 25 ppmv can be achieved, but turbine maintenance requirements increase over those required for 42 ppmv.

**TABLE 5-6. MANUFACTURER'S GUARANTEED NO_x REDUCTION EFFICIENCIES
AND ESTIMATED WATER-TO-FUEL RATIOS FOR DISTILLATE
OIL FUEL OPERATION^{5-11, 21-24}**

Manufacturer/model	NO _x emissions level, ppmv at 15% O ₂ /NO _x percent reduction			Water-to-fuel ratio (lb water to lb fuel)	
	Uncontrolled	Water injection	Steam injection	Water injection	Steam injection
General Electric					
LM1600	237	42/82	75/70	NA ^a	NA ^a
LM2500	345	42/88	75/78	0.99	NA ^a
LM5000	364	42/88	110/70	NA ^a	NA ^a
LM6000	417	42/90	110/74	NA ^a	NA ^a
MS5001P	211	65/69	65/69	0.79	1.06
MS6001B	267	65/76	65/76	0.73	1.20
MS7001E	228	65/72	65/72	0.67	1.19
MS7001F	353	65/82	65/77	0.72	1.35
MS9001E	241	65/73	65/72	0.65	1.16
MS9001F	353	65/82	65/76	NA ^a	NA ^a
Asea Brown Boveri					
GT10	200	42/79	42/79	0.75	1.25
GT8	680	42/94	60/91	1.62	2.15
GT11N	560	42/88	42/93	1.50	2.28
GT35	360	42/88	60/83	1.00	1.20
Solar Turbines, Inc.					
T-1500 Saturn	150	60/60	NA ^b /NA ^b	0.46	NA ^b
T-4500 Centaur	179	60/66	NA ^b /NA ^b	0.60	NA ^b
Type H Centaur	160	60/63	NA ^b /NA ^b	0.72	NA ^b
Taurus	168	60/64	NA ^b /NA ^b	0.96	NA ^b
T-12000 Mars	267	60/78	NA ^b /NA ^b	1.00	NA ^b
T-14000 Mars	NA ^a	60/NA ^a	NA ^b /NA ^b	NA ^a	NA ^b
Allison/GM					
501-KB5	231	56/76	NA ^b /NA ^b	NA ^a	NA ^b
501-KC5	NA ^a	NA ^a /NA ^a	NA ^b /NA ^b	NA ^a	NA ^b
501-KH	231	56/76 ^a	50/78	NA ^a	NA ^a
570-K	182	65/64 ^a	NA ^b /NA ^b	NA ^a	NA ^b
571-K	182	65/64 ^a	NA ^b /NA ^b	NA ^a	NA ^b
Westinghouse					
251B11/12	355	65/82	42/88	1.0	1.8
501D5	250	42/83	42/83	1.0	1.6
Siemens					
V84.2	360	42/88	55/85	1.4	2.0
V94.2	360	42/88	55/85	1.4	1.6
V64.3	530	75/86	75/86	1.2	1.4
V84.3	530	75/86	75/86	1.2	1.4
V94.3	530	75/86	75/86	1.2	1.4

^aData not available.

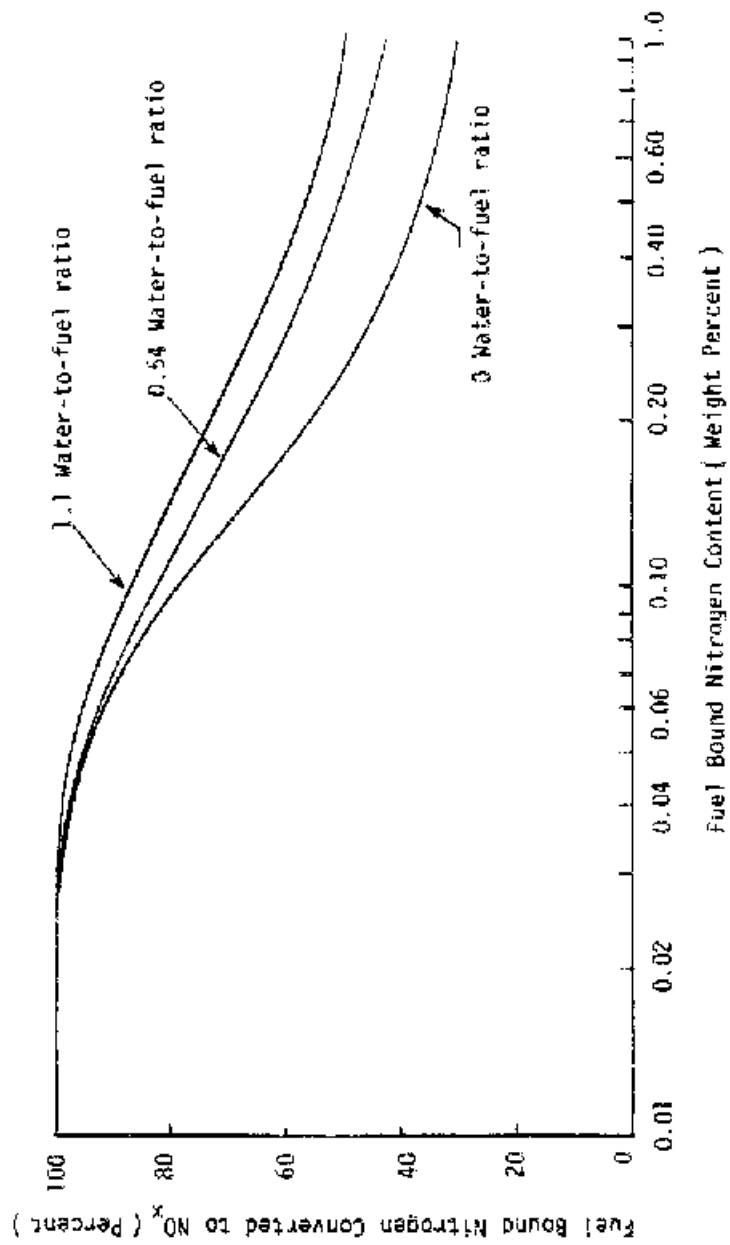
distillate oil fuels, respectively, based on information provided by gas turbine manufacturers. For natural gas fuel, WFR's for water or steam injection range from 0.33 to 2.48 to achieve controlled NO_x emission levels ranging from 25 to 75 ppmv, corrected to 15 percent oxygen. For oil fuel, WFR's range from 0.46 to 2.28 to achieve controlled NO_x emission levels ranging from 42 to 110 ppmv, corrected to 15 percent oxygen. Nitrogen oxide reduction efficiency increases as the WFR

increases. As shown in Tables 5-5 and 5-6, reduction efficiencies of 70 to 90 percent are common. Note that, in general, the WFR's for steam are higher than for water injection because water acts as a better heat sink than steam due to the heat absorbed by vaporization; therefore, higher levels of steam than water must be injected for a given reduction level.

The combustor geometry and injection nozzle design and location also affect the performance of wet controls. For maximum NO_x reduction efficiency, the water must be atomized and injected in a spray pattern that provides a homogeneous mixture of water droplets and fuel in the combustor. Failure to achieve this mixing yields localized hot spots in the combustor that produce increased NO_x emissions.

The type of fuel affects the performance of wet controls. In general, lower controlled NO_x emission levels can be achieved with gaseous fuels than with oil fuels. The FBN content also affects the performance of wet controls. Those fuels with relatively high nitrogen content, such as coal-derived liquids, shale oil, and residual oils, result in significant fuel NO_x formation. Natural gas and most distillate oils are low-nitrogen fuels. Consequently, fuel NO_x formation is minimal when these fuels are burned.

Wet controls serve only to lower the flame temperature and therefore are an effective control only for thermal NO_x formation; water injection may in fact increase the rate of fuel NO_x formation, as shown in Figure 5-1.²⁵ The mechanisms responsible for this potential increase were not identified.



5.1.4 Achievable NO_x Emissions Levels Using Wet Controls

This section presents the achievable controlled NO_x emission levels for wet injection, as guaranteed by gas turbine manufacturers. Emission test data, obtained using EPA Test Method 20 or equivalent, are also presented.

Guaranteed NO_x emission levels as provided by gas turbine manufacturers for wet controls are shown in Figures 5-2 and

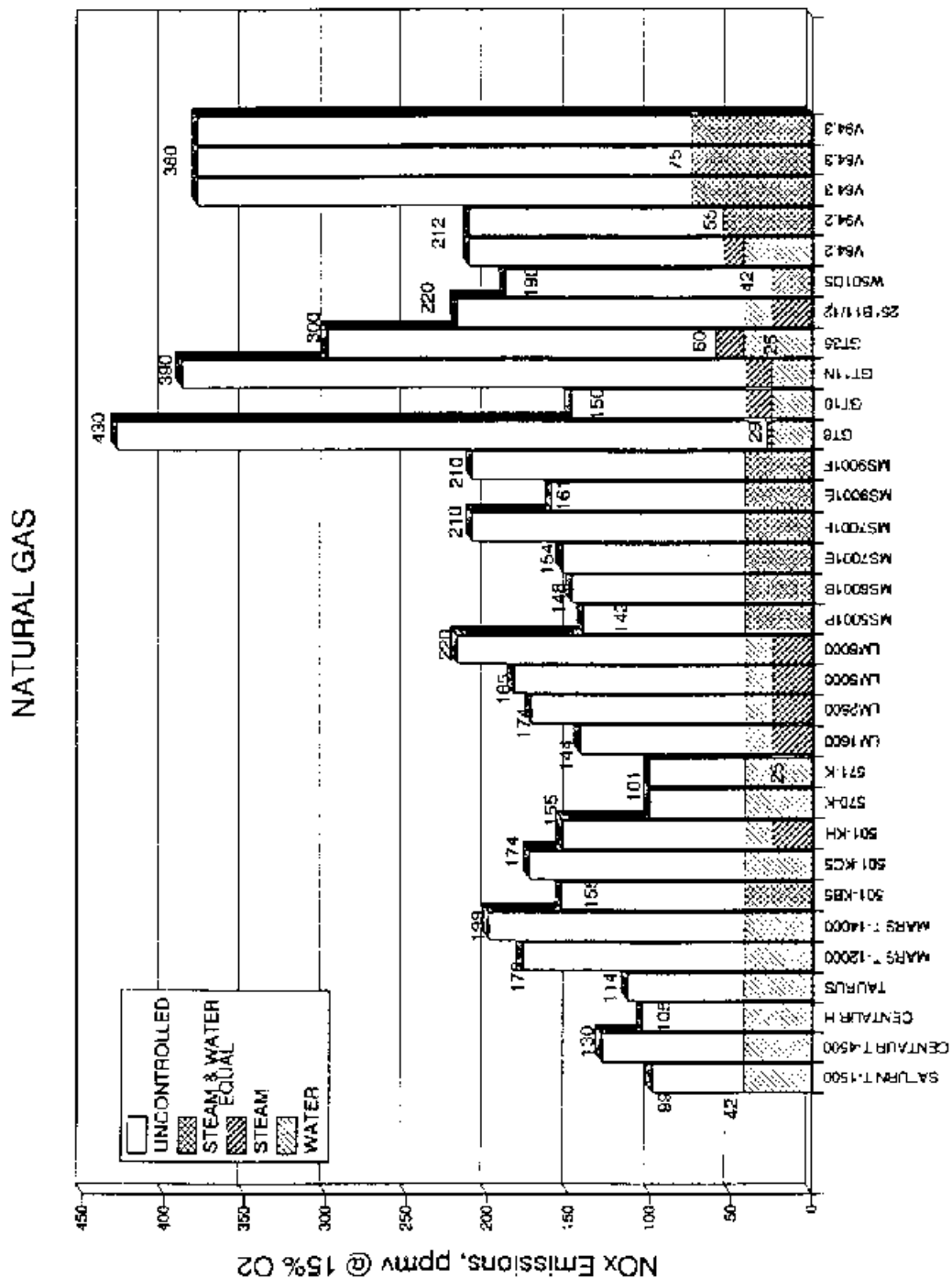
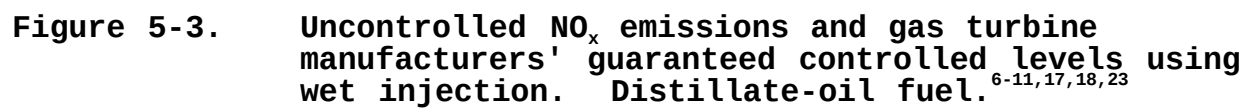


Figure 5-1. Percentage of fuel-bound nitrogen converted to NO_x versus the fuel-bound nitrogen content and the water-to-fuel ratio for controlled NO_x emissions operation after 1000 hours of engine operation. 1840a. 25, 26. 6-11, 17, 18, 23. Figure 5-2. 1840a. 25, 26. 6-11, 17, 18, 23. manufacturers' guaranteed controlled levels using wet injection. Natural gas fuel.



5-3. These figures show manufacturers' guaranteed NO_x emission levels of 42 ppmv for most natural gas-fired turbines, and from 42 to

75 ppmv for most oil-fired turbines. The percent reduction in NO_x emissions varies for each turbine, ranging from 60 to 94 percent depending upon each model's uncontrolled emission level and whether water or steam is injected.

Emissions data for water and steam injection are presented to show the effects of wet injection on NO_x emissions. These data show:

1. That NO_x emissions decrease with increasing WFR's; and
2. That NO_x emissions are higher for oil fuel than for natural gas.

From the available data, reduction efficiencies of 70 to over 85 percent were achieved. The emission data and WFRs shown for specific turbine models may not reflect the emission levels of current production models, since manufacturers periodically update or otherwise modify their turbines, thereby altering specific emissions levels.

Each emission test in the following figures consists of one or more data points. Where data points were obtained under similar conditions, they are grouped together and presented as a single test. For these cases, each data point, along with the arithmetic average of all of the data points, is shown.

The nomenclature used to identify the tests consists of two letters followed by a number. The first letter of the two-letter designator specifies the turbine type. These types are as follows:

<u>Letter</u>	<u>Turbine type</u>
A	Aircraft-derivative turbine
H	Heavy-duty turbine
T	Small and low-efficiency turbine (less than 7.5 MW output, less than 30 percent simple-cycle efficiency)

The second letter identifies the facility. The number identifies the number of tests performed at the facility. Tests performed at the same facility on different turbines or at different times have the same two-letter designator but are followed by different test numbers. The short horizontal lines represent the average of the test data.

Also presented are the available data on the turbine, wet controls, uncontrolled NO_x emissions, percent NO_x reduction, and fuel type. All of the data shown are representative of the performance of wet controls when the turbine is operated at base load or peak load. These loads represent the worst-case conditions for NO_x emission reduction. Information on the WFR, turbine model, efficiency, control type, and fuel are included with the emission test data.

Figures 5-4, 5-5, and 5-6 present the emission test data

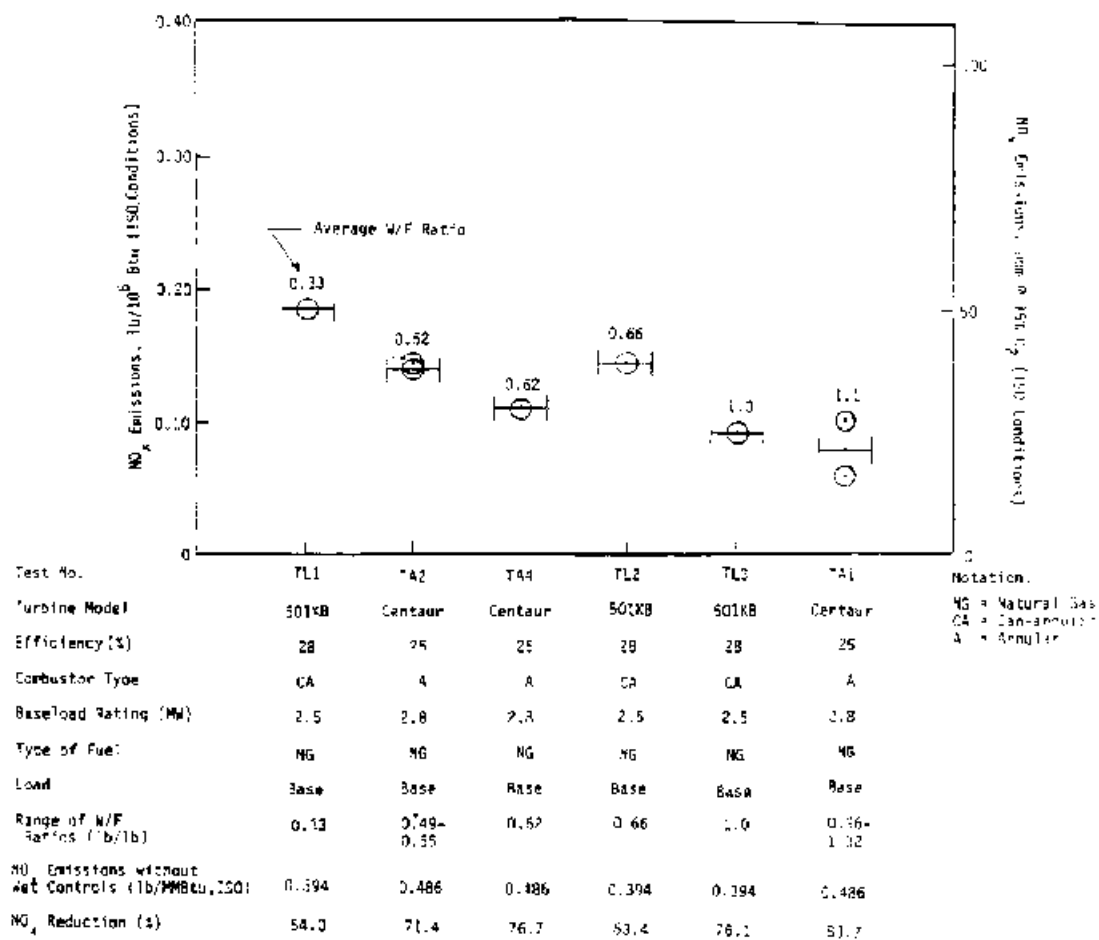


Figure 5-4. Nitrogen oxide emission test data for small, low-efficiency gas turbines with water injection firing natural gas.²⁷

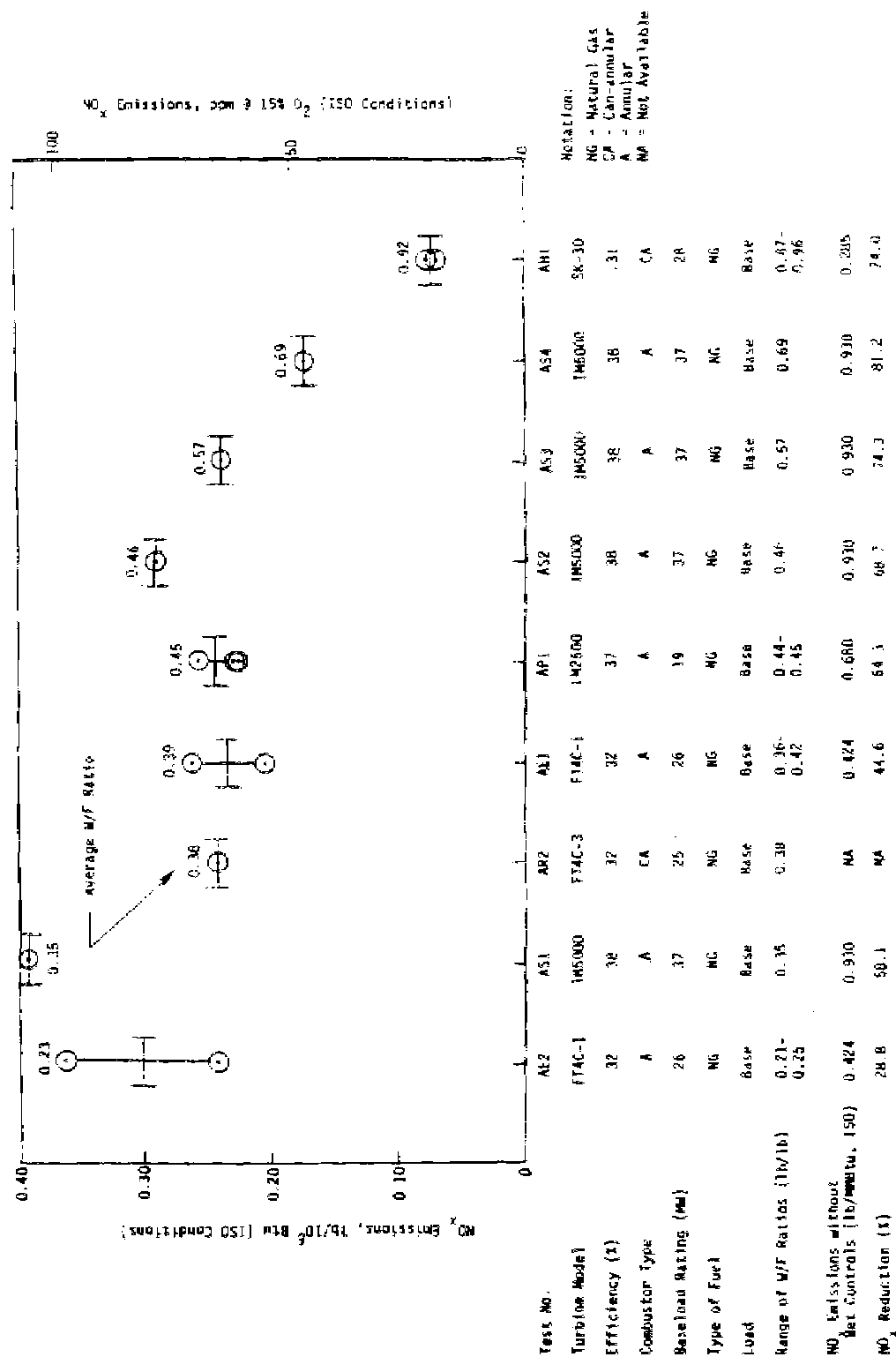


Figure 5-5. Nitrogen oxide emission test data for aircraft-derivative gas turbines with water injection firing natural gas.²⁷

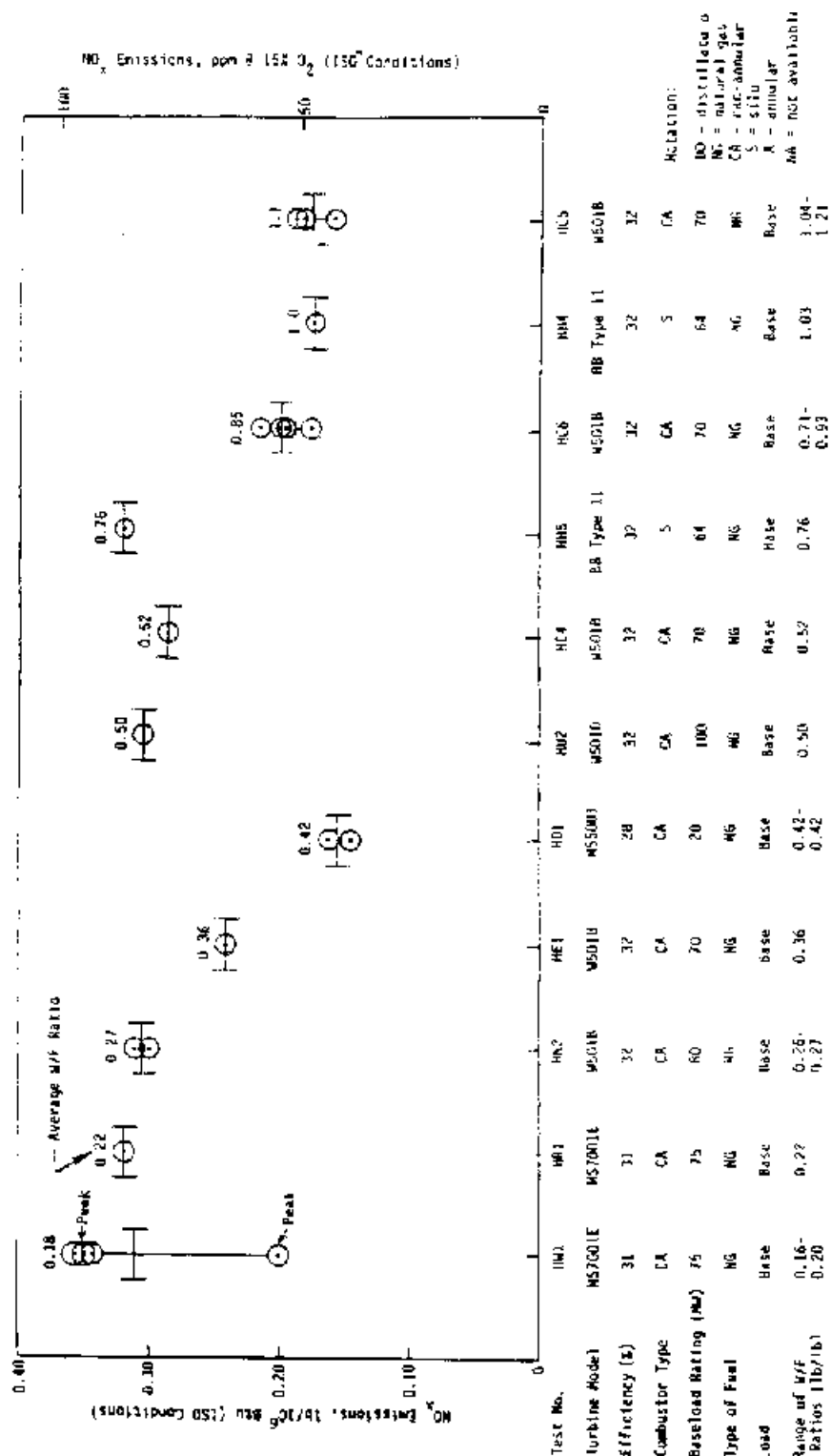


Figure 5-6. Nitrogen oxide emission test data for heavy-duty gas turbines with water injection firing natural gas.²⁷

for water injection on turbines fired with natural gas. These turbines have NO_x emissions ranging from approximately 20 to 105 ppm with WFR's ranging from 0.16 to 1.32. Turbine sizes range from 2.8 to 97 MW. Based on these data, water injection is effective on all types of gas turbines and NO_x emission levels decrease as the WFR increases. However, some turbines require a higher WFR to meet a specific emission level. For example, the gas turbines at sites HH and HC (Figure 5-6) require much higher WFR's to achieve NO_x emission levels similar to the other gas turbine models shown. This particular gas turbine also has the highest uncontrolled NO_x emission levels. Conversely, the gas turbine at site AH, shown in Figure 5-5, has the lowest uncontrolled NO_x emission level and requires the least amount of water to achieve a given emission level. Uncontrolled NO_x emission levels vary for different turbine models depending upon design factors such as efficiency, firing temperature, and the extent of combustion controls incorporated in the combustor design (see Section 4.2.1.1). In general, aircraft-derivative and heavy-duty gas turbines require similar WFR's to achieve a specific emission level. Small, low-efficiency gas turbines require less water to achieve a specific emission level.

The NO_x emissions for turbines firing distillate oil are shown in Figures 5-7, 5-8, and 5-9. The data range from

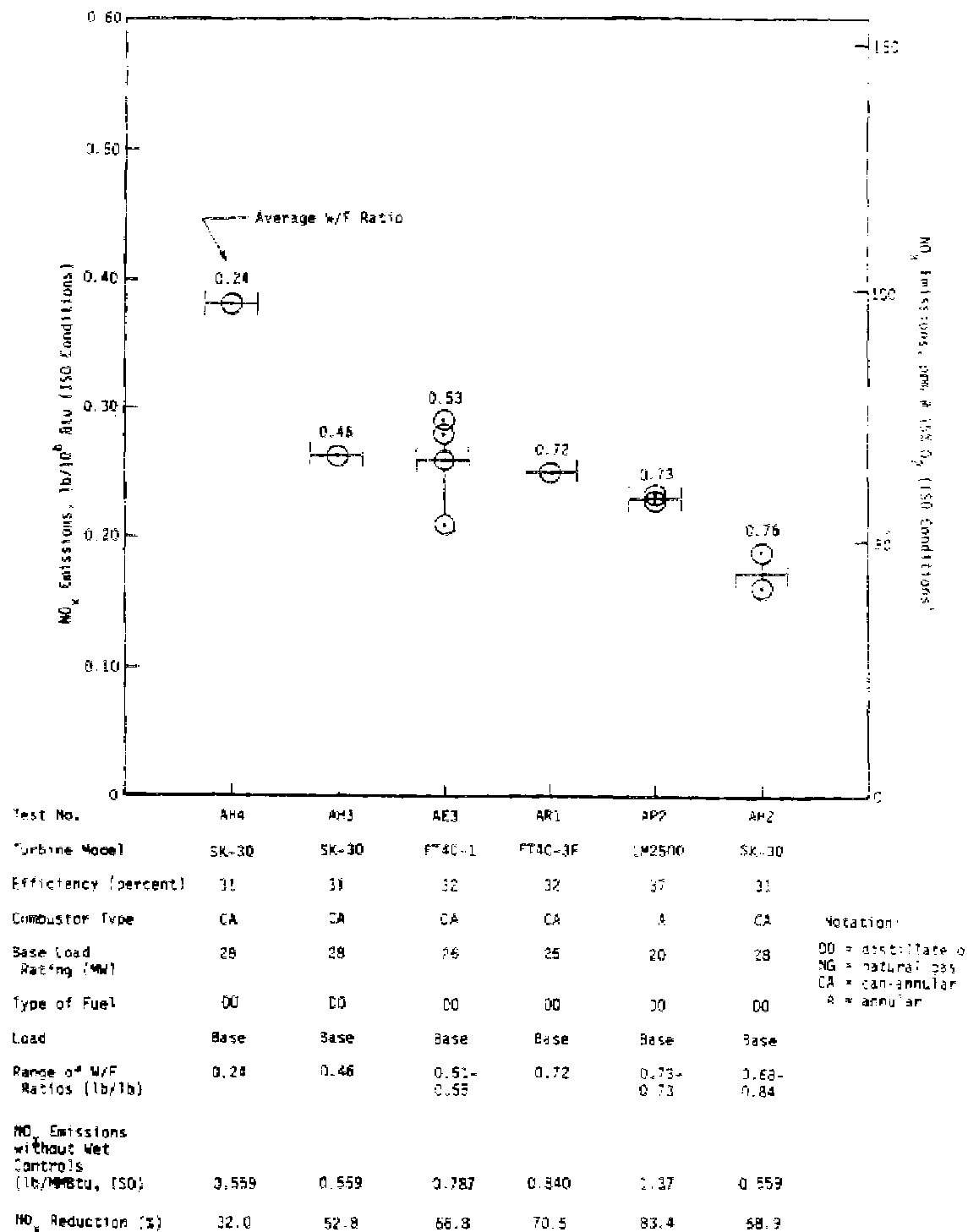


Figure 5-7. Nitrogen oxide emission test data for aircraft-derivative gas turbines with water injection firing distillate oil.²⁷

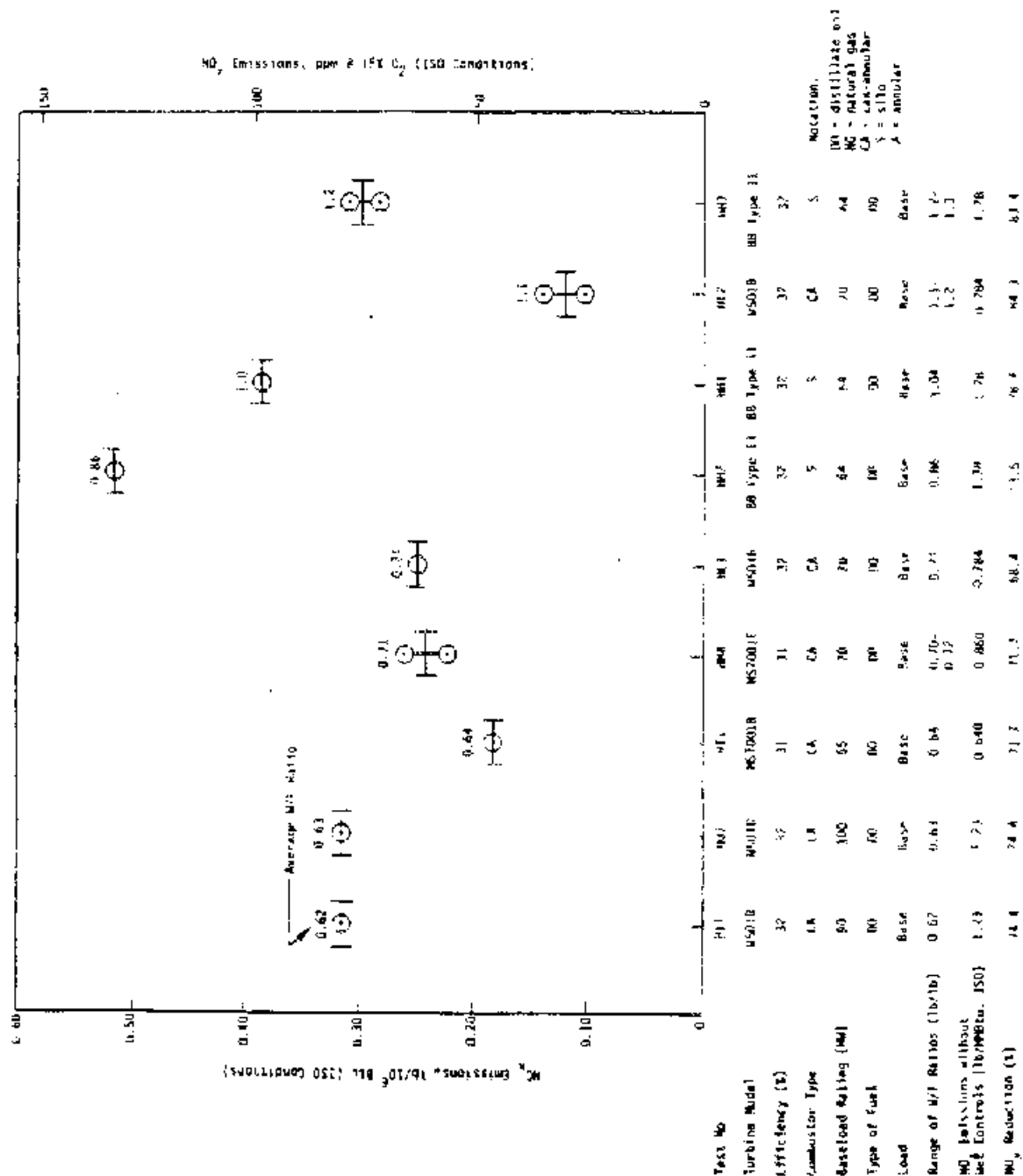


Figure 5-9. Nitrogen oxide emission test data for heavy-duty gas turbines with water injection and WFRs greater than 0.5 and firing distillate oil.²⁷

approximately 30 to 135 ppm, with WFR's ranging from 0.24 to 1.31. The gas turbine sizes range from 19 to 95 MW. The data for distillate oil-fired turbines show the same general trends as the data for natural gas-fired turbines. Site HH (Figure 5-9)

again shows that higher WFR's are required due to the high uncontrolled NO_x emissions from this gas turbine. Also, by comparing the emission data for the distillate oil-fired turbines and natural gas-fired turbines, the data show that burning distillate oil requires higher WFR's than does burning natural gas for a given level of NO_x emissions. Higher WFR's are required because distillate oil produces higher uncontrolled NO_x levels than does natural gas (see Section 4.2.1.2).

The NO_x emission test data for steam injection are presented in Figures 5-10

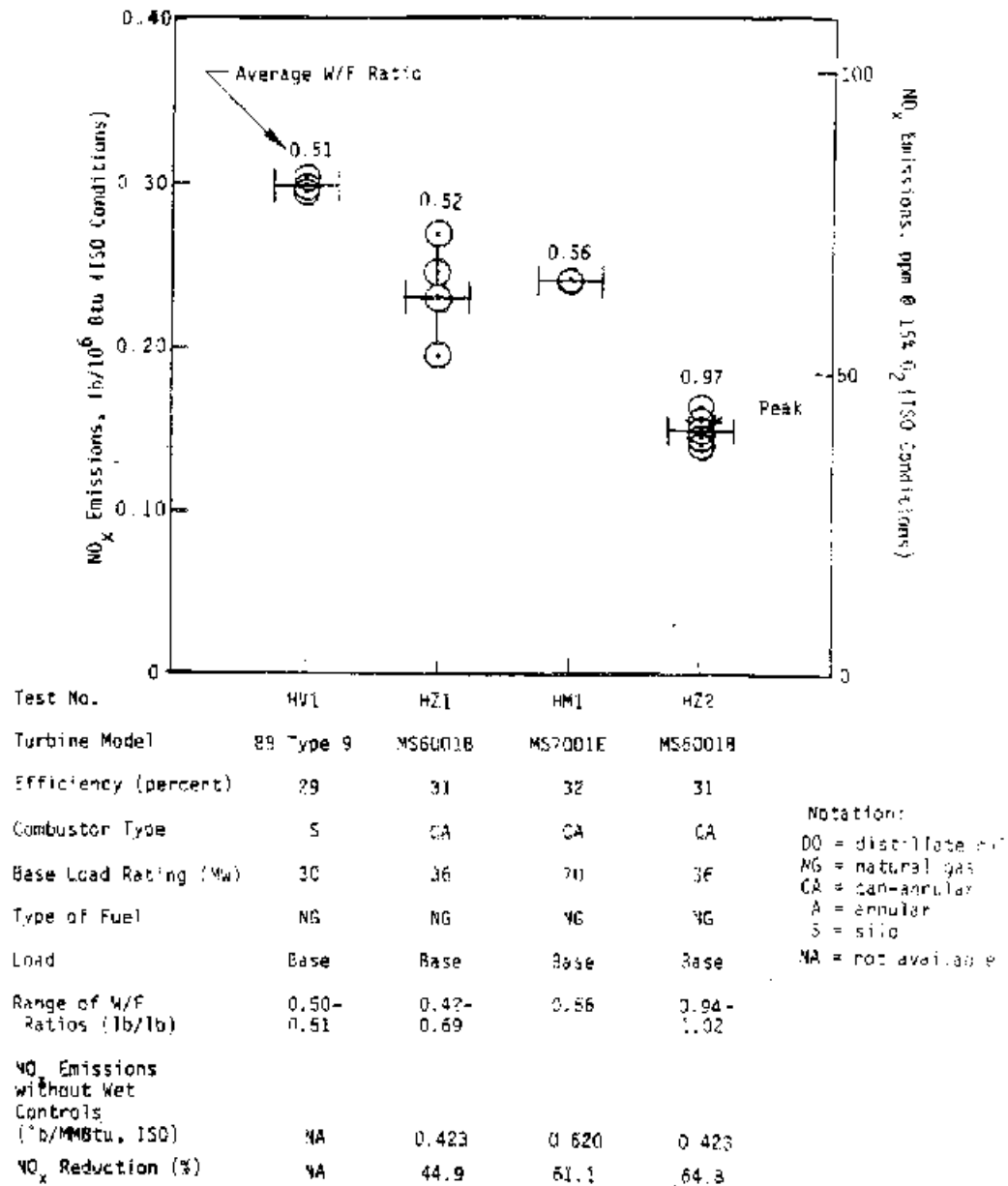


Figure 5-10. Nitrogen oxide emission test data for gas turbines with steam injection firing natural gas.²⁷

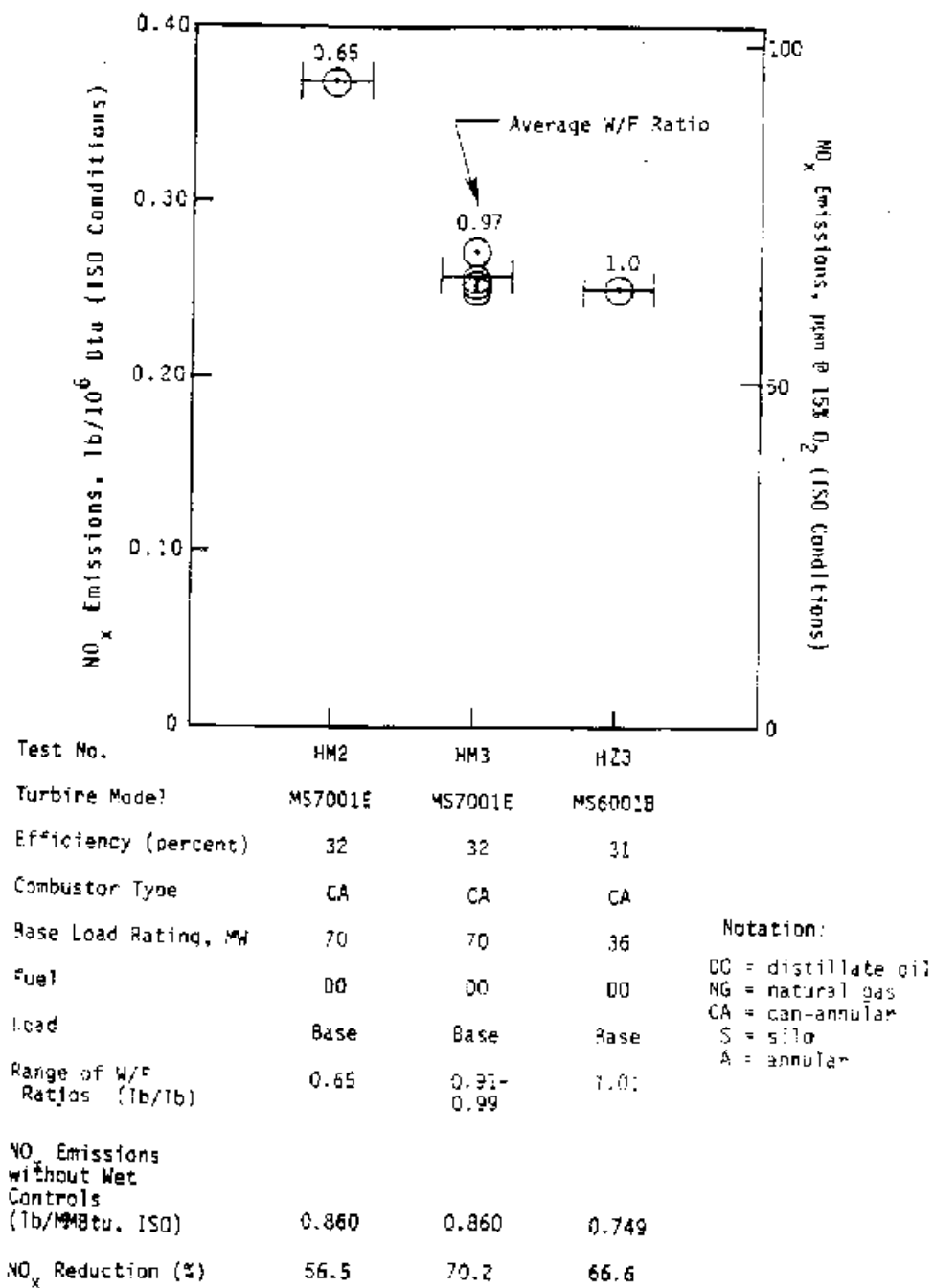


Figure 5-11. Nitrogen oxide emission test data for gas turbines with steam injection firing distillate oil.²⁷

and 5-11 for natural gas-fired turbines and distillate oil-fired turbines, respectively. The turbines firing natural gas have NO_x emissions ranging from approximately 40 to 80 ppm, with WFR's ranging from 0.50 to 1.02. The gas turbine sizes range from 30 to 70 MW.

The NO_x emissions for turbines firing distillate oil range from approximately 65 to 95 ppm, with WFR's ranging from 0.65 to 1.01, and the gas turbine sizes tested were 36 and 70 MW. Fewer data points are available for steam injection than for water injection. However, the available data for both distillate oil-fired and natural gas-fired turbines show that NO_x emissions decrease as the steam-to-fuel ratio increases.

Reductions in NO_x emissions similar to water injection with oil-fired turbines have been achieved using water-in-oil emulsions. Results of emission tests for four turbines are shown in Table 5-7

**TABLE 5-7. ACHIEVABLE GAS TURBINE NO_x EMISSION REDUCTIONS
FOR OIL-FIRED TURBINES USING WATER-IN-OIL EMULSIONS¹⁹**

				NO _x emissions, ppmv at 15 percent O ₂		
Turbine manufacturer	Turbine model	Power output, MW	Water-to- fuel ratio	Uncontrolled	Controlled	Percent reduction
Turbo Power and Marine	A4	35	0.65	184	53	68
	A9	33	0.55	150	50	66
	A9	33	0.92	126	29	77
General Electric	MS5001	15	0.49	131	60	54

. The controlled NO_x emissions range from 29 to 60 ppmv, corresponding to NO_x reductions of 54 to 77 percent.¹⁹ The controlled NO_x emission levels and percent reduction are consistent with those achieved using conventional water injection. Limited testing has shown that the emulsion achieves a given NO_x reduction level with a lower WFR than does a separate water injection arrangement. Test data for one oil-fired turbine showing a comparison of the WFR's for a water-in-oil emulsion versus a separate water injection system are shown in Figure 5-12

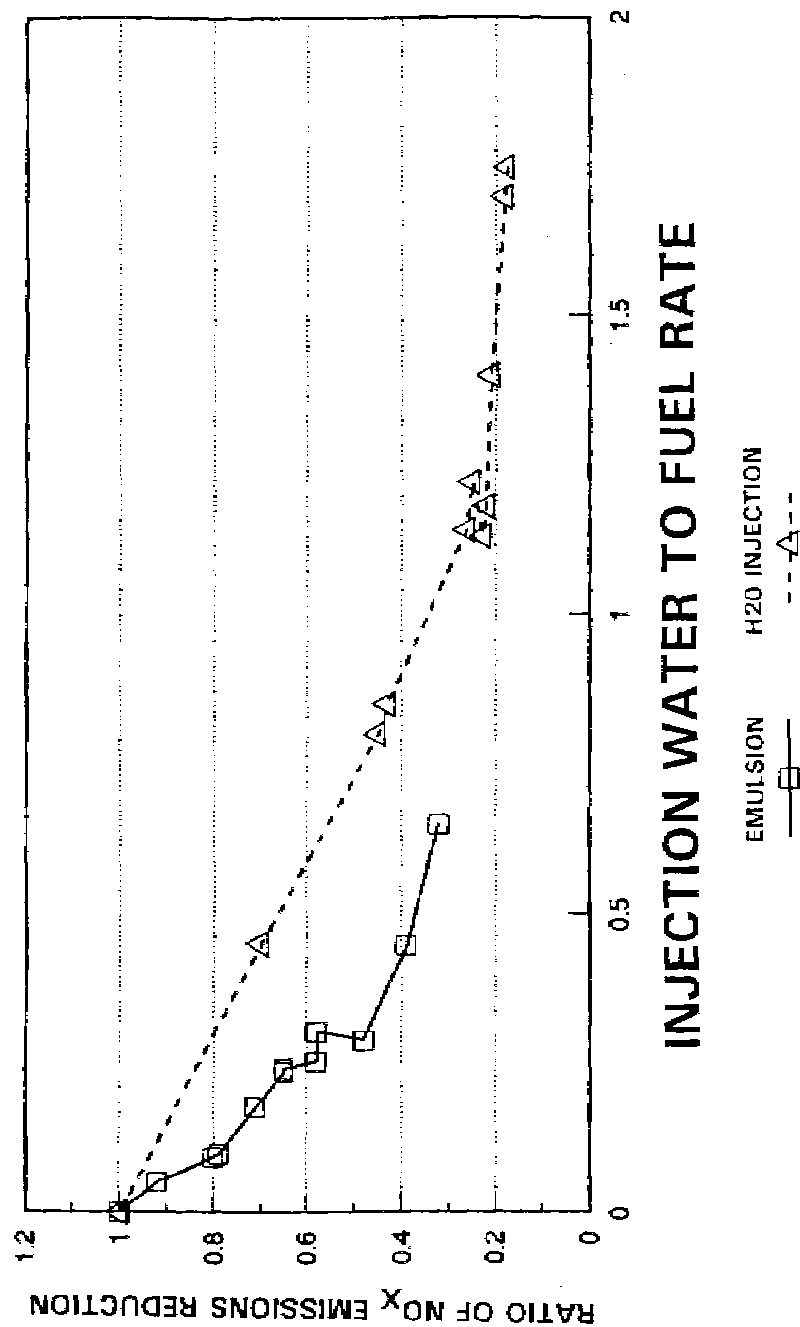


Figure 5-12. Comparison of the WFR requirement for water-in-oil emulsion versus separate water injection for an oil-fired turbine.²⁸

. As shown here, NO_x reductions achieved by a water injection system at a WFR of 1.0 can be achieved by a water-in-oil emulsion at a WFR of 0.6.

On a mass basis, the reduction in NO_x emissions using water injection is shown in Table 5-8

TABLE 5-8. UNCONTROLLED NO_x EMISSIONS AND POTENTIAL NO_x REDUCTIONS FOR GAS TURBINES USING WATER INJECTION

Gas turbine model	Power output, MW ^a	NO _x emissions					
		Uncontrolled		Controlled		NO _x reduction	
		Gas fuel, lb/hr ^b	Oil fuel, lb/hr ^b	Gas fuel, lb/hr ^b	Oil fuel, lb/hr ^b	Gas fuel, tons/yr ^c	Oil fuel, tons/yr ^c
Saturn	1.1	6.4	9.9	2.8	4.1	14.3	23.3
Centaur	3.3	22.0	31.2	7.4	10.8	58.5	81.5
Centaur "H"	4.0	20.8	32.6	8.6	12.7	48.6	79.8
Taurus	4.5	24.7	37.6	9.4	13.9	61.1	94.9
Mars T-12000	8.8	69.4	107	17.0	24.9	210	329
Mars T-14000	10.0	85.4	NA ^d	18.7	NA ^d	267	NA ^d
501-KB5	4.0	31.6	48.5	8.9	12.2	90.9	145
570-K	4.9	22.7	41.0	9.8	15.2	51.8	103
571-K	5.9	24.2	44.0	10.4	16.3	55.1	111
LM1600	14.0	74.1	127	22.4	23.2	207	414
LM2500	22.7	146	301	36.4	37.9	438	1,050
LM5000	34.5	232	474	54.5	56.6	710	1,670
LM6000	43.0	310	609	61.3	63.5	996	2,180
MS5001P	26.8	181	274	55.5	87.4	503	747
MS6001B	39.0	250	459	73.2	116	704	1,370
MS7001E	84.7	544	822	154	243	1,560	2,320
MS7001F	161	1,290	2,190	267	417	4,090	7,090
MS9001E	125	810	1,320	219	369	2,370	3,820
MS9001F	229	1,850	3,150	382	600	5,850	10,200
GT8	47.4	899	1,440	54.1	92.3	3,380	5,410
GT10	22.6	143	196	24.6	42.6	472	614
GT11N	83.3	1,350	1,990	99.0	154	5,060	7,334
GT35	16.9	214	264	30.9	31.9	730	929
251B11/12	49.2	453	741	89.5	141	1,450	2,400
501D5	109	843	1,120	115	196	2,910	3,710
V84.2	105	858	1,570	176	190	2,730	5,520
V94.2	153	1,250	2,290	335	276	3,650	8,050
V64.3	61.5	859	1,290	176	188	2,740	4,390
V84.3	141	1,930	2,910	395	426	6,150	9,920
V94.3	204	2,790	4,170	571	611	8,890	14,200

^aPower output at ISO conditions, without wet injection, with natural gas fuel.

^bBased on ppmv levels shown in Tables 5-5 and 5-6. See Appendix A for conversion from ppmv to lb/hr.

^cBased on 8,000 hours operation per year.

^dData not available.

TABLE 5-9 shows UNCONTROLLED NO_x EMISSIONS AND POTENTIAL NO_x REDUCTIONS FOR GAS TURBINES USING STEAM INJECTION.

Gas turbine model	Power output, MW ^a	NO _x emissions					
		Uncontrolled		Controlled		NO _x reduction	
		Gas fuel, lb/hr ^b	Oil fuel, lb/hr ^b	Gas fuel, lb/hr ^b	Oil fuel, lb/hr ^b	Gas fuel, tons/yr ^{c,d}	Oil fuel, tons/yr ^{c,d}
Saturn	1.1	6.4	9.9	6.4	9.9	0	0
Centaur	3.3	22.0	31.2	22.0	31.2	0	0
Centaur "H"	4.0	20.8	32.6	20.8	32.6	0	0
Taurus	4.5	24.7	37.6	24.7	37.6	0	0
Mars T-12000	8.8	69.4	107	69.4	107	0	0
501-KB5	4.0	31.6	48.5	8.6	48.5	194	0
570-K	4.9	22.7	41.0	22.7	41.0	0	0
571-K	5.9	24.2	44.0	24.2	44.0	0	0
LM1600	14.0	74.1	127	13.0	40.5	245	345
LM2500	22.7	146	301	21.2	66.0	499	938
LM5000	34.5	232	474	31.7	145	802	1,320
LM6000	43.0	310	609	35.6	162	1,100	1,790
MS5001P	26.8	181	274	54.1	85.3	508	755
MS6001B	39.0	250	459	71.4	113	711	1,380
MS7001E	84.7	544	822	150	237	1,580	2,340
MS7001F	161	1,290	2,190	260	407	4,110	7,130
MS9001E	125	810	1,320	214	360	2,390	3,850
MS9001F	229	1,850	3,150	373	585	5,890	10,200
GT8	47.4	899	1,440	61.2	129	3,350	5,260
GT10	22.6	143	196	40.4	41.6	410	618
GT11N	83.3	1,350	1,990	147	151	4,830	7,350
GT35	16.9	214	264	43.1	44.4	681	878
251B11/12	49.2	453	741	52.0	88.6	1,600	2,610
501D5	109	843	1,120	112	191	2,920	3,730
V84.2	105	858	1,570	225	242	2,530	5,310
V94.2	153	1,250	3,290	327	353	3,690	7,740
V64.3	61.5	859	1,290	171	184	2,750	4,410
V84.3	141	1,930	2,910	386	415	6,190	9,960
V94.3	204	2,790	4,170	557	596	8,940	14,300

^aPower output at ISO conditions, without wet injection, with natural gas fuel.

^bBased on ppmv levels shown in Tables 5-5 and 5-6. See Appendix A for conversion from ppmv to lb/hr.

As an example, a 21.8 MW turbine burning natural gas fuel can reduce NO_x emissions by 452 tons/yr (8,000 hours operation) using water injection and 511 tons/yr using steam injection. This same turbine burning oil fuel will reduce annual NO_x emissions by 1,040 tons using water injection and by 925 tons using steam injection.

5.1.5 Impacts of Wet Controls on CO and HC Emissions

While carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines, water injection may increase these emissions. Figure 5-13

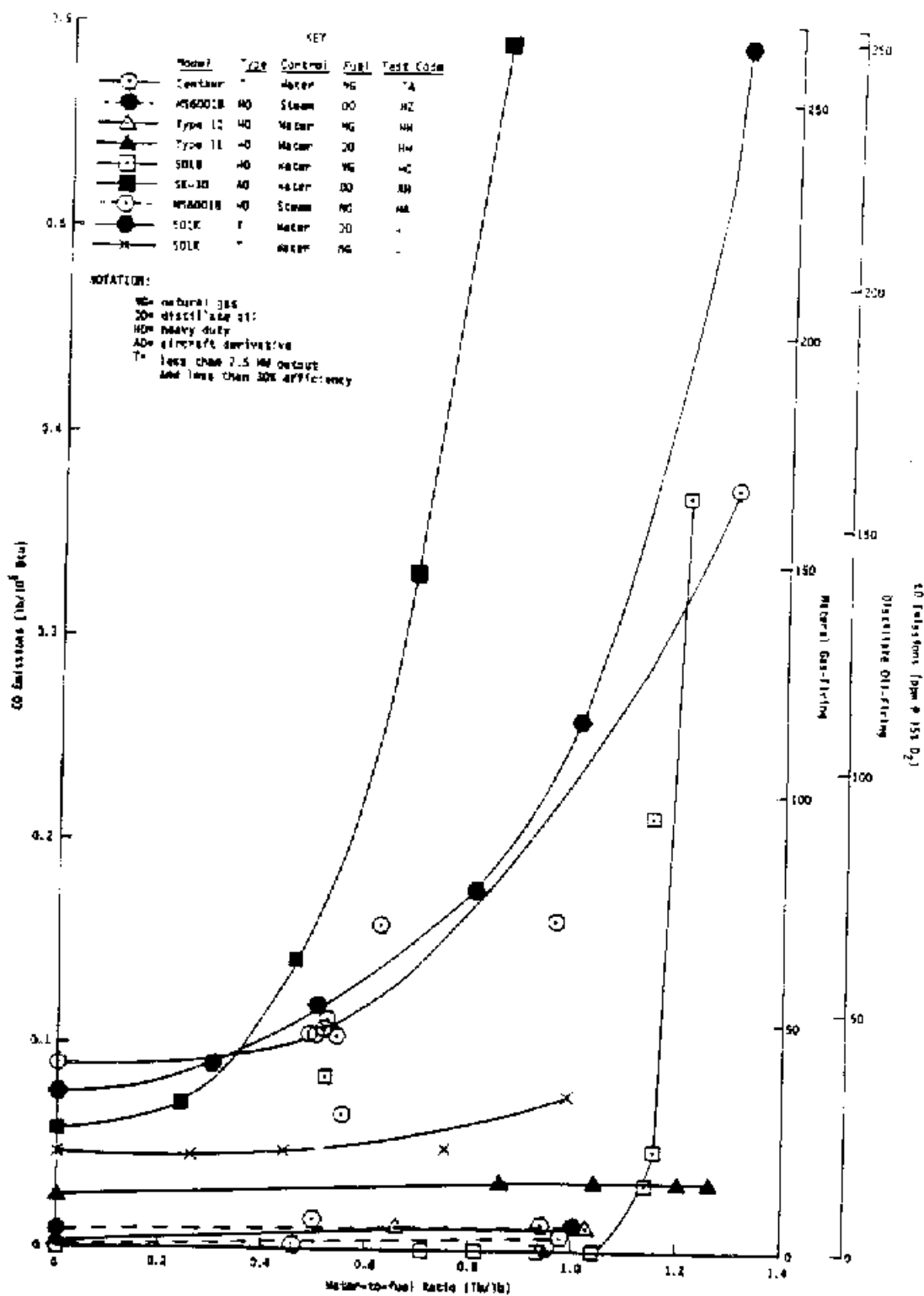


Figure 5-13. Effect of wet injection on CO emissions.²⁹

shows the impact of water injection on CO emissions for several production gas turbines. In many turbines, CO emissions increase as the WFR increases, especially at WFR's above 0.8. Steam injection also increases CO emissions at relatively high WFR's, but the impact is less than that of water injection.^{29, 30}

Water and steam injection also increase HC emissions, but to a lesser extent than CO emissions.^{29,30} The effect of water injection on HC emissions for one turbine is shown in

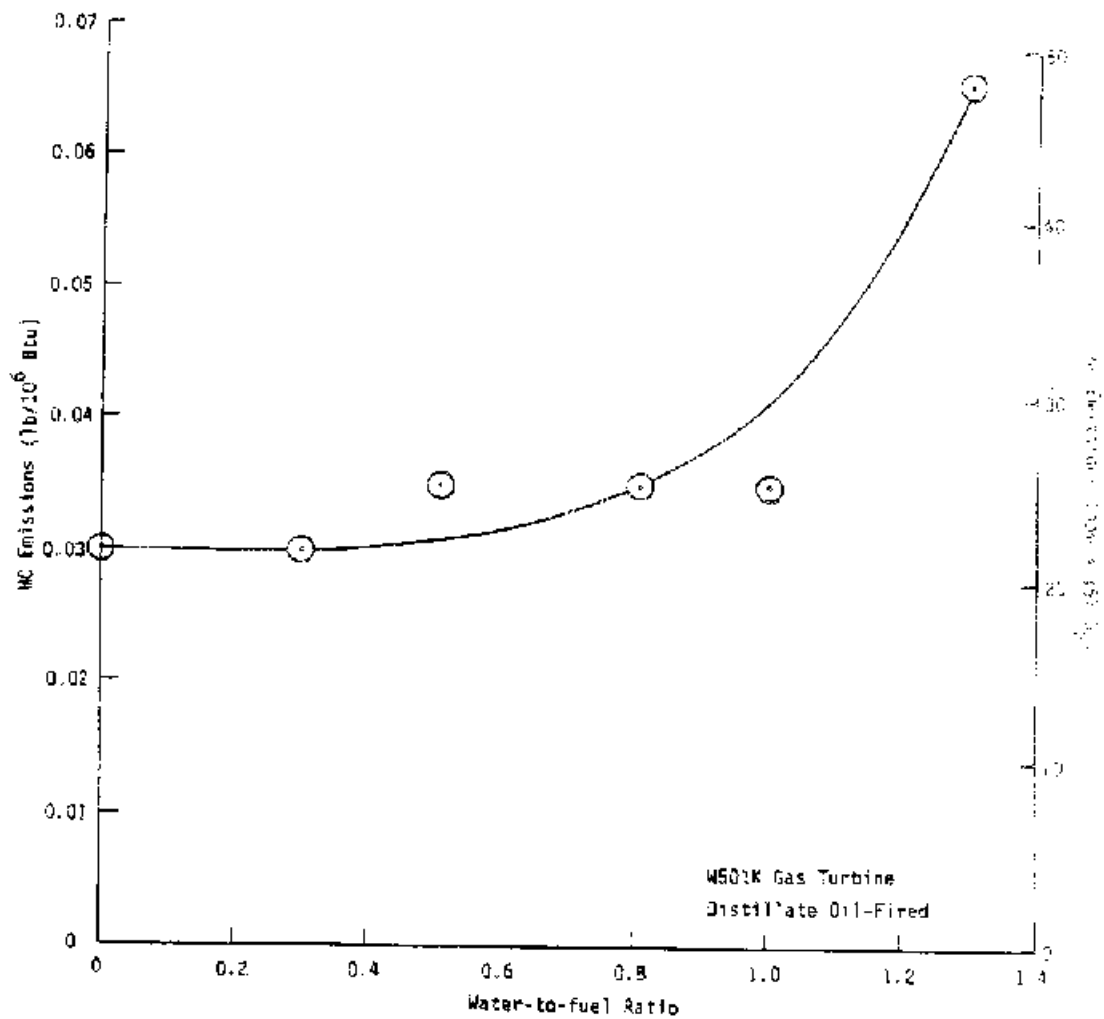


Figure 5-14. Effect of water injection on HC emissions for one turbine model.²⁹

Figure 5-14. Like CO emissions, hydrocarbon emissions increase at WFR's above 0.8.

For applications where the water or steam injection rates required for NO_x emission reductions result in excess CO and/or HC emissions, it may be possible to select an alternative turbine and/or fuel with a relatively flat CO curve, as indicated in Figure 5-13. Another alternative is an oxidation catalyst to reduce these emissions. This oxidation catalyst is an add-on control device that is placed in the turbine exhaust duct or HRSG and serves to oxidize CO and HC to H₂O and CO₂. The catalyst material is usually a precious metal (platinum, palladium, or rhodium), and oxidation efficiencies of 90 percent or higher can be achieved. The oxidation process takes place spontaneously, without the requirement for introducing reactants (such as ammonia) into the flue gas stream.³¹

5.1.6 Impacts of Wet Controls on Gas Turbine Performance

Wet controls affect gas turbine performance in two ways: power output increases and efficiency decreases. The energy from the added mass flow and heat capacity of the injected water or steam can be recovered in the turbine, which results in an increase in power output. For water injection, the fuel energy required to vaporize the water in the turbine combustor, however, results in a net penalty to the overall efficiency of the turbine. For steam injection, there is an energy penalty associated with generating the steam, which results in a net penalty to the overall cycle efficiency. Where the steam source is exhaust heat, which would otherwise be exhausted to the atmosphere, the heat recovery results in a net gain in gas turbine efficiency.³² The actual efficiency reduction associated with wet controls is specific to each turbine and the actual WFR required to meet a specific NO_x reduction. The overall efficiency penalty increases with increasing WFR and is usually higher for water injection than for steam injection due to the heat of vaporization associated with water. The impacts on output and efficiency for one manufacturer's gas turbines are shown in Table 5-10.

**TABLE 5-10. REPRESENTATIVE WATER/STEAM INJECTION
IMPACTS ON GAS TURBINE PERFORMANCE FOR ONE
MANUFACTURER'S HEAVY-DUTY TURBINES³³**

No _x level, ppmv	Water/fuel ratio	Percent overall efficiency change	Percent output change ^a	Remarks
75 NSPS	0.5	-1.8	+3	Oil-fired, simple cycle, water injection
42	1.0	<-3	+5	Natural gas, simple cycle, water injection
42	1.2	-2	+5	Natural gas, combined cycle, steam injection
25	1.2	-4	+6	Natural gas, water injection, multinozzle combustor
25	1.3	-3	+5.5	Natural gas, steam injection, combined cycle (Frame 6 turbine model)

^aCompared with no injection.

5.1.7 Impacts of Wet Controls on Gas Turbine Maintenance

Water injection increases dynamic pressure oscillation activity in the turbine combustor.³³ This activity can, in some turbine models, increase erosion and wear in the hot section of the turbine, thereby increasing maintenance requirements. As a result, the turbine must be removed from service more frequently for inspection and repairs to the hot section components. A summary of the maintenance impacts as provided by manufacturers is shown in Table 5-11.

**TABLE 5-11. IMPACTS OF WET CONTROLS ON GAS TURBINE MAINTENANCE
USING NATURAL GAS FUEL^{5-11, 17, 24}**

Manufacturer/Model	NO _x emissions, ppmv @ 15% O ₂			Inspection interval, hours		
	Standard combustor	Water injection	Steam injection	Standard	Water injection	Steam injection
General Electric						
LM1600	133	42/25	25	25,000	16,000 ^a	25,000
LM2500	174	42/25	25	25,000	16,000 ^a	25,000
LM5000	185	42/25	25	25,000	16,000 ^a	25,000
LM6000	220	42/25	25	25,000	16,000 ^a	25,000
MS5001P	142	42	42	12,000	6,000	6,000
MS6001B	148	42	42	12,000	6,000	8,000
MS7001E	154	42	42	8,000	6,500	8,000
MS7001F	179	42	42	8,000	8,000	8,000
MS9001E	176	42	42	8,000	6,500	8,000
MS9001F	176	42	42	8,000	8,000	8,000
Asea Brown Boveri						
GT10	150	25	42	80,000 ^b	80,000 ^b	80,000 ^b
GT8	430	25	29	24,000	24,000	24,000
GT11N	400	25	25	24,000	24,000	24,000
GT35	300	42	60	80,000 ^b	80,000 ^b	80,000 ^b
Siemens Power Corp.						
V84.2	212	42	55	25,000	25,000	25,000
V94.2	212	55	55	25,000	25,000	25,000
V64.3	380	75	75	25,000	25,000	25,000
V84.3	380	75	75	25,000	25,000	25,000
V94.3	380	75	75	25,000	25,000	25,000
Solar Turbines, Inc.						
T-1500 Saturn	99	42	NA ^c	NA ^d	NA ^d	NA ^c
T-4500 Centaur	150	42	NA ^c	NA ^d	NA ^d	NA ^c
Type H Centaur	105	42	NA ^c	NA ^d	NA ^d	NA ^c
Taurus	114	42	NA ^c	NA ^d	NA ^d	NA ^c
T-12000 Mars	178	42	NA ^c	NA ^d	NA ^d	NA ^c
T-14000 Mars	199	42	NA ^c	NA ^d	NA ^d	NA ^c
Allison/General Motors						
501-KB5	155	42	NA ^c	25,000	17,000	NA ^d
501-KC5	174	42	NA ^c	30,000	22,000	NA ^d
501-KH	155	42	25	25,000	17,000	20,000
570-K	101	42	NA ^c	20,000	12,000	NA ^d
571-K	101	42	NA ^c	20,000	12,000	NA
Westinghouse						
251B11/12	220	42	25	8,000	8,000	8,000
501D5	190	25	25	8,000	8,000	8,000

^aApplies only to 25 ppmv level. No impact for 42 ppmv.

^bThis interval applies to time between overhaul (TBO).

^cSteam injection is not available for this model.

^dData not available.

As this table shows, the maintenance impact, if any, varies from manufacturer to manufacturer and model to model. Some manufacturers stated that there is no impact on maintenance intervals associated with water or steam injection for their turbine models. Data were provided only for operation with natural gas.

5.2 COMBUSTION CONTROLS

The formation of both thermal NO_x and fuel NO_x depends upon combustion conditions, so modification of these conditions affects NO_x formation. The following combustion modifications are used to control NO_x emission levels:

1. Lean combustion;
2. Reduced combustor residence time;
3. Lean premixed combustion; and
4. Two-stage rich/lean combustion.

These combustion modifications can be applied singly or in combination to control NO_x emissions.

The mechanisms by which each of these techniques reduce NO_x formation, their applicability to new gas turbines, and the design or operating factors that influence NO_x reduction performance are discussed below by control technique.

5.2.1 Lean Combustion and Reduced Combustor Residence Time

5.2.1.1 Process Description. Gas turbine combustors were originally designed to operate with a primary zone equivalence ratio of approximately 1.0. (An equivalence ratio of 1.0 indicates a stoichiometric ratio of fuel and air. Equivalence ratios below 1.0 indicate fuel-lean conditions, and ratios above 1.0 indicate fuel-rich conditions.) With lean combustion, the additional excess air cools the flame, which reduces the peak flame temperature and reduces the rate of thermal NO_x formation.³⁴

In all gas turbine combustor designs, the high-temperature combustion gases are cooled with dilution air to an acceptable temperature prior to entering the turbine. This dilution air rapidly cools the hot gases to temperatures below those required for thermal NO_x formation. With reduced residence time combustors, dilution air is added sooner than with standard combustors. Because the combustion gases are at a high temperature for a shorter time, the amount of thermal NO_x formed decreases.³⁴

Shortening the residence time of the combustion products at high temperatures may result in increased CO and HC emissions if

no other changes are made in the combustor. In order to avoid increases in CO and HC emissions, combustors with reduced residence time also incorporate design changes in the air distribution ports to promote turbulence, which improves fuel/air mixing and reduces the time required for the combustion process to be completed. These designs may also incorporate fuel/air premixing chambers. Therefore, the differences between reduced residence time combustors and standard combustors are the placement of the air ports, the design of the circulation flow patterns in the combustor, and a shorter combustor length.³⁴

5.2.1.2 Applicability. Lean primary zone combustion and reduced residence time combustion have been applied to annular, can-annular, and silo combustor designs.³⁵⁻³⁷ Almost all gas turbines presently being manufactured incorporate lean combustion and/or reduced residence time to some extent in their combustor designs, incorporating these features into production models since 1975.^{38,39} However, the varying uncontrolled NO_x emission levels of gas turbines shown in Figures 5-2 and 5-3 indicate that these controls are not incorporated to the same degree in every gas turbine and may be limited in some turbines by the quantity of dilution air available for lean combustion.

Lean primary zone and reduced residence time are most applicable to low-nitrogen fuels, such as natural gas and distillate oil fuels. These modifications are not effective in reducing fuel NO_x.⁴⁰

5.2.1.3 Factors Affecting Performance. For a given combustor, the performance of lean combustion is directly affected by the primary zone equivalence ratio. As shown in Figure 4-2, the further the equivalence ratio is reduced below 1.0, the greater the reduction in NO_x emissions. However, if the equivalence ratio is reduced too far, CO emissions increase and flame stability problems occur.⁴¹ This emissions tradeoff effectively limits the amount of NO_x reduction that can be achieved by lean combustion alone.

For combustors with reduced residence time, the amount of NO_x emission reduction achieved is directly related to the decrease in residence time in the high-temperature flame zone.

5.2.1.4 Achievable NO_x Emission Levels Using Lean Combustion and Reduced Residence Time Combustors. Lean combustion reduces NO_x emissions, and when used in combination with reduced residence time, NO_x emissions are further reduced. Figure 5-1

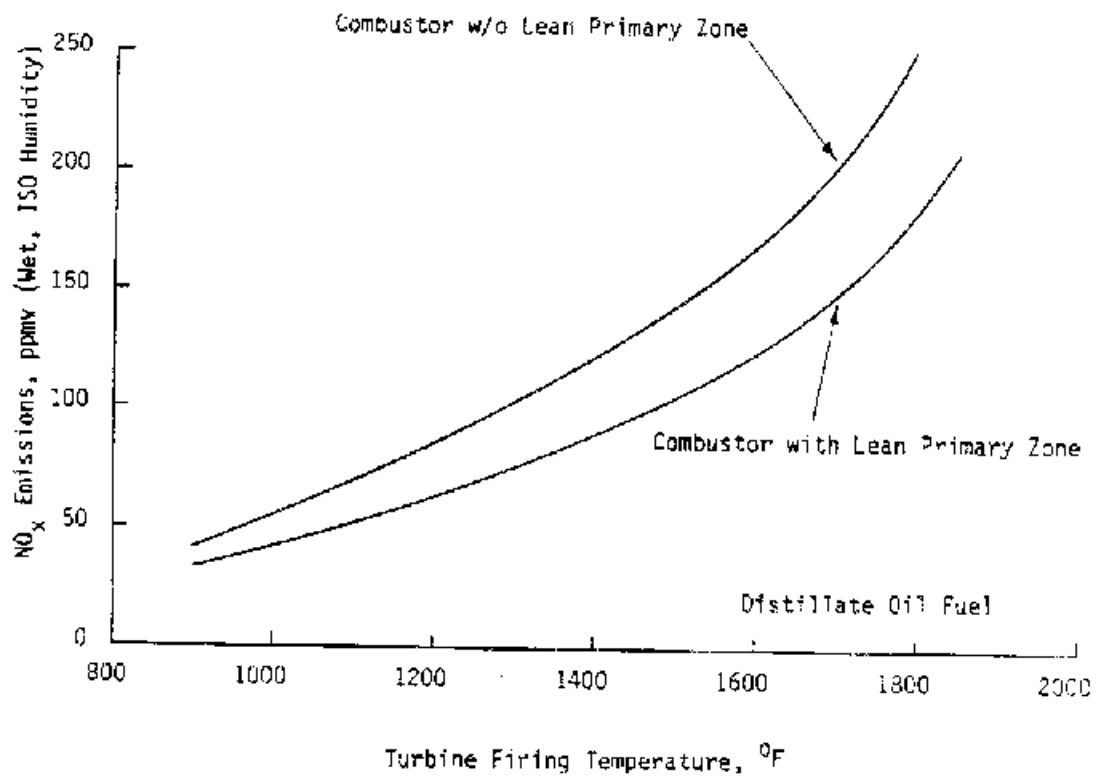


Figure 5-15. Nitrogen oxide emissions versus turbine firing temperature for combustors with and without a lean primary zone.⁴²

5 shows a comparison of NO_x emissions from a combustor with a lean primary zone and NO_x emissions from the same combustor without a lean primary zone. At the same firing temperature, NO_x emissions reductions of up to 30 percent are achieved using lean primary zone combustion without increasing CO emissions. Reducing the residence time at elevated temperatures reduces NO_x emissions. One test at 1065°C (1950°F) yielded a reduction in NO_x emissions of 40 percent by reducing the residence time. Carbon monoxide emissions increased from less than 10 to approximately 30 ppm.⁴²⁻⁴⁵

5.2.2 Lean Premixed Combustors

5.2.2.1 Process Description. In a conventional combustor, the fuel and air are introduced directly into the combustion zone and fuel/air mixing and combustion take place simultaneously. Wide variations in the air-to-fuel ratio (A/F) exist, and combustion of localized fuel-rich pockets produces significant levels of NO_x emissions. In a lean premixed combustor design, the air and fuel is premixed at very lean A/F's prior to introduction into the combustion zone. The excess air in the lean mixture acts as a heat sink, which lowers combustion temperatures. Premixing results in a homogeneous mixture, which minimizes localized fuel-rich zones. The resultant uniform, fuel-lean mixture results in greatly reduced NO_x formation rates.¹⁷

To achieve NO_x levels below 50 ppmv, referenced to 15 percent O₂, the design A/F approaches the lean flammability limit. To stabilize the flame, ensure complete combustion, and minimize CO emissions, a pilot flame is incorporated into the combustor or burner design. In most designs, the relatively

small amount of air and fuel supplied to this pilot flame is not premixed and the A/F is nearly stoichiometric, so the pilot flame temperature is relatively high. As a result, NO_x emissions from the pilot flame are higher than from the lean premixed combustion.⁴⁶

Virtually all gas turbine manufacturers have implemented lean premixed combustion development programs. Three manufacturers' designs that are available in production turbines are described below.

The first design uses a can-annular combustor and is shown in Figure 5-16

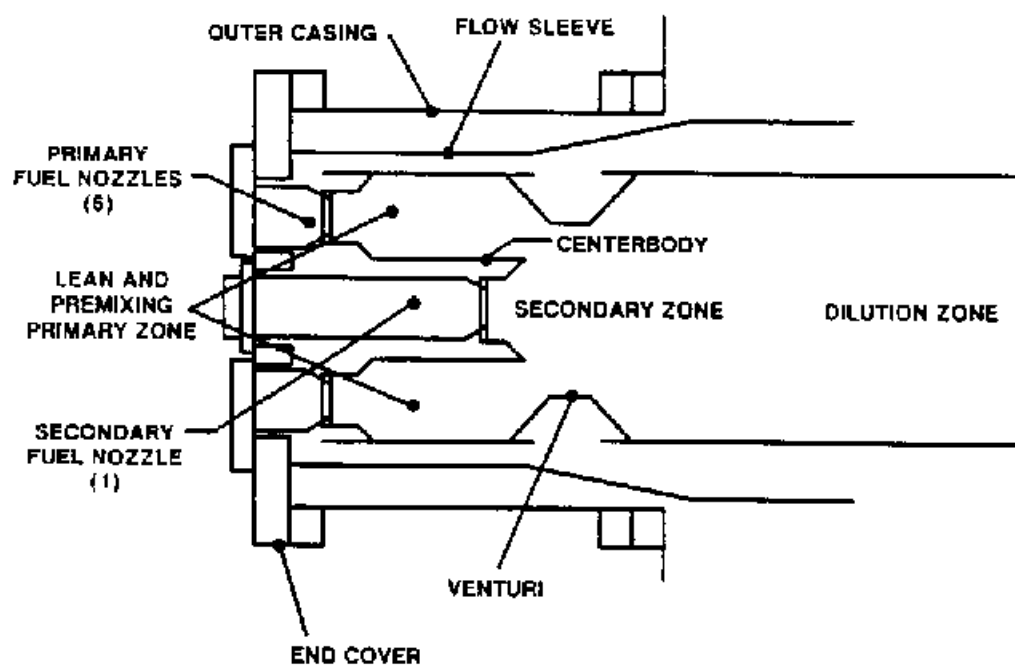


Figure 5-6. Cross-section of a lean premixed can-annular combustor.⁴⁷

. This is a two-stage premixed combustor: the first stage is the portion of the combustor upstream of the venturi section and includes the six primary fuel nozzles; the second stage is the balance of the combustor and includes the single secondary fuel nozzle.³³

The operating modes for this combustor design are shown in Figure 5-17. For ignition, warmup, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor.

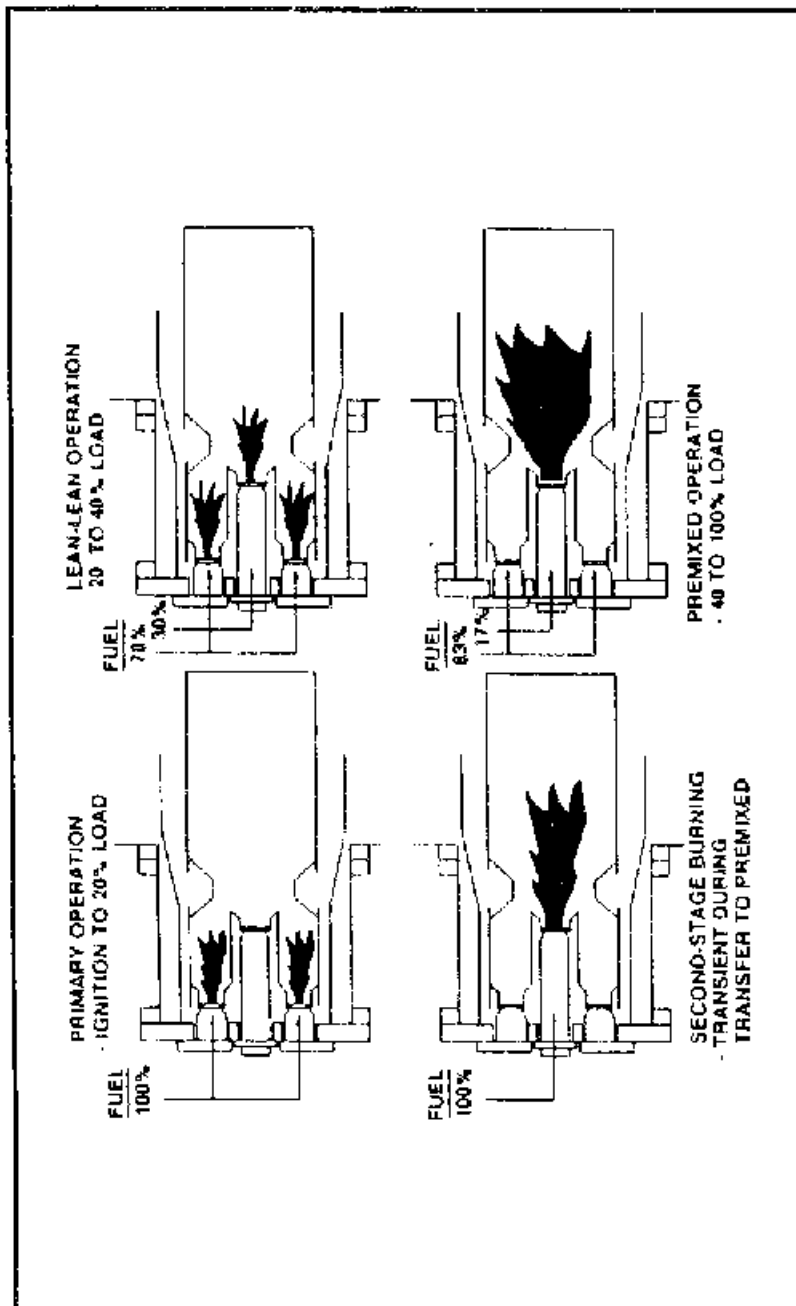


Figure 5-17. Operating modes for a lean premixed can-annular combustor.³³

Flame is present only in the first stage, and the equivalence ratio is kept as low as stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. Again, the equivalence ratio is kept as low as possible in both stages to minimize NO_x emissions. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.³³

For operation on distillate oil, fuel is introduced and burned only in the first stage for ignition and for loads up to approximately 50 percent. For loads greater than 50 percent, fuel is introduced and burned in both stages.³³

Figure 5-18 shows a lean premixed combustor design used by another manufacturer for an annular combustor.

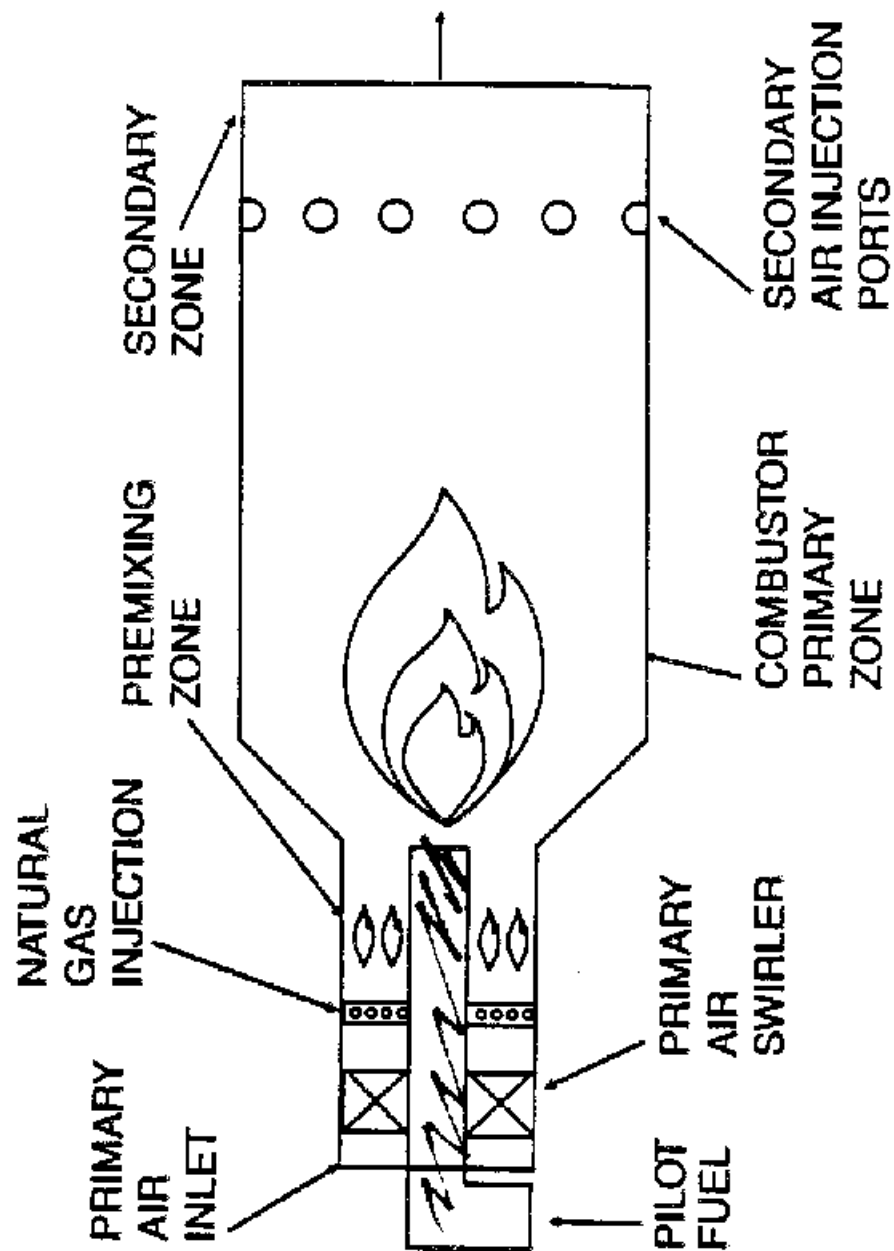


Figure 5-18. Cross-section of lean premixed annular combustion design.⁴⁷

The air and fuel are premixed using a very lean A/F, and the resultant uniform mixture is delivered to the primary combustion zone where combustion is stabilized using a pilot flame. Using one or more mechanical systems to regulate the airflow delivered to the combustor, the premix mode is operable for output loads between 50 and 100 percent. Below 50 percent load, only the pilot flame is operating, and NO_x emissions levels are similar to those for conventional combustors.⁴⁶

Another manufacturer's production low-NO_x design uses a silo combustor. Unlike the can-annular and annular designs, the silo combustor is mounted externally to the turbine and can therefore be modified without significantly affecting the rest of the turbine design, provided the mounting flange to the turbine is unchanged. In addition, this large combustion chamber is fitted with a ceramic lining that shields the metal surfaces from peak flame temperatures. This lining reduces the requirement for cooling air, so more air is available for the combustion process.¹⁷

This silo low-NO_x combustor design uses six burners, as shown in Figure 5-19

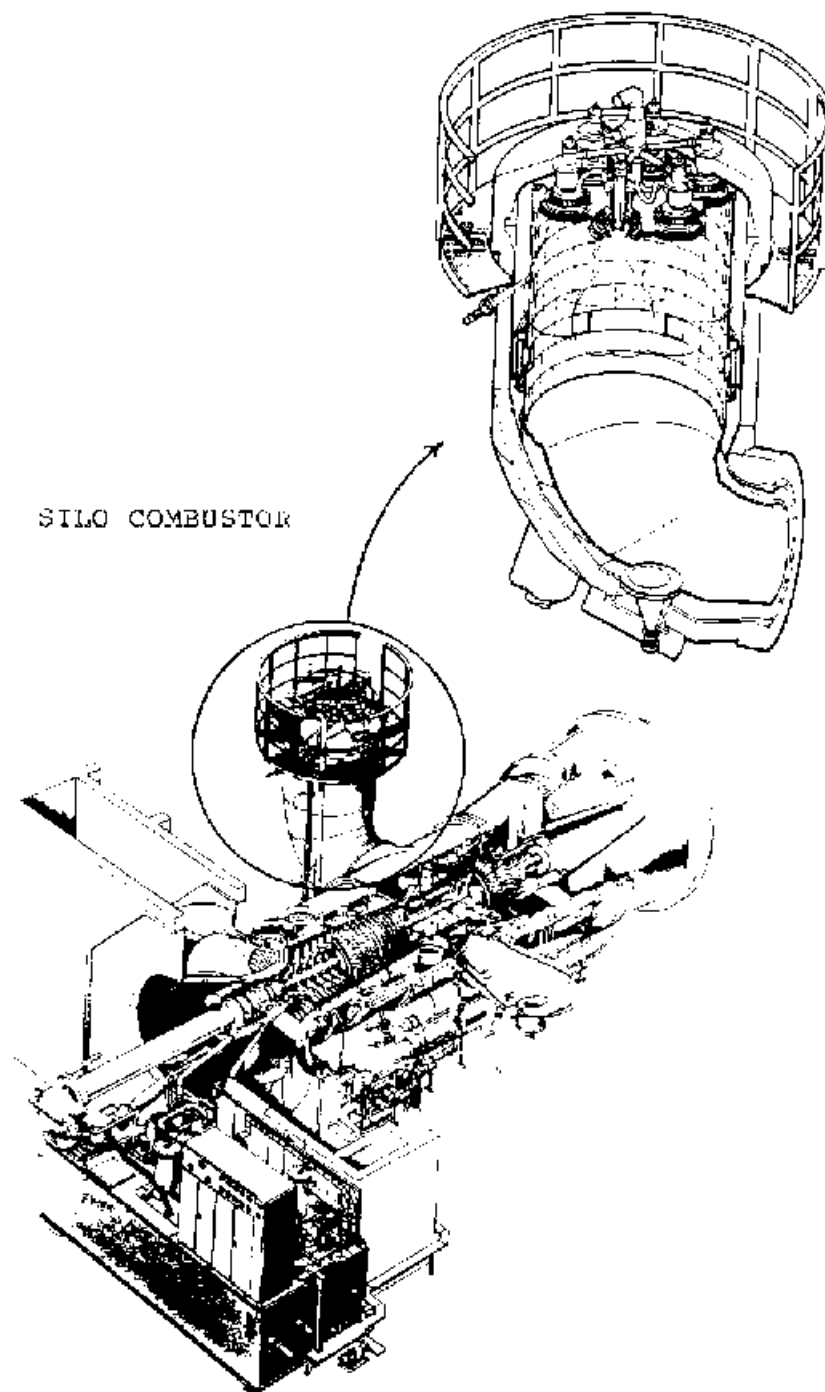


Figure 5-19. Cross-section of a low NO_x silo combustor.^{35,48}

. For operation on natural gas, each burner serves to premix the air and fuel to deliver a lean and uniform mixture to the combustion zone. To achieve the lowest possible NO_x emissions, the A/F of the premixed gases is kept very near the lean flammability limit and a pilot flame is used to stabilize the overall combustion process. This burner design is shown in Figure 5-20

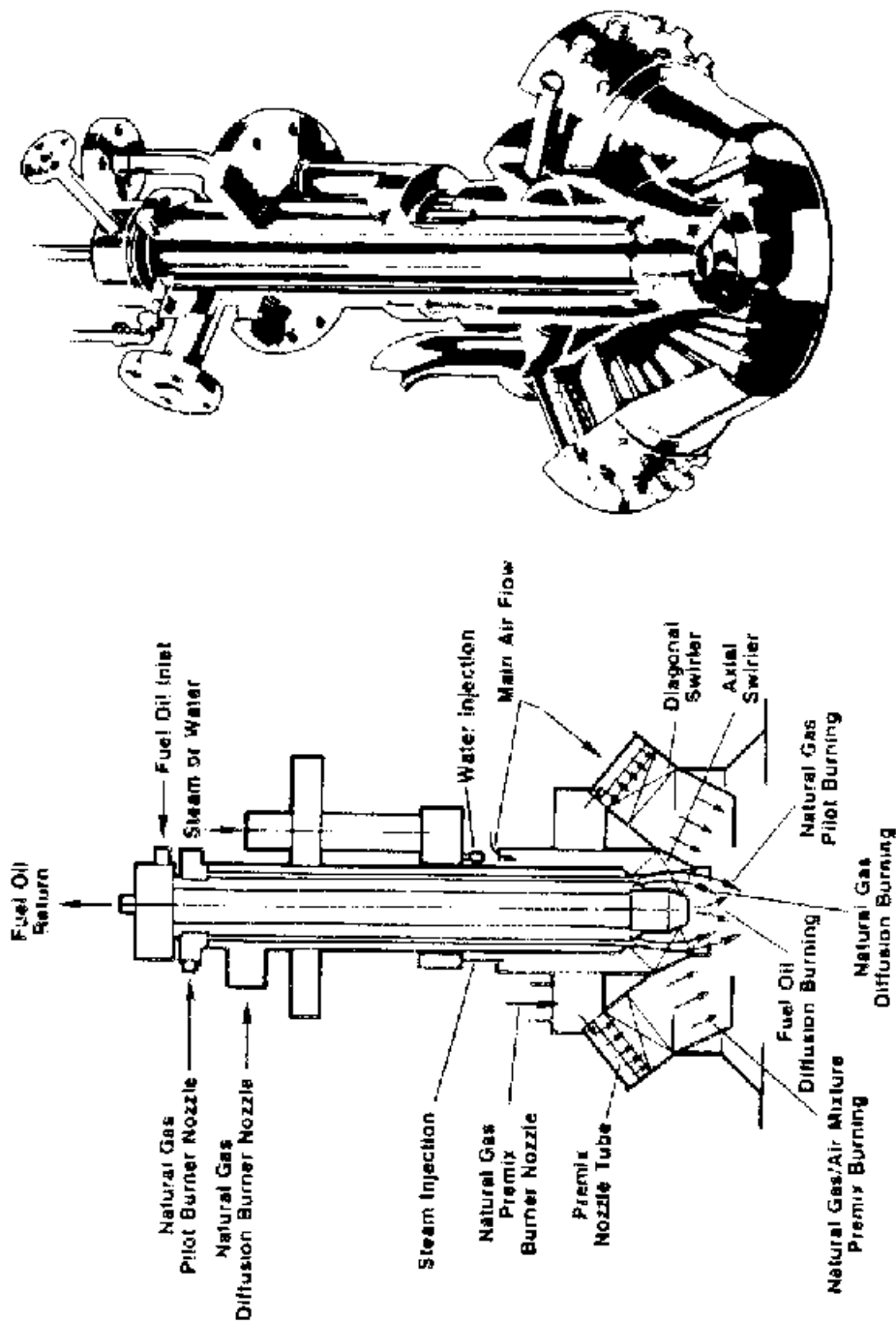


Figure 5-20. Low-NO_x burner for a silo combustor.⁴⁸

. Like the can-annular design, the burner in the silo combustor cannot operate over the full power range of the gas turbine in the premix mode due to inability of the premix mode to deliver suitable A/F's at low power output levels. For this reason, the burners are designed to operate in a conventional diffusion burning mode at startup and low power outputs and switch to a premix burning mode at higher power output levels.

For operation on distillate oil with the current burner design, combustion occurs only in a diffusion mode and there is no premixing of air and fuel.

5.2.2.2 Applicability. As discussed in Section 5.2.2.1, lean premixed combustors apply to can-annular, annular, and silo combustors. This combustion modification is effective in reducing thermal NO_x emissions for both natural gas and distillate oil but is not effective on fuel NO_x. Therefore, lean premixed combustion is not as effective in reducing NO_x levels if high-nitrogen fuels are fired.⁴⁹

The multiple operating modes associated with the percent operating load results in "stepped" NO_x emission levels. To date, low NO_x emission levels occur only at loads greater than 40 to 75 percent.

Lean premixed combustors currently are available for limited models from three manufacturers contacted for this study.^{6,17,24} Two additional manufacturers project an availability date of 1993 or 1994 for lean premixed combustors for some turbine models.^{11,50} All of these manufacturers state that these lean premixed combustors will be available for retrofit applications.

5.2.2.3 Factors Affecting Performance. The primary factors affecting the performance of lean, premixed combustors are A/F and the type of fuel. To achieve low NO_x emission levels, the A/F must be maintained in a narrow range near the lean flammability limit of the mixture. Lean premixed combustors are designed to maintain this A/F at rated load. At reduced load conditions, the fuel input requirement decreases. To avoid combustion instability and excessive CO emissions that would occur as the A/F reaches the lean flammability limit, all manufacturers' lean premixed combustors switch to a diffusion-type combustion mode at reduced load conditions, typically between 40 and 60 percent load. This switchover to a diffusion combustion mode results in higher NO_x emissions.

Natural gas produces lower NO_x levels than do oil fuels. The reasons for this are the lower flame temperature of natural gas and the ability to premix this fuel with air prior to

delivery into the second combustion stage. For operation on liquid fuels, currently available lean premixed combustor designs require water injection to achieve appreciable NO_x reduction.

5.2.2.4 Achievable NO_x Emission Levels. The achievable controlled NO_x emission levels for lean premixed combustors vary depending upon the manufacturer. At least three manufacturers currently guarantee NO_x emission levels of 25 ppmv, corrected to 15 percent O₂ for most or all of their gas turbines for operation on natural gas fuel without wet injection.^{6,17,24} Each of these three manufacturers has achieved controlled NO_x emission levels of less than 10 ppmv at one or more installations in the United States and/or Europe and guarantee this NO_x level for a limited number of their gas turbine models.⁵¹ All three manufacturers offer gas turbines in the 10+ MW (13,400 hp+) range and anticipate that guaranteed NO_x emission levels of 10 ppmv or less will be available for all of their gas turbines for operation on natural gas fuel in the next few years. These low-NO_x combustor designs apply to new turbines and existing installation retrofits.

For gas turbines in the range of 10 MW (13,400 hp) and under, one gas turbine manufacturer offers a guarantee for its lean premixed combustor, without wet injection, of 42 ppmv using natural gas fuel for two of its turbine models for 1994 delivery. This manufacturer states that a controlled NO_x emission level of 25 ppmv has been achieved by in-house testing, and this 25 ppmv level firing natural gas fuel is the goal for all of its gas turbine models, for both new equipment and retrofit applications.⁵⁰

These controlled NO_x emission levels of 9 to 42 ppmv correspond to full output load; at reduced loads, the NO_x levels increase, often in "stepped" fashion in accordance with changes in combustor operation from premixed mode to conventional or diffusion-mode operation (see Section 5.2.2.3). Figure 5-21

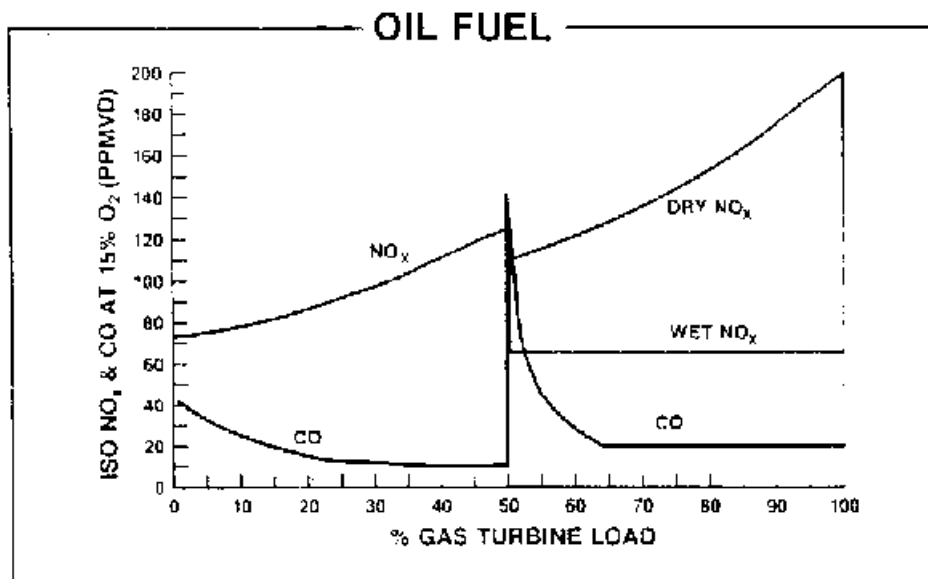
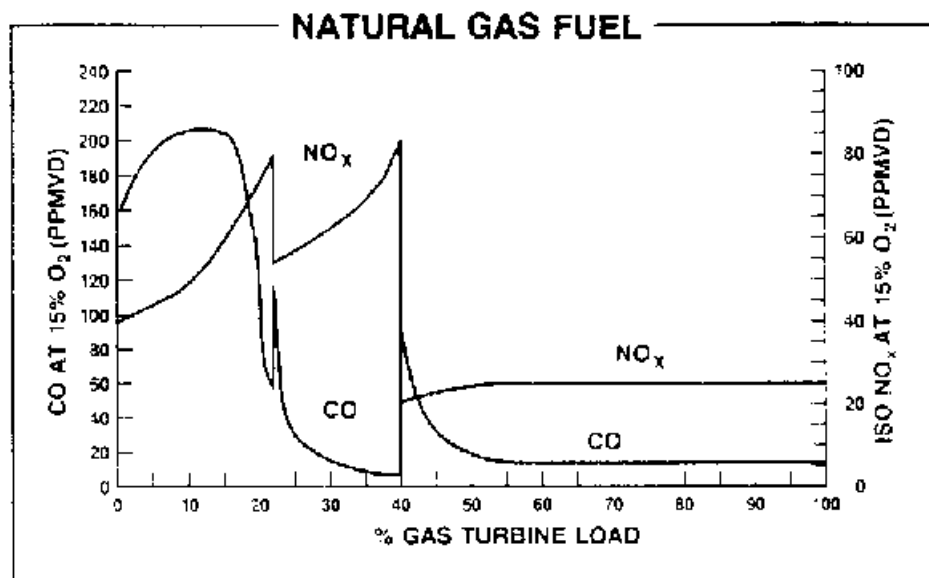


Figure 5-21. "Stepped" NO_x and CO emissions for a low-NO_x can-annular combustor burning natural gas and distillate oil fuels.⁴⁷

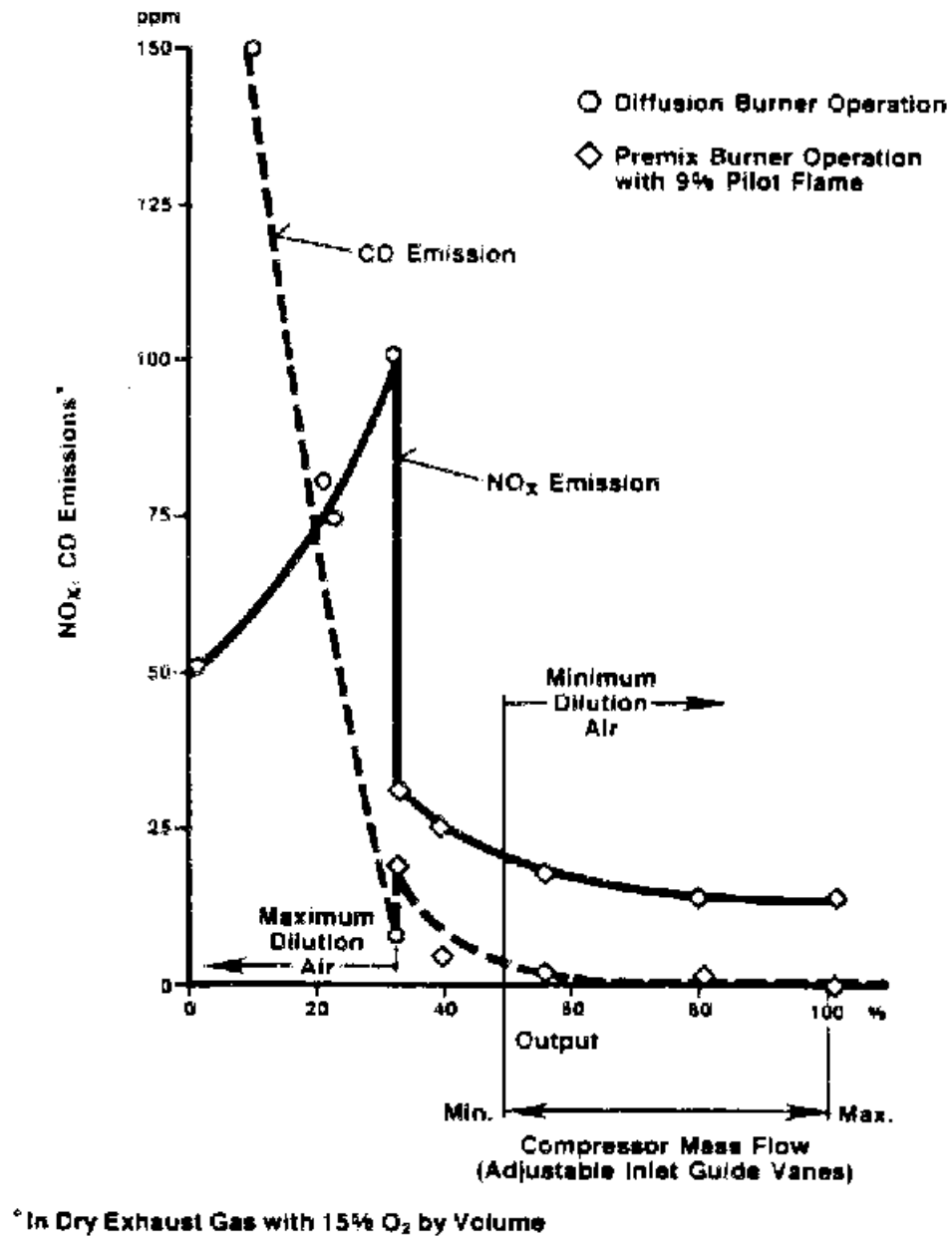
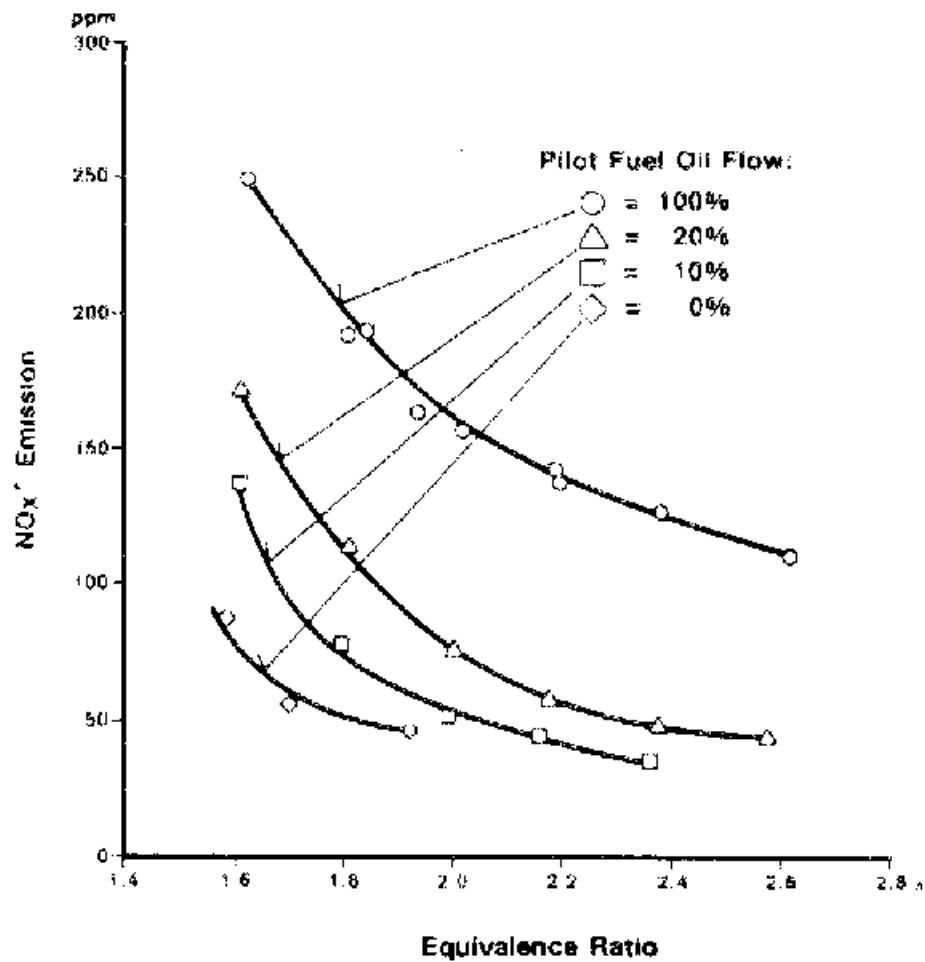


Figure 5-22. "Stepped" NO_x and CO emissions for a low-NO_x silo combustor burning natural gas.³⁵

shows these stepped NO_x emissions levels for a can-annular combustor for natural gas and oil fuel operation. Figure 5-22

shows the emissions for a silo combustor operating on natural gas only.



^a In Dry Exhaust Gas with 15% O₂ by Volume

Figure 5-23. Nitrogen oxide emission test results from a lean premix silo combustor firing fuel oil without wet injection.⁵³

The emission levels shown in Figures 5-21 and 5-22 correspond to full-scale production turbines currently available from the manufacturers.

Reduced NO_x emissions when burning oil fuel in currently available lean premixed combustor designs have been achieved only with water or steam injection. With water or steam injection, a 65 ppmv NO_x level can be achieved in the turbine with a can-annular combustor design; a 65 ppmv level can also be met with water injection in the turbine with a silo combustor at a WFR of 1.4.^{48,52} This 65 ppmv level for lean premixed combustors is higher than the controlled NO_x levels achieved with water injection in oil-fired turbines using a conventional combustor design.

Modification of the existing burner design used in the silo combustor to allow premixing of the oil fuel with air prior to combustion is under development. Tests performed using a 12 MW (16,200 hp) turbine achieved NO_x emission levels below 50 ppmv without wet injection, corrected to 15 percent O_2 , compared to uncontrolled levels of 150 ppmv or higher. The NO_x levels, without wet injection, as a function of equivalence ratio are shown in Figure 5-23. The design equivalence ratio at rated load is approximately 2.1. As shown in this figure, NO_x emissions below 50 ppmv were achieved at rated power output at pilot fuel flow levels of 10 percent of the total fuel input.⁵²

Site test data for two turbines using silo-type lean premixed combustors, as reported by the manufacturer, are shown in Table 5-12. As this table shows, NO_x emission levels as low as 16.5 ppmv were recorded for using natural gas fuel without

**TABLE 5-12. MEASURED NO_x EMISSIONS FOR COMPLIANCE TESTS
OF A NATURAL GAS-FUELED LEAN PREMIXED COMBUSTOR
WITHOUT WATER INJECTION²²**

Turbine No.	Output, percent of baseline	NO _x emission level, ppmv ^a
1	107	17.7
1	100	16.5
2	100	24.1
2	75	20.4
1	50	22.3
2	50	22.2

^aIn dry exhaust with 15 percent O₂, by volume.

water injection. Subsequent emission tests have achieved levels below 10 ppmv.⁵¹ Corresponding data for operation on oil fuel using only the pilot (diffusion) stage for combustion, and with water injection, is shown in Table 5-13. Levels of NO_x emissions

TABLE 5-13. MEASURED NO_x EMISSIONS FOR OPERATION OF A LEAN PREMIXED COMBUSTOR DESIGN OPERATING IN DIFFUSION MODE ON OIL FUEL WITH WATER INJECTION²²

Turbine No.	Output, percent of baseload	NO _x emission level, ppmv ^a
1	Peak	69.3
2	Peak	53.6
1	100	59.9
2	100	51.6
1	75	54.3
2	75	49.2
2	50	54.8

^aIn dry exhaust with 15 percent O₂, by volume.

at base load for No. 2 fuel oil are between 50 and 60 ppmv.

Based on information provided by turbine manufacturers, the potential NO_x reductions using currently available lean premixed

combustors are shown in Table 5-14. As this table indicates, NO_x emission reductions range from 14.7 tons/yr for a 1.1 MW (1,480 hp) turbine to 10,400 tons/yr

**TABLE 5-14. POTENTIAL NO_x REDUCTIONS FOR GAS TURBINES USING
LEAN PREMIXED COMBUSTORS**

Turbine model	Power output, MW	NO _x emissions					
		Uncontrolled		Controlled		NO _x reduction	
		Gas fuel, ppmv	Oil fuel, ppvm	Gas fuel, ppmv	Oil fuel, ppmv	Gas fuel, tons/yr ^a	Oil fuel, tons/yr ^{a b}
Saturn ^c	1.1	99	150	42	NA ^d	14.7	NA ^d
Centaur T-4500 ^c	3.3	130	179	42	NA ^d	59.5	NA ^d
Centaur "H" ^c	4.0	105	160	42	NA ^d	49.8	NA ^d
Taurus ^c	4.5	114	168	42	NA ^d	62.4	NA ^d
Mars T-12000 ^c	8.8	178	267	42	NA ^d	212	NA ^d
Mars T-14000 ^c	10.0	199	NA ^d	42	NA ^d	270	NA ^d
MS6001B	39.0	148	267	25/9 ^e	65	829/937	1,139
MS7001E	84.7	154	228	25/9 ^e	65	1,820/2,050	2,360
MS7001F	161	210	353	25	65	4,540	5,190
MS9001E	125	161	241	25/9 ^e	65	2,740/3,060	3,490
MS9001F	229	210	353	25	65	6,500	7,250
GT10	22.6	150	200	25	42	476	620
GT11N	83.3	390	560	25/9 ^e	42	5,070/5,290	7,360
V84.2	105	212	360	25/9 ^e	NA ^f	3,030/3,290	NA ^f
V94.2	153	212	360	9 ^e	NA ^f	4,410/4,780	NA ^f
V64.3	61.5	380	530	42	NA ^d	3,210	NA ^d
V84.3 ^c	141	380	530	42	NA ^d	7,230	NA ^d
V94.3 ^e	204	380	530	42	NA ^d	10,400	NA ^d

^aBased on 8,000 hours operation per year.

^bRequires water or steam injection.

^cScheduled availability is 1994 for natural gas fuel.

^dNA = Data not available.

^eStandard NO_x guarantee is 25 ppmv. Manufacturers offer guaranteed NO_x levels as low as 9 ppmv for these turbines.

^fScheduled availability 1993 for oil fuel without water injection. Reference 17.

for a 204 MW (274,000 hp) turbine for operation on natural gas without wet injection. Corresponding NO_x emission reductions for operation on oil fuel, with water injection, range from 620 tons/yr for a 22.6 MW (30,300 hp) turbine to 7,360 tons/yr for an 83.3 MW (112,000 hp) turbine.

Limited data from two manufacturers showing the impact of lean premixed combustor designs on CO emissions are shown in Table 5-15.

TABLE 5-15. COMPARISON OF NO_x AND CO EMISSIONS FOR STANDARD VERSUS LEAN PREMIXED COMBUSTORS FOR TWO MANUFACTURERS' TURBINES^{46, 54}

	Emissions, ppmv, referenced to 15 percent O ₂ ^a				
		Standard combustor		Lean premixed combustor	
GT Model	Power output, MW	NO _x	CO	NO _x	CO
Centaur H	4.0	105	15	25-42	50 ^b
Mars T-14000	10.0	199	5.5	25-42	50 ^b
MS6001B	39.0	148	10	9	25
MS7001E	84.7	154	10	9	25
MS9001E	125	161	10	9	25
MS7001F	161	210	25	25	15
MS9001F	229	210	25	25	15

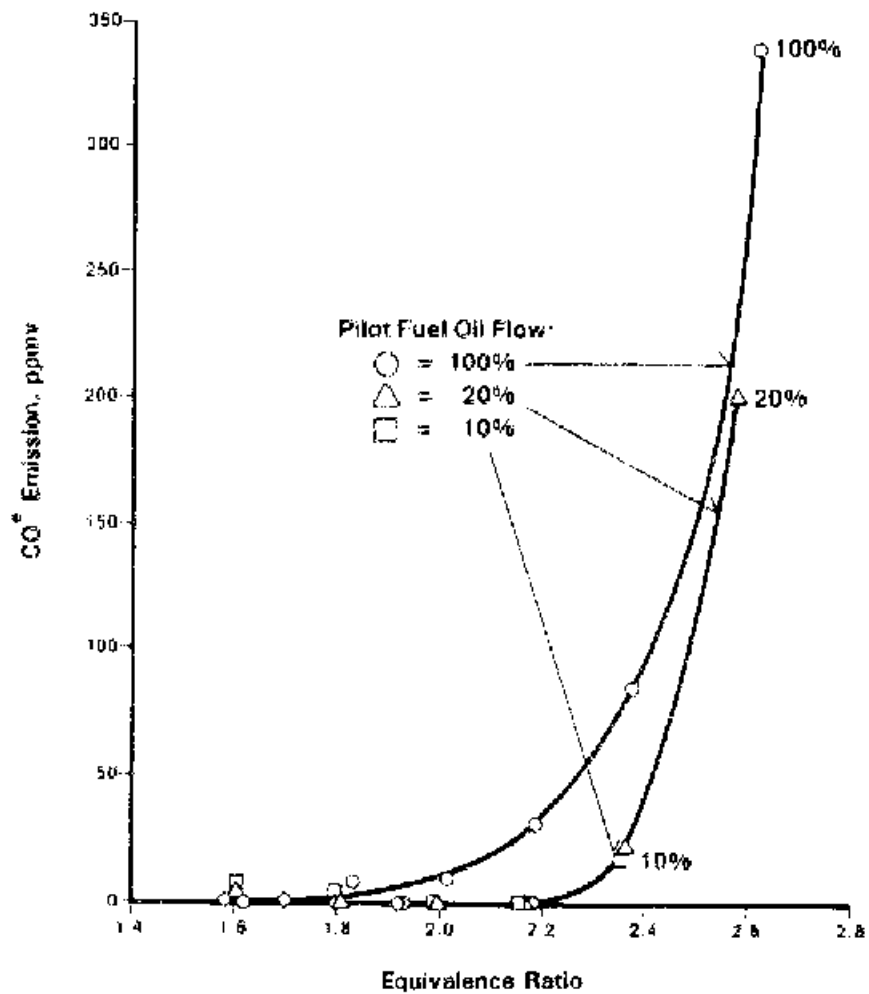
^aFor operation at ISO conditions using natural gas fuel.

^bMaximum design goal for CO emissions. Most in-house test configurations have achieved CO emission levels between 5 and 25 ppmv.

For natural gas-fueled turbines with rated outputs of 10 MW (13,400 hp) or less, controlled NO_x emission levels of 25 to 42 ppmv result in a rise in CO emission levels from 25 ppmv or less to as high as 50 ppmv.⁴³ For turbines above 10 MW (13,400 hp), controlled NO_x emission levels of 9 ppmv result in a rise in CO emissions from 10 to 25 ppmv for natural gas fuel. Conversely, for controlled NO_x emission levels of 25 ppmv, the CO emissions drop from 25 to 15 ppmv.⁵¹ For one manufacturer's lean premixed silo combustor design, CO emissions at rated load are less than 5 ppmv, as shown previously in Figure 5-21. This limited data suggest that the effect of lean premixed combustors on CO emissions depends upon the specific combustor design and the controlled NO_x emission level.

The emission levels shown in Table 5-15 correspond to rated power output. Like NO_x emission levels, CO emissions change with changes in combustor operating mode at reduced power output. The "stepped" effect on CO emissions is shown in Figures 5-21 and 5-22, shown previously.

Operation on oil fuel with wet injection, shown previously in Figure 5-21, shows CO emission levels of 20 ppmv. Additional CO emission data were not available for operation on oil fuel with water injection in lean premixed combustors. Developmental tests for operation on oil fuel without wet injection in a silo combustor are presented in Figure 5-24



^a In Dry Exhaust Gas with 15% O₂ by Volume

Figure 5-24. The CO emission test results from a lean premix silo combustor firing fuel oil without wet injection.

. At rated load, shown in this figure at an equivalence ratio of approximately 2.1, CO emissions are less than 10 ppmv, corrected to 15 percent O₂,

and are in the range of 0 to 2 ppmv for a pilot oil fuel flow of 10 percent (representing 10 percent of the total fuel flow).⁵³ This 10 percent pilot fuel flow corresponds to controlled NO_x emission levels below 50 ppmv, as shown previously in Figure 5-22. No data for HC emissions were available for lean premixed burner designs.

5.2.3 Rich/Quench/Lean Combustion

5.2.3.1 Process Description. Rich/quench/lean (RQL) combustors burn fuel-rich in the primary zone and fuel-lean in the secondary zone. Incomplete combustion under fuel-rich conditions in the primary zone produces an atmosphere with a high concentration of CO and hydrogen (H₂). The CO and H₂ replace some of the oxygen normally available for NO_x formation and also act as reducing agents for any NO_x formed in the primary zone. Thus, fuel nitrogen is released with minimal conversion to NO_x. The lower peak flame temperatures due to partial combustion also reduce the formation of thermal NO_x.⁵⁵

As the combustion products leave the primary zone, they pass through a low-residence-time quench zone where the combustion products are rapidly diluted with additional combustion air or water. This rapid dilution cools the combustion products and at the same time produces a lean A/F. Combustion is then completed under fuel-lean conditions. This secondary lean combustion step minimally contributes to the formation of fuel NO_x because most of the fuel nitrogen will have been converted to N₂ prior to the lean combustion phase. Thermal NO_x is minimized during lean combustion due to the low flame temperature.⁵⁵

5.2.3.2 Applicability. The RQL combustion concept applies to all types of gas turbines. None of the manufacturers contacted for this study, however, currently have this design available for their production turbines. This may be due to lack of demand for this design due to the current limited use of high-nitrogen-content fuels in gas turbines.

5.2.3.3 Factors Affecting Performance. The NO_x emissions from RQL combustors are affected primarily by the equivalence ratio in the primary combustion zone and the quench airflow rate.

Careful selection of equivalence ratios in the fuel-rich zone will minimize both thermal and fuel NO_x formation. Further NO_x reduction is achieved with increasing quench airflow rates, which serve to reduce the equivalence ratio in the secondary (lean) combustion stage.

5.2.3.4 Achievable NO_x Emissions Levels Using Rich/Quench/Lean Combustion. The RQL staged combustion has been demonstrated in rig tests to be effective in reducing both thermal NO_x and fuel NO_x. As shown in Figure 5-25, NO_x emissions are reduced by 40 to 50 percent in a test rig burning diesel fuel.

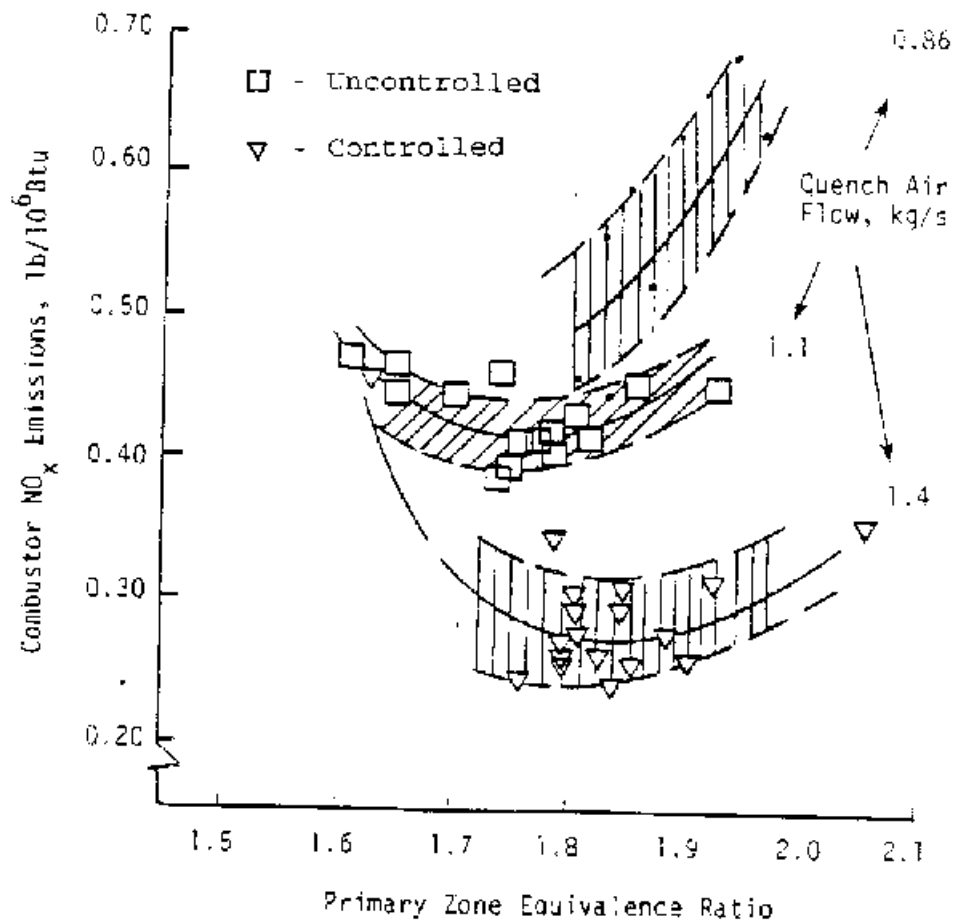


Figure 5-25. Nitrogen oxide emissions versus primary zone equivalence ratio for a rich/quench/lean combustor firing distillate oil.⁵⁶

At an equivalence ratio of 1.8, the NO_x emissions can be reduced from 0.50 to 0.27 lb/MMBtu by increasing the quench airflow from 0.86 to 1.4 kg/sec. Data were not available to convert the NO_x emissions figures to ppmv. The effectiveness of rich/lean staged combustion in reducing fuel NO_x when firing high-FBN fuels is shown in Figure 5-26.

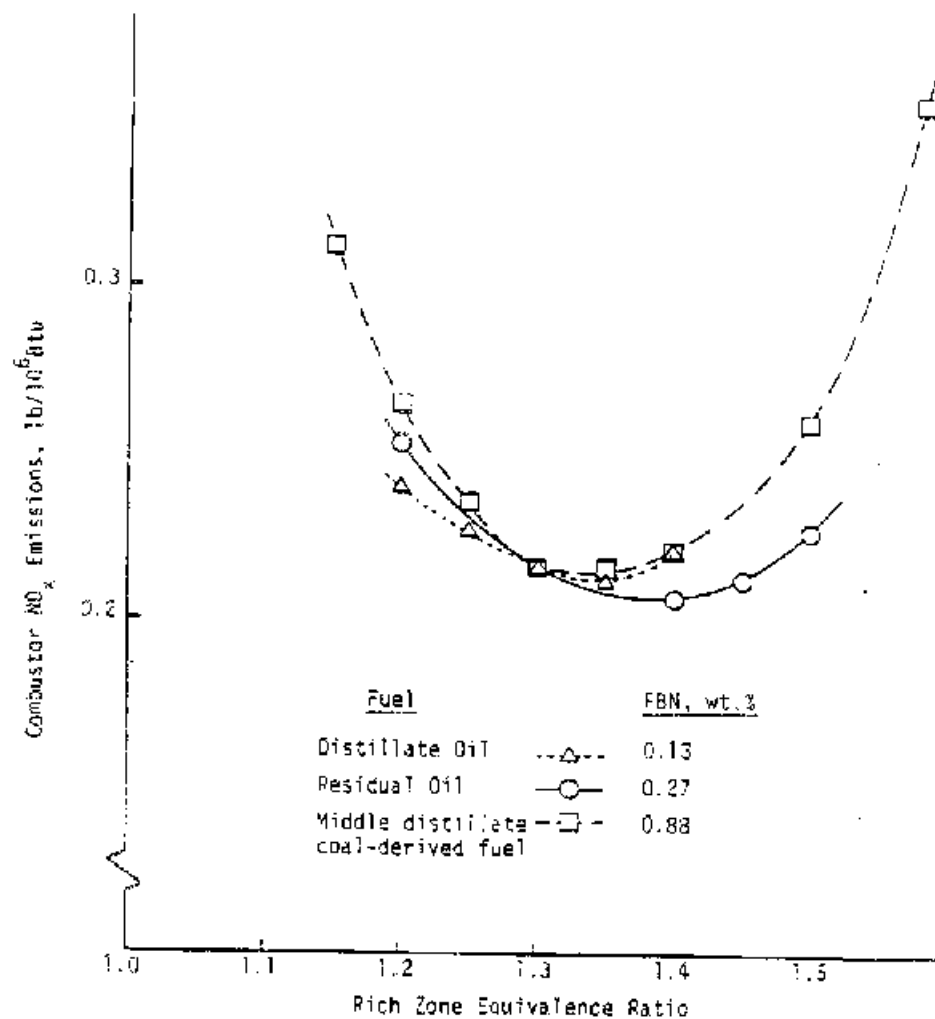


Figure 5-26. Effects of fuel bound nitrogen (FBN) content of NO_x emissions for a rich/quench/lean combustor.⁵⁷

Increasing the FBN content from 0.13 to 0.88 percent has little impact on the total NO_x formation at an operating equivalence ratio of 1.3 to 1.4. Tests on other rich/lean combustors indicate fuel nitrogen conversions to NO_x of about 7 to 20 percent.^{58, 59} These fuel nitrogen conversions represent a fuel NO_x emission reduction of approximately 50 to 80 percent.

One manufacturer has tested an RQL combustor design in a 4 MW (5,360 hp) gas turbine fueled with a finely ground coal and water mixture. The coal partially combusts in a fuel-rich zone at temperatures of 1650°C (3000°F), with low O₂ levels and an extremely short residence time. The partially combusted products are then rapidly quenched with water, cooling combustion temperatures to inhibit thermal NO_x formation. Additional combustion air is then introduced, and combustion is completed under fuel-lean conditions. In tests at the manufacturer's plant, cosponsored by the U. S. Department of Energy, a NO_x emission level of 25 ppmv at 15 percent O₂ was achieved. This combustor design can also be used with natural gas and oil fuels. Single-digit NO_x emission levels are reported for operation on

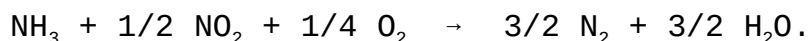
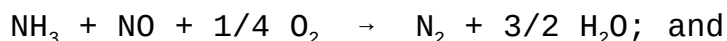
natural gas fuel. This combustor design is not yet available for production turbines.⁶⁰

5.3 SELECTIVE CATALYTIC REDUCTION

Selective catalytic reduction (SCR) is an add-on NO_x control technique that is placed in the exhaust stream following the gas turbine. Over 100 gas turbine installations use SCR in the United States.⁶¹ An SCR process description, the applicability of SCR for gas turbines, the factors affecting SCR performance, and the achievable NO_x reduction efficiencies are discussed in this section.

5.3.1 Process Description

The SCR process reduces NO_x emissions by injecting ammonia into the flue gas. The ammonia reacts with NO_x in the presence of a catalyst to form water and nitrogen. In the catalyst unit, the ammonia reacts with NO_x primarily by the following equations:⁶²



The catalyst's active surface is usually either a noble metal, base metal (titanium or vanadium) oxide, or a zeolite-based material. Metal-based catalysts are usually applied as a coating over a metal or ceramic substrate. Zeolite catalysts are typically a homogenous material that forms both the active surface and the substrate. The geometric configuration of the catalyst body is designed for maximum surface area and minimum obstruction of the flue gas flow path to maximize conversion efficiency and minimize back-pressure on the gas turbine. The most common catalyst body configuration is a monolith, "honeycomb" design, as shown in Figure 5-27.

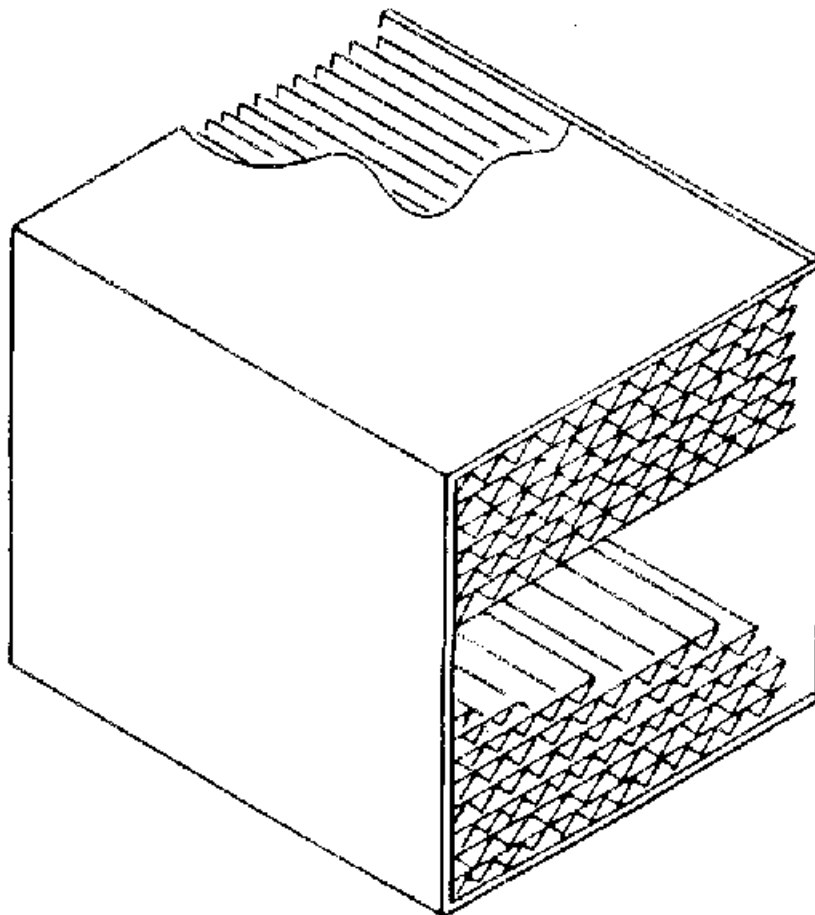


Figure 5-27. Cutaway view of a typical monolith catalyst body with honeycomb configuration.⁶²

An ammonia injection grid is located upstream of the catalyst body and is designed to disperse the ammonia uniformly throughout the exhaust flow before it enters the catalyst unit. In a typical ammonia injection system, anhydrous ammonia is drawn from a storage tank and evaporated using a steam- or electric-heated vaporizer. The vapor is mixed with a pressurized carrier gas to provide both sufficient momentum through the

injection nozzles and effective mixing of the ammonia with the flue gases. The carrier gas is usually compressed air or steam, and the ammonia concentration in the carrier gas is about 5 percent.⁶²

An alternative to using the anhydrous ammonia/carrier gas system is to inject an aqueous ammonia solution. This system is currently not as common but removes the potential safety hazards associated with transporting and storing anhydrous ammonia and is often used in installations with close proximity to populated areas.^{61,62}

The NH_3/NO_x ratio can be varied to achieve the desired level of NO_x reduction. As indicated by the chemical reaction equations listed above, it takes one mole of NH_3 to reduce one mole of NO , and two moles of NH_3 to reduce one mole of NO_2 . The NO_x composition in the flue gas from a gas turbine is over 85 percent NO , and SCR systems generally operate with a molar NH_3/NO_x ratio of approximately 1.0.⁶³ Increasing this ratio will further reduce NO_x emissions but will also result in increased unreacted ammonia passing through the catalyst and into the atmosphere. This unreacted ammonia is known as ammonia slip.

5.3.2 Applicability of SCR for Gas Turbines

Selective catalytic reduction applies to all gas turbine types and is equally effective in reducing both thermal and fuel NO_x emissions. There are, however, factors that may limit the applicability of SCR.

An important factor that affects the performance of SCR is operating temperature. Gas turbines that operate in simple cycle have exhaust gas temperatures ranging from approximately 450° to 540°C (850° to 1000°F). Base-metal catalysts have an operating temperature window for clean fuel applications of approximately 260° to 400°C (400° to 800°F). For sulfur-bearing fuels that produce greater than 1 ppm SO_3 in the flue gas, the catalyst operating temperature range narrows to 315° to 400°C (600° to 800°F). The upper range of this temperature window can be

increased using a zeolite catalyst to a maximum of 590°C (1100°F).⁶⁴

Base metal catalysts are most commonly used in gas turbine SCR applications, accounting for approximately 80 percent of all U.S. installations, and operate in cogeneration or combined cycle applications. The catalyst is installed within the HRSG, where the heat recovery process reduces exhaust gas temperatures to the proper operating range for the catalyst. The specific location of the SCR within the HRSG is application-specific; Figure 5-28 shows two possible SCR locations.

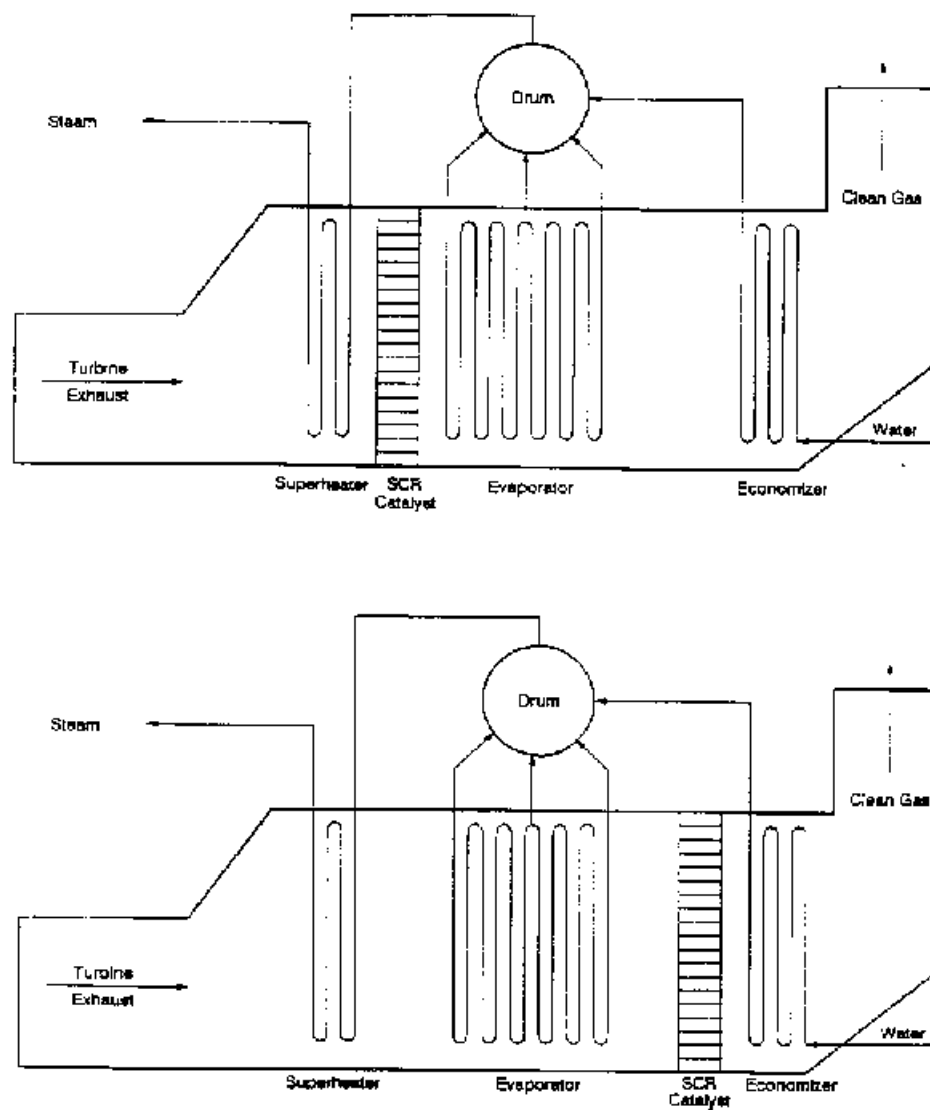


Figure 5-28. Possible locations for SCR unit in HRS_G.⁶²

In addition to the locations shown, the catalyst may also be located within the evaporator section of the HRSG.

As noted above, zeolite catalysts have a maximum operating temperature range of up to 590°C (1100°F), which is compatible with simple cycle turbine exhaust temperatures. To date, however, there is only one SCR installation operating with a zeolite catalyst directly downstream of the turbine. This catalyst, commissioned in December 1989, has an operating range of 260° to 515°C (500° to 960°F) and operates approximately 90 percent of the time at temperatures above 500°C (930°F).⁶⁵

Another consideration in determining the applicability of SCR is complications arising from sulfur-bearing fuels. The sulfur content in pipeline quality natural gas is negligible, but distillate and residual oils as well as some low-Btu fuel gases such as coal gas have sulfur contents that present problems when used with SCR systems. Combustion of sulfur-bearing fuels produces SO₂ and SO₃ emissions. A portion of the SO₂ oxidizes to SO₃ as it passes through the HRSG, and base metal catalysts have an SO₂-to-SO₃ oxidation rate of up to five percent.⁶⁴ In addition, oxidation catalysts, when used to reduce CO emissions, will also oxidize SO₂ to SO₃ at rates of up to 50 percent.⁶⁶

Unreacted ammonia passing through the catalyst reacts with SO₃ to form ammonium bisulfate (NH₄HSO₄) and ammonium sulfate [(NH₄)₂ SO₄] in the low-temperature section of the HRSG. The rate of ammonium salt formation increases with increasing levels of SO₃ and NH₃, and the formation rate increases with decreasing

temperature. Below 200°C (400°F), ammonium salt formation occurs with single-digit ppmv levels of SO₃ and NH₃.⁶⁶

The exhaust temperature exiting the HRSG is typically in the range of 150° to 175°C (300° to 350°F), so ammonium salt formation typically occurs in the low-temperature section of the HRSG.⁶⁶ Ammonium bisulfate is a sticky substance that over time corrodes the HRSG boiler tubes. Additionally, it deposits on both the boiler and catalyst bed surfaces, leading to fouling and plugging of these surfaces. These deposits result in increased back pressure on the turbine and reduced heat transfer efficiency in the HRSG. This requires that the HRSG be removed from service periodically to water-wash the affected surfaces. Ammonium sulfate is not corrosive, but like ammonium bisulfate, it deposits on the HRSG surfaces and contributes to plugging and fouling of the heat transfer system.³³

Formation of ammonium salts can be avoided by limiting the sulfur content of the fuel and/or limiting the ammonia slip. Low SO₂-to-SO₃ oxidizing catalysts are also available. Base metal catalysts are available with oxidation rates of less than 1 percent, but these low oxidation formulas also have lower NO_x reduction activity per unit volume and therefore require a greater catalyst volume to achieve a given NO_x reduction level. Zeolite catalysts are reported to have intrinsic SO₂-to-SO₃ oxidation rates of less than 1 percent.^{64,66} As stated above, pipeline-quality natural gas has negligible sulfur content, but some sources of natural gas contain H₂S, which may contribute to ammonium salt formation. For oil fuels, even the lowest-sulfur distillate oil or liquid aviation fuel contains sulfur levels that can produce ammonium salts. According to catalyst vendors, SCR systems can be designed for 90 percent NO_x reduction and 10 ppm or lower NH₃ slip for sulfur-bearing fuels up to 0.3 percent by weight.⁶⁴ Continuous emission monitoring equipment has been developed for NH₃, and may be instrumental in regulating ammonia injection to minimize slip.⁶⁷

To date, there is limited operating experience using SCR with oil-fired gas turbine installations. One combined cycle

installation using oil fuel, a United Airlines facility in San Francisco installed in 1985, experienced fuel-related catalyst problems and now uses only natural gas fuel.³³ In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now available, however, and catalyst formulation improvements have proven effective in resisting performance degradation with oil fuels in Europe and Japan, where catalyst life in excess of 4 to 6 years has been achieved, versus 8 to 10 years with natural gas fuel.⁶⁴ A zeolite catalyst installed on a 5 MW (6710 hp) dual fuel reciprocating engine in the northeastern United States has operated for over 3 years and burned approximately 600,000 gallons of diesel fuel while maintaining a NO_x reduction efficiency of greater than 90 percent.³

In its guidance to member states, NESCAUM recommends that SCR be considered for NO_x reduction in dual-fueled turbine applications. There are four combined cycle gas turbines installations operating with SCR in the northeast United States burning natural gas as the primary fuel with oil fuel as a back-up.³ These installations, listed in Table 5-16,

TABLE 5-16. GAS TURBINE INSTALLATIONS IN THE NORTHEASTERN UNITED STATES WITH SCR AND PERMITTED FOR BOTH NATURAL GAS AND OIL FUELS³

Installation	State	Gas turbine model	Output, MW ^a	NO _x emissions, ppmv (gas fuel/oil fuel)		
				Uncontrolled ^b	Wet injection ^b	Wet injection + SCR ^c
Altresco-Pittsfield	MA	MS6001	38.3	148/267	42/65	9/18 ^{d e}
Cogen Technologies	NJ	MS6001	38.3	148/267	42/65	15/65 ^f
Ocean State Power	RI	MS7001E	83.5	154/277	42/65	9/42 ^f
Pawtucket Power	RI	MS6001	38.3	148/267	42/65	9/18 ^d

^aPower output for a single gas turbine. Installation power output is higher due to multiple units and/or combined cycle operation.

^bPer manufacturer at ISO conditions.

^cOperating permit limits.

^dThis installation requires the SCR system to be operational when burning oil fuel.

^eThis installation operated 185 hours on oil fuel in 1991, burning approximately 354,000 gallons of oil fuel.

^fAmmonia injection is shut down during operation on oil fuel.

began operating recently and have limited hours of operation on oil fuel. As indicated in the table, two of these installations shut down the ammonia injection when operating on oil fuel to prevent potential operating problems arising from sulfur-bearing fuels. Permits issued more recently in this region for other dual-fuel installations, however, require that the SCR system be operational on either fuel.³

A final consideration for SCR is catalyst masking or poisoning agents. Natural gas is considered clean and free of contaminants, but other fuels may contain agents that can degrade catalyst performance. For refinery, field, or digester gas fuel applications, it is important to have an analysis of the fuel and properly design the catalyst for any identified contaminants. Arsenic, iron, and silica may be present in field gases, along with zinc and phosphorus. Catalyst life with these fuels depends upon the content of the gas and is a function of the initial

design parameters. With oil fuels, in addition to the potential for ammonium salt formation, it is important to be aware of heavy metal content. Particulates in the flue gas can also mask the catalyst.⁶⁴

Selective catalytic reduction may not be readily applicable to gas turbines firing fuels that produce high ash loadings or high levels of contaminants because these elements can lead to fouling and poisoning of the catalyst bed. However, because gas turbines are also subject to damage from these elements, fuels with high levels of ash or contaminants typically are not used.

Coal, while not currently a common fuel for turbines, has a number of potential catalyst deactivators. High dust concentrations, alkali, earth metals, alkaline heavy metals, calcium sulfate, and chlorides all can produce a masking or blinding effect on the catalyst. High dust can also erode the catalyst. Erosion commonly occurs only on the leading face of the catalyst. Airflow deflectors and dummy layers of catalyst can be used to straighten out the airflow and reduce erosion. There is currently no commercial U.S. experience with coal. In Japan, which burns low-sulfur coal with moderate dust levels, catalyst life has been 5 years or more without replacement. In Germany, with high dust loadings, the experience has also been 5 years or more.⁶⁴

Masking agents deposit on the surface of the catalyst, forming a barrier between the active catalyst surface and the exhaust gas, inhibiting catalytic activity. Poisoning agents chemically react with the catalyst and render the affected area inactive. Masking agents can be removed by vacuuming or by using soot blowers or superheated steam. Catalysts cleaned in this manner can recover greater than 90 percent of the original reduction activity. The effects of poisoning agents, however, are permanent and the affected catalyst surface cannot be regenerated.⁶⁴

Retrofit applications for SCR may require the addition of a heat exchanger for simple cycle installations, and replacement or extensive modification of the existing HRSG in cogeneration and

combined cycle applications to accommodate the catalyst body. For these reasons, retrofit applications for SCR could involve high capital costs.

5.3.3 Factors Affecting SCR Performance

The NO_x reduction efficiency for an SCR system is influenced by catalyst material and condition, reactor temperature, space velocity, and the NH₃/NO_x ratio.⁶³ These design and operating variables are discussed below.

Several catalyst materials are available, and each has an optimum NO_x removal efficiency range corresponding to a specific temperature range. Proprietary formulations containing titanium dioxide, vanadium pentoxide, platinum, or zeolite are available to meet a wide spectrum of operating temperatures. The NO_x removal efficiencies for these catalysts are typically between 80 and 90 percent when new. The NO_x removal efficiency gradually decreases over the operating life of the catalyst due to deterioration from masking, poisoning, or sintering.⁶³ The rate of catalyst performance degradation depends upon operating conditions and is therefore site-specific.

The space velocity (volumetric flue gas flow divided by the catalyst volume) is an indicator of gas residence time in the catalyst unit. The lower the space velocity, the higher the residence time, and the higher the potential for increased NO_x reduction. Because the gas flow is a constant determined by the gas turbine, the space velocity depends upon the catalyst volume, or total active surface area. The distance across the opening between plates or cells in the catalyst, referred to as the pitch, affects the overall size of the catalyst body. The smaller the pitch, the greater the number of rows or cells that can be placed in a given volume. Therefore, for a given catalyst body size, the smaller the pitch, the larger the catalyst volume and the lower the space velocity. For natural gas applications the catalyst pitch is typically 2.5 millimeters (mm) (0.10 inch [in.]), increasing to 5 to 7 mm (0.20 to 0.28 in.) for coal-fuel applications.⁶⁴

As discussed in Section 5.3.1, the NH_3/NO_x ratio can be varied to achieve the desired level of NO_x reduction. Increasing this ratio increases the level of NO_x reduction but may also result in higher ammonia slip levels.

5.3.4 Achievable NO_x Emission Reduction Efficiency Using SCR

Most SCR systems operating in the United States have a space velocity of about 30,000/hr, a NH_3/NO_x ratio of about 1.0, and ammonia slip levels of approximately 10 ppm. The resulting NO_x reduction efficiency is about 90 percent.⁴¹ Reduction efficiency is the level of NO_x removed as a percentage of the level of NO_x entering the SCR unit. Only one gas turbine installation in the United States was identified using only SCR to reduce NO_x emissions. This installation has two natural gas-fired 8.5 MW gas turbines, each with its own HRSG in which is installed an SCR system. A summary of emission testing at this site lists NO_x emissions at the inlet to the SCR catalyst at 130 ppmv. Controlled NO_x emissions downstream of the catalyst were 18 ppmv, indicating a NO_x reduction efficiency of 86 percent. Maximum ammonia slip levels were listed at 35 ppmv.⁶⁸

All other gas turbine installations identified as using SCR in the United States use this control method in combination with wet injection and/or low- NO_x combustors. The emission levels that can be achieved by this combination of controls are found in Section 5.4.

5.3.5 Disposal Considerations for SCR

The SCR catalyst material has a finite life, and disposal can pose a problem. The guaranteed catalyst life offered by catalyst suppliers ranges from 2 to 3 years.⁶⁴ In Japan, where SCR systems have been in operation since 1980, experience shows that many catalysts in operation with natural gas-fired boilers have performed well for 7 years or longer.^{63, 64} In any case, at some point the catalyst must be replaced, and those units containing heavy metal oxides such as vanadium or titanium potentially could be considered hazardous wastes. While the amount of hazardous material in the catalyst is relatively small, the volume of the catalyst body can be quite large, and disposal

of this waste could be costly. Some suppliers provide for the removal and disposal of spent catalyst. Precious metal and zeolite catalysts do not contain hazardous wastes.

5.4 CONTROLS USED IN COMBINATION WITH SCR

With but one exception, SCR units installed in the United States are used in combination with wet controls or combustion controls described in Sections 5.1 and 5.2. Wet controls yield NO_x emission levels of 25 to 42 ppmv for natural gas and 42 to 110 ppmv for distillate oil, based on the data provided by gas turbine manufacturers and shown in Figures 5-10 and 5-11. A carefully designed SCR system can achieve NO_x reduction efficiencies as high as 90 percent, with ammonia slip levels of 10 ppmv or less for natural gas and low-sulfur (<0.3 percent by weight) fuel applications.⁶⁴

As discussed for wet injection in Sections 5.1.4 and 5.2.2.4, controlled NO_x emission levels for natural gas range from 25 to 42 ppmv for natural gas fuel and from 42 to 110 ppmv for oil fuel. Applying a 90 percent reduction efficiency for SCR, NO_x levels can be theoretically reduced to 2.5 to 4.2 and 4.2 to 11.0 ppmv for natural gas and oil fuels, respectively. For oil fuels and other sulfur-bearing fuels, a reduction efficiency of 90 percent requires special design considerations to address potential operational problems caused by the sulfur content in the fuel. This subject is discussed in Section 5.3.2. The final controlled NO_x emission level depends upon the NO_x level exiting the turbine and the achievable SCR reduction efficiency.

Test reports provided by SCAQMD include three gas turbine combined cycle installations fired with natural gas that have achieved NO_x emission levels of 3.4 to 7.2 ppmv, referenced to 15 percent oxygen. The NO_x and CO emissions reported for these tests are shown in Table 5-17

TABLE 5-17. EMISSIONS TESTS RESULTS FOR GAS TURBINES USING STEAM INJECTION PLUS SCR⁶⁹⁻⁷¹

				NO _x emissions, ppmv (lb/hr)			
Test No.	Gas turbine model	Output, MW	Fuel	Uncontrolled	Wet injection	Wet injection + SCR	CO, ppmv
1	MS7001E	82.8	Natural gas + refinery gas mixture	154	42	5.66 (25.2)	<2.00
2	MS7001E	79.7	Natural gas + refinery gas + butane mixture	148	42	7.17 (31.7)	<2.00
3	MS6001B	33.8	LPG + refinery gas mixture	148	42	3.36 (5.82)	<2.00

TABLE 5-18. SUMMARY OF SCR NO_x EMISSION REDUCTIONS AND AMMONIA SLIP LEVELS FOR NATURAL GAS-FIRED TURBINES⁶⁸

Site	Gas turbine		Power output, MW	SCR operating temperature, °F	Maximum permit level for injection, NH ₃ /NO _x molar ratio	NO emissions, ppmv at 15% O ₂			Compliance test NH ₃ slip, ppmv at 15% O ₂ ^a
	Manufacturer	Model				SCR in	SCR out	Percent reduction	
A	GE	LM2500	22	730	1.0	50	9.0	82	10
B	GE	MS5001	18	645	1.0	45	4.5	90	2
C	GE	LM2500	22	685	1.1	37	8.9	76	20
D	ABB	Type 8	44	760	1.2	27	4	85	9
E	GE	LM2500	22	680	1.0	60	12.6	79	7
F	GE	MS7001E	80	630	1.0	28	8.4	70	4.1
G	GE	LM2500	22	625	0.9	68	13.6	80	1
H	Allison	501-KB	3.5	650	1.1	25	1.0	96	10
I	Solar	Mars	8.5	580	1.6	130	18.2	86	35
J	GE	LM2500	22	750	1.0	37	14.8	60	11
K	GE	MS7001E	80	754	1.0	40	6.0	85	2
L	GE	MS6001	37	650	1.0	47	8.9	81	4
M	GE	MS6001	37	700	NA	33	3.3	90	8

Ammonia slip levels were not reported. Ammonia slip levels

^aCalculated from ppmv entering the SCR and percent reduction figures.

^bNH₃ permit limit. Test emission level not available.

^cTest was run at less than permit NH₃/NO_x ratio of 1.1. SCR designed for exhaust from total of 5 turbines. Only one turbine operating during test.

^dThis site does not use wet injection for gas turbine NO_x reduction.

^eNH₃ compliance test not required. NH₃ level from NH₃ monitor testing.

were reported, however, in a summary of emission tests for 13 SCR installations and are presented in Table 5-18.⁶⁸ For these sites, operating on natural gas fuel, the NO_x reduction efficiency of the catalyst ranges

from 60 to 96 percent, with most reduction efficiencies between 80 and 90 percent. Ammonia slip levels range from 1 to 35 ppmv. The site with the 35 ppmv ammonia slip level is unique in that it is the only site identified in the United States that uses only SCR rather than a combination of SCR and wet injection to reduce NO_x emissions. With the exception of this site, all NH₃ slip levels in Table 5-18 that are based on test data are less than 10 ppmv. Based on information received from catalyst vendors, it is expected that an SCR system operating downstream of a gas turbine without wet injection could be designed to limit ammonia slip levels to 10 ppmv or less.⁶⁴ No test data are available for SCR operation on gas turbines fired with distillate oil fuels.

5.5 EFFECT OF ADDING A DUCT BURNER IN HRSG APPLICATIONS

A duct burner is often added in cogeneration and combined cycle applications to increase the steam capacity of the HRSG (see Section 4.2.2). Duct burners in gas turbine exhaust streams consist of pipes or small burners that are placed in the exhaust gas stream to allow firing of additional fuel, usually natural gas. Duct burners can raise gas turbine exhaust temperatures to 1000°C (2000°F), but a more common temperature is 760°C (1400°F). The gas turbine exhaust is the source of oxygen for the duct burner.

Figure 5-29 shows a typical natural gas-fired duct burner

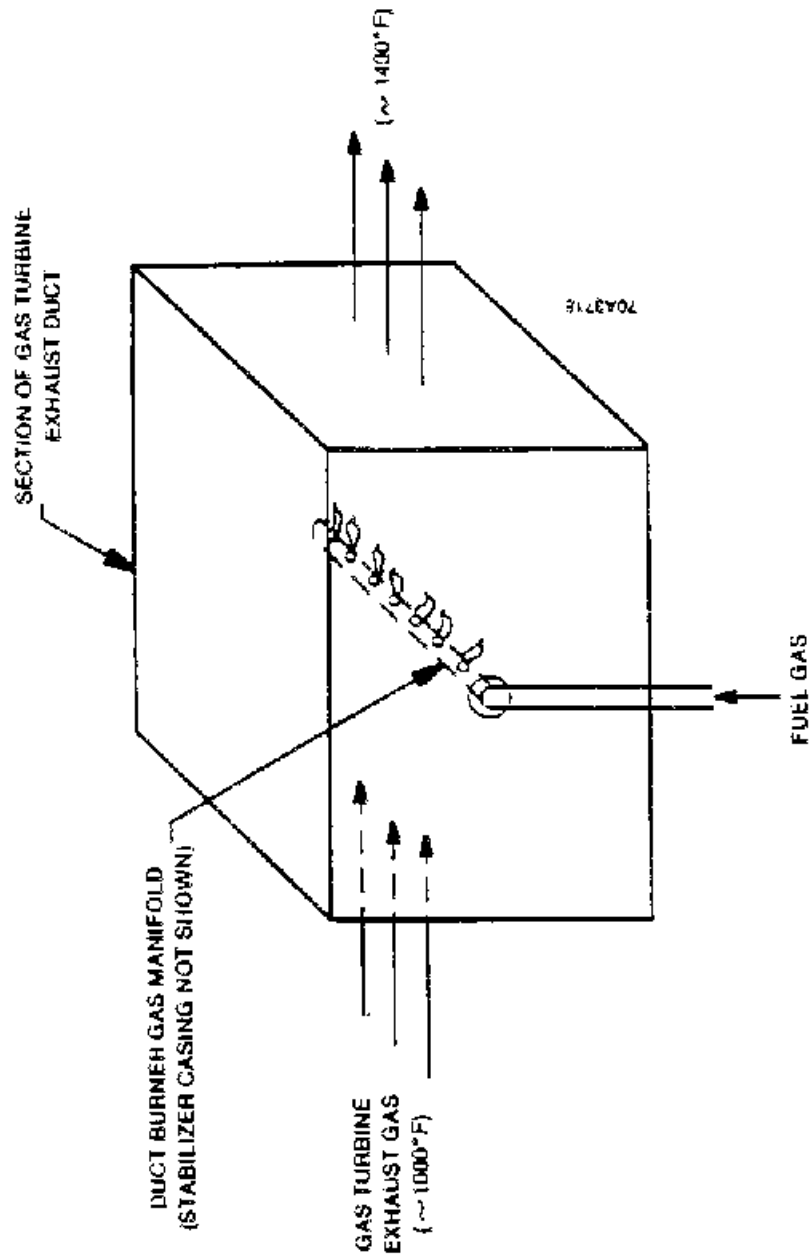


Figure 5-29. Typical duct burner for gas turbine exhaust application.⁷²

installation. Figure 5-30 is a cross-sectional view of one style

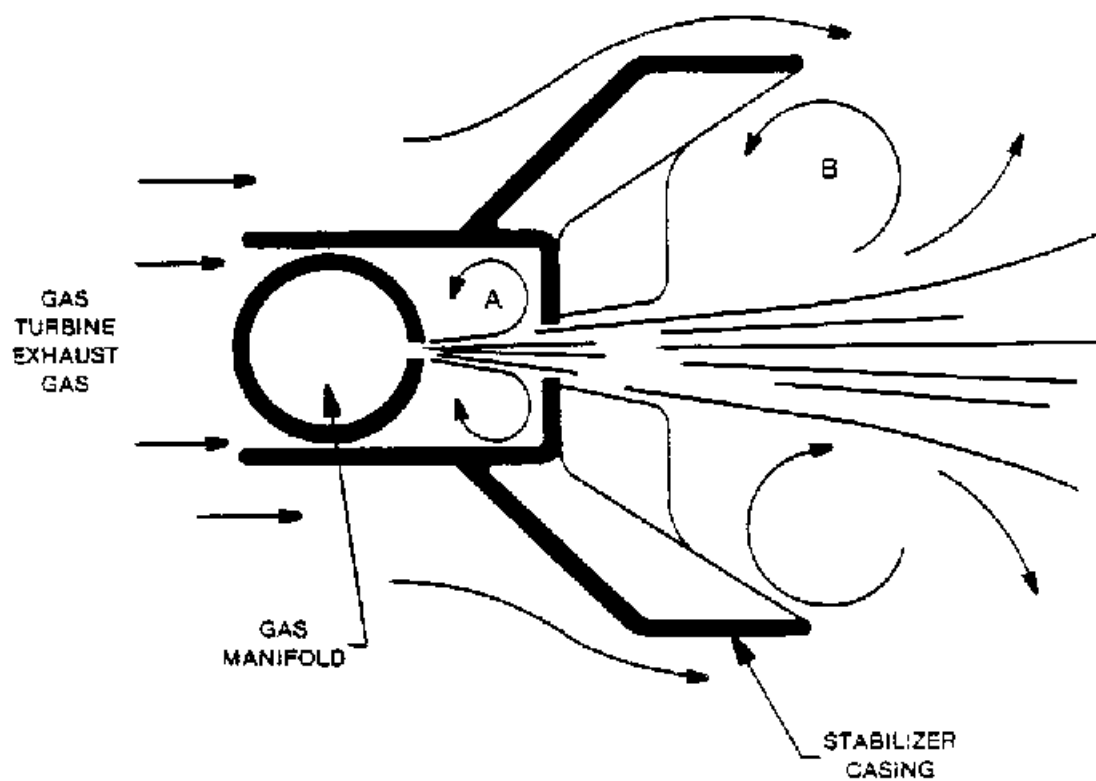


Figure 5-30. Cross-sectional view of a low-NO_x duct burner.^{73,74}

of duct burner that incorporates design features to reduce NO_x . In this low- NO_x design, natural gas exits the orifice in the manifold and mixes with the gas turbine exhaust entering through a small slot between the casing and the gas manifold. This mixture forms a jet diffusion flame that causes the recirculation shown in Zone "A." Due to the limited amount of turbine exhaust that can enter Zone A, combustion in this zone is fuel-rich. As the burning gas jet exits into Zone "B," it mixes with combustion products that are recirculated by the flow eddies behind the wings of the stabilizer casing. The flame then expands into the turbine exhaust gas stream, where combustion is completed.

For oil-fired burners, the design principles of the burner are the same. However, the physical layout is slightly different, as shown in

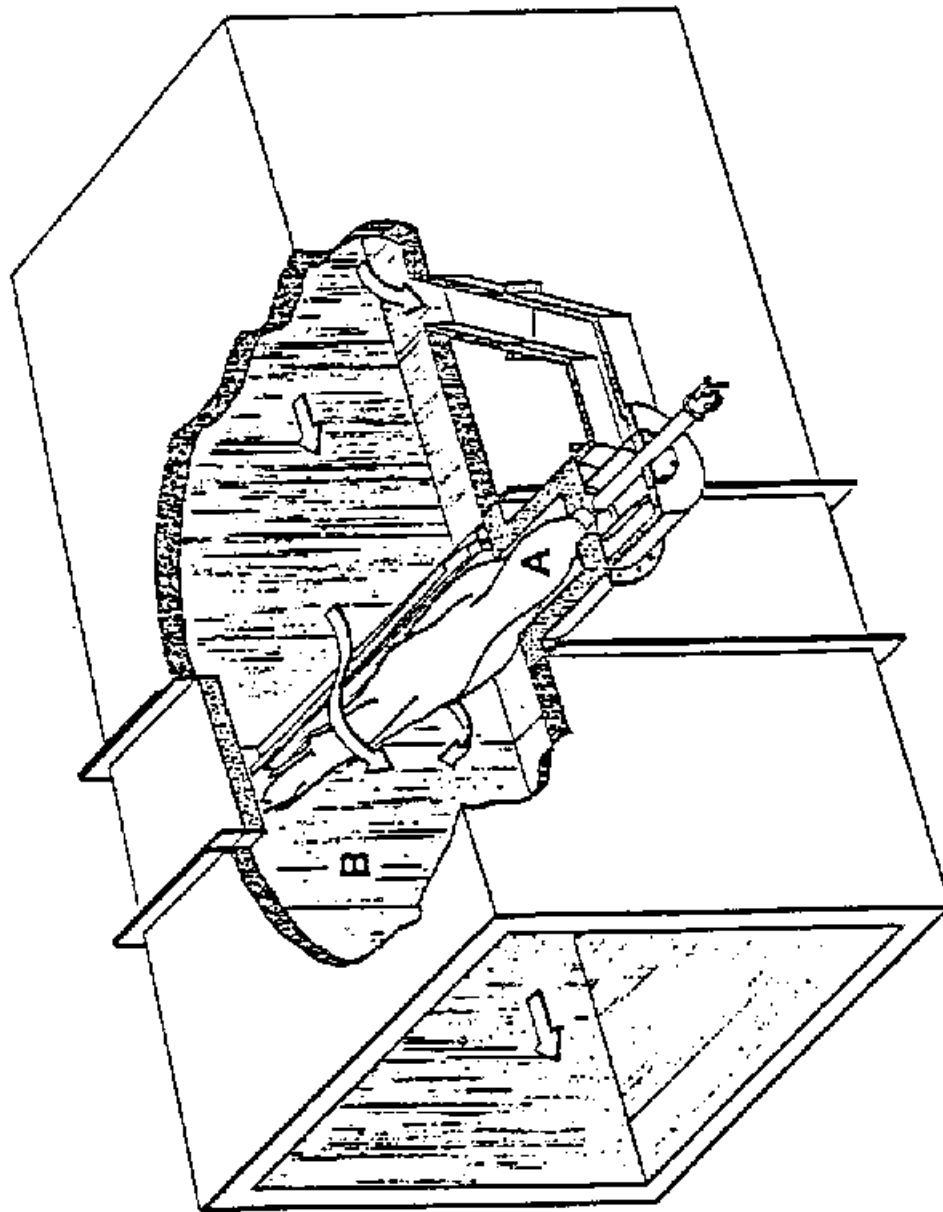


Figure 5-31. Low-NO_x duct burner designed for oil firing.^{73,75}

Figure 5-31. Turbine exhaust gas is supplied in substoichiometric quantities by a slip stream duct to the burner. This slip stream supplies the combustion air for the fuel-rich Zone A. The flame shield produces the flow eddies, which recirculate the combustion products into Zone B.⁷⁶

Most duct burners now in service fire natural gas. In all cases, a duct burner will produce a relatively small level of NO_x emissions during operation (See Section 4.2.2), but the net impact on total exhaust emissions (i.e., the gas turbine plus the duct burner) varies with operating conditions, and in some cases may even reduce the overall NO_x emissions. Table 5-19 shows the NO_x emissions measured at one site upstream and downstream of a duct burner. This table shows that NO_x emissions are reduced across the duct burner in five of the eight test runs.

TABLE 5-19. NO_x EMISSIONS MEASURED BEFORE AND AFTER A DUCT BURNER⁷⁷

Gas turbine operation parameters		Duct burner operating parameters		Duct burner inlet		Duct burner outlet		Change across duct burner	
Test No.	Load, MW	Steam/fuel injection ratio, lb/lb	Heat input, MM Btu/hr	Load, percent	NO _x , lb/MM Btu	NO, lb/hr	NO _x , lb/MM Btu	NO, lb/hr	NO _x , lb/MM Btu
1	33.8	0.94	133.8	82.1	0.149	61.4	0.097	55.7	-0.043
2	35.0	0.97	93.3	57.3	0.142	58.8	0.113	58.9	0.001
3	34.5	0.95	40.8	25.0	0.134	57.5	0.118	58.7	0.029
4	32.0	0.50	137.5	84.4	0.207	85.8	0.151	83.9	-0.014
5	32.8	0.46	43.8	26.8	0.228	95.2	0.192	94.0	-0.027
6	31.5	0.00	136.7	83.9	0.392	159.7	0.270	156.2	-0.026
7	33.0	0.00	42.0	25.8	0.384	166.7	0.313	156.7	-0.238
8	11.1	0.00	140.9	86.5	0.157	29.1	0.132	42.1	0.092
									13.0

The reason for this net NO_x reduction is not known, but it is believed to be a result of the reburning process in which the intermediate combustion products from the duct burner interact with the NO_x already present in the gas turbine exhaust. The manufacturer of the burner whose emission test results are shown in Table 5-19 states that the following conditions are necessary for reburning to occur:

1. The burner flame must produce a high temperature in a fuel-rich zone;
2. A portion of the turbine exhaust containing NO_x must be introduced into the localized fuel-rich zone with a residence time sufficient for the reburning process to convert the turbine NO_x to N₂ and O₂; and
3. The burner fuel should contain no FBN.⁷⁸

In general, sites using a high degree of supplementary firing have the highest potential for a significant amount of reburning. In practice, only a limited number of sites achieve these reburning conditions due to specific plant operating requirements.⁷⁸

5.6 ALTERNATE FUELS

Because thermal NO_x production is an exponential function of flame temperature (see Section 4.1.1), it follows that using fuels with flame temperatures lower than those of natural gas or distillate oils results in lower thermal NO_x emissions. Coal-derived gas and methanol have demonstrated lower NO_x emissions than more conventional natural gas or oil fuels. For applications using fuels with high FBN contents, switching to a fuel with a lower FBN content will reduce thermal NO_x formation and thereby lower total NO_x emissions.

5.6.1 Coal-Derived Gas

Combustor rig tests have demonstrated that burning coal-derived gas (coal gas) that has been treated to remove FBN produces approximately 30 percent of the NO_x emission levels experienced when burning natural gas. This is because coal gas has a low heat energy level of around 300 Btu or less, which results in a flame temperature lower than that of natural gas.⁷⁹ The cost associated with producing coal gas suitable for combustion in a gas turbine has made this alternative economically unattractive, but recent advances in coal gasification technology have renewed interest in this fuel.

A coal gas-fueled power plant is currently operating in the United States at a Dow Chemical plant in Plaquemine, Louisiana. This facility operates with a subsidy from the Federal Government, which compensates for the price difference between coal gas and conventional fuels. Several commercial projects have been recently announced using technology developed by Texaco, Shell, Dow Chemical, and the U.S. Department of Energy. Facilities have been permitted for construction in Massachusetts and Delaware.⁸⁰

A demonstration facility, known as Cool Water, operated using coal gas for 5 years in Southern California in the early 1980's. The NO_x emissions were reported at 0.07 lb/MMBtu.⁸⁰ Fuel analysis data is not available to convert this NO_x emission level to a ppmv figure. No other emissions data are available.

5.6.2 Methanol

Methanol has a flame temperature of 1925°C (3500°F) versus 2015°C (3660°F) for natural gas and greater than 2100°C (3800°F) for distillate oils. As a result, the NO_x emission levels when burning methanol are lower than those for either natural gas or distillate oils.

Table 5-20 presents NO_x emission data for a full-scale turbine firing methanol.

TABLE 5-20. NO_x EMISSIONS TEST DATA FOR A GAS TURBINE FIRING METHANOL AT BASELOAD^{a, 81}

Test	W/F ratio, lb/lb	NO _x emissions ISO conditions, ppm at 15% O ₂	NO _x reduction, percent ^b
A	0	41	0
B	0	45	0
C	0	48	0
D	0	49	0
E	0	60	0
F	0	47	0
G	0	53	0
H	0	48	0
I	0	51	0
J	0	52	0
K	0	41	0
L	0	47	0
M	0	48	0
AVERAGE		49	
N	0.11	28	42.2
O	0.23	17	65.2
P	0.23	18	62.7
Q	0.24	18	62.7

^aBaseload = 25 MW output

^bCalculated using the average of the uncontrolled emissions.

The NO_x emissions from firing methanol without water injection ranged from 41 to 60 ppmv and averaged 49 ppmv. This test also indicated that methanol increases turbine output due to the higher mass flows that result from methanol firing. Methanol firing increased CO and HC emissions slightly compared to the same turbine's firing distillate oil with water injection. All other aspects of turbine performance were as good when firing methanol as when the turbine fired natural gas or distillate oil.⁸² Turbine maintenance requirements were estimated to be lower and turbine life was estimated to be longer on methanol fuel than on distillate oil fuel because methanol produced fewer deposits in the combustor and power turbine.

Table 5-20 also presents NO_x emission data for methanol firing with water injection. At water-to-fuel ratios from 0.11 to 0.24, NO_x emissions when firing methanol range from 17 to 28 ppmv, a reduction of 42 to 65 percent.

In a study conducted at an existing 3.2 MW gas turbine installation in 1984, a gas turbine was modified to burn methanol. This study was conducted at the University of California at Davis and was sponsored by the California Energy Commission. A new fuel delivery system for methanol was required, but the only major modifications required for the turbine used in this study were new fuel manifolds and nozzles. Tests conducted burning methanol showed no visible smoke emissions, and only minor increases in CO emissions. Figure 5-32 shows the NO_x emissions measured while burning

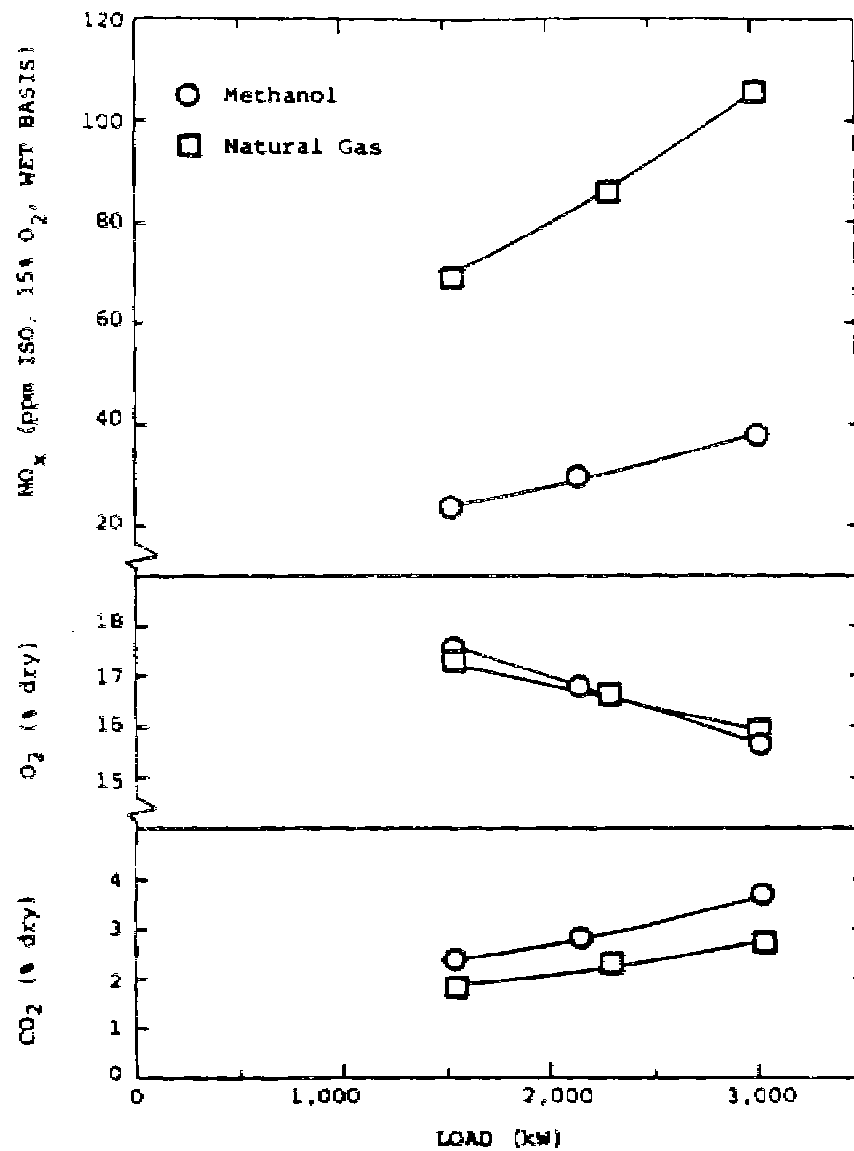


Figure 5-32. Influence of load on NO_x and CO₂ emissions for methanol and natural gas.⁸³

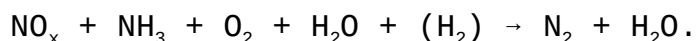
methanol and natural gas. Reductions of up to 65 percent were achieved, as NO_x emissions were 22 to 38 ppm when burning methanol versus

62 to 100 ppm for natural gas. In addition to the intrinsically lower NO_x production, water can be readily mixed with methanol prior to delivery to the turbine to obtain the additional NO_x reduction levels achievable with wet injection. Gas turbine performance characteristics, including startup, acceleration, load changes, and full load power, were all deemed acceptable by the turbine manufacturer.⁸³

The current economics of using methanol as a primary fuel are not attractive. There are no confirmed commercial methanol-fueled gas turbine installations in the United States.

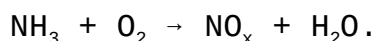
5.7 SELECTIVE NONCATALYTIC REDUCTION

Selective noncatalytic reduction (SNCR) is an add-on technology that reduces NO_x using ammonia or urea injection similar to SCR but operates at a higher temperature. At this higher operating temperature of 870° to 1200°C (1600° to 2200°F), the following reaction occurs:⁸⁴



This reaction occurs without requiring a catalyst, effectively reducing NO_x to nitrogen and water. The operating temperature can be lowered from 870°C (1600°F) to 700°C (1300°F) by injecting hydrogen (H₂) with the ammonia, as is shown in the above equation.

Above the upper temperature limit, the following reaction occurs:⁸⁴



Levels of NO_x emissions increase when injecting ammonia or urea into the flue gas at temperatures above the upper temperature limits of 1200°C (2200°F).

Since SNCR does not require a catalyst, this process is more attractive than SCR from an economic standpoint. The operating temperature window, however, is not compatible with gas turbine exhaust temperatures, which do not exceed 600°C (1100°F). Additionally, the residence time required for the reaction is approximately 100 milliseconds, which is relatively slow for gas turbine operating flow velocities.⁸⁵

It may be feasible, however, to initiate this reaction in the gas turbine where operating temperatures fall within the reaction window, if suitable gas turbine modifications and injection systems can be developed.⁸⁵ This control technology has not been applied to gas turbines to date.

5.8 CATALYTIC COMBUSTION

5.8.1 Process Description

In a catalytic combustor, fuel and air are premixed into a fuel-lean mixture (fuel/air ratio of approximately 0.02) and then pass into a catalyst bed. In the bed, the mixture oxidizes without forming a high-temperature flame front. Peak combustion temperatures can be limited to below 1540°C (2800°F), which is below the temperature at which significant amounts of thermal NO_x begin to form.⁸⁶ An example of a lean catalytic combustor is shown in Figure 5-33.

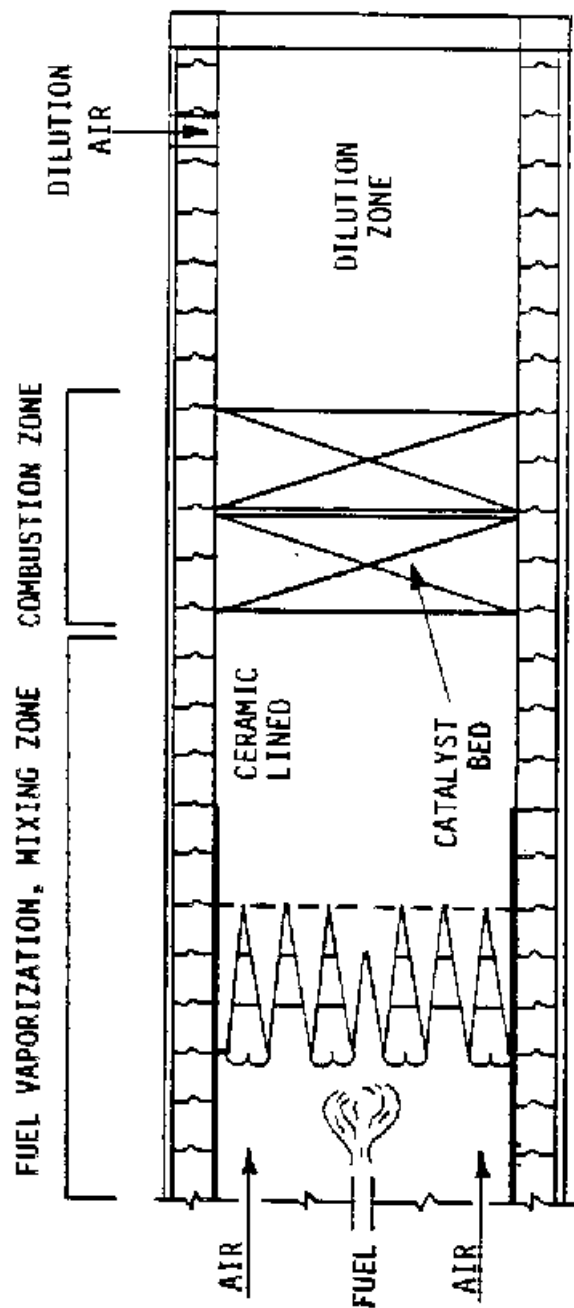


Figure 5-33. A lean catalytic combustor.⁸⁷

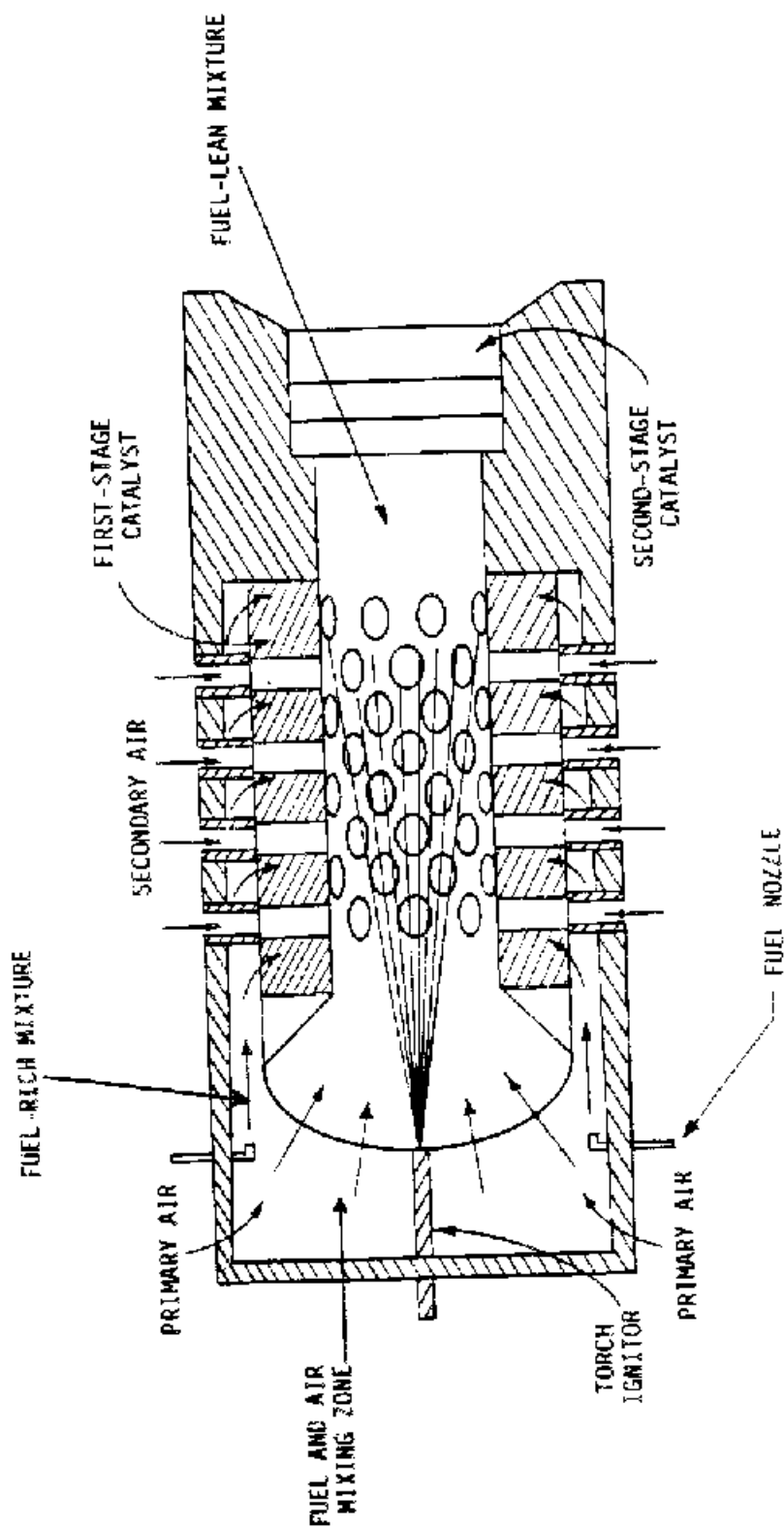


Figure 5-34. A rich/lean catalytic combustor.⁸⁹

Catalytic combustors can also be designed to operate in a rich/lean configuration, as shown in Figure 5-34. In this configuration, the air and fuel are premixed to form a fuel-rich mixture, which passes through a first stage catalyst where combustion begins. Secondary air is then added to produce a lean mixture, and combustion is completed in a second stage catalyst bed.⁸⁹

5.8.2 Applicability

Catalytic combustion techniques apply to all combustor types and are effective on both distillate oil- and natural gas-fired turbines. Because of the limited operating temperature range, catalytic combustors may not be easily applied to gas turbines subject to rapid load changes (such as utility peaking turbines).⁹⁰ Gas turbines that operate continuously at base load (such as industrial cogeneration applications) would not be as adversely affected by any limits on load following capability.⁹¹

5.8.3 Development Status

Presently, the development of catalytic combustors has been limited to bench-scale tests of prototype combustors. The major problem is the development of a catalyst that will have an acceptable life in the high-temperature and -pressure environment

of gas turbine combustors. Additional problems that must be solved are combustor ignition and how to design the catalyst to operate over the full gas turbine operating range (idle to full load).⁹²

5.9 OFFSHORE OIL PLATFORM APPLICATIONS

Gas turbines are used on offshore platforms to meet compression and electrical power requirements. This application presents unique challenges for NO_x emissions control due to the duty cycle, lack of a potable water source for wet injection, and limited space and weight considerations. The duty cycle for electric power applications of offshore platforms is unique. This duty cycle is subject to frequent load changes that can instantaneously increase or decrease by as much as a factor of 10.⁹³ Fluctuating loads result in substantial swings in turbine exhaust gas temperatures and flow rates. This presents a problem for SCR applications because the NO_x reduction efficiency depends upon temperature and space velocity (see Section 5.3.3).

The lack of a potable water supply means that water must be shipped to the platform or sea water must be desalinated and treated. The limited space and weight requirements associated with an SCR system may also have an impact on capital costs of the platform.

A 4-year study is underway for the Santa Barbara County Air Pollution Control Board to evaluate suitable NO_x control techniques for offshore applications. The goals of the study are to reduce turbine NO_x emissions at full load to 9 ppmv, corrected to 15 percent O₂, firing platform gas fuel and to achieve part load reductions of 50 percent. The study consists of two phases. The first phase, an engineering evaluation of available and emerging emission control technologies, is completed. The second phase will select the final control technologies and develop these technologies for offshore platform applications. Phase I

of this study concludes that the technologies with the highest estimated probability for success in offshore applications are:

- Water injection plus SCR (80 percent);
- Methanol fuel plus SCR (70 percent);
- Lean premixed combustion plus SCR (65 percent); and
- Steam dilution of fuel prior to combustion plus SCR (65 percent).

A key conclusion drawn from Phase I of this study is that none of the above technologies or combination of technologies in offshore platform applications currently has a high probability of successfully achieving the NO_x emission reduction goals of this study without substantial cost and impacts to platform and turbine operations, added safety considerations, and other environmental concerns. These issues will be further studied in Phase II for the above control technologies.

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6.0 CONTROL COSTS

Capital and annual costs are presented in this chapter for the nitrogen oxide (NO_x) control techniques described in Chapter 5.0. These control techniques are water and steam injection, low- NO_x combustion, and selective catalytic reduction (SCR) used in combination with these controls. Model plants were developed to evaluate the control techniques for a range of gas turbine sizes, fuel types, and annual operating hours. The gas turbines chosen for these model plants range in size from 1.1 to 160 megawatts (MW) (1,500 to 215,000 horsepower [hp]) and include both aeroderivative and heavy-duty turbines. Model plants were developed for both natural gas and distillate oil fuels. For offshore oil production platforms, cost information was available only for one turbine model.

The life of the control equipment depends upon many factors, including application, operating environment, maintenance practices, and materials of construction. For this study, a 15-year life was chosen.

Both new and retrofit costs are presented in this chapter. For water and steam injection, these costs were assumed to be the same because most of the water treatment system installation can be completed while the plant is operating and because gas turbine nozzle replacement and piping connections to the treated water supply can be performed during a scheduled downtime for maintenance. Estimated costs are provided for both new and retrofit low- NO_x combustion applications. No SCR retrofit applications were identified, and costs for SCR retrofit applications were not available. The cost to retrofit an

existing gas turbine installation with SCR would be considerably higher than the costs shown for a new installation, especially for combined cycle and cogeneration installations where the heat-recovery steam generator (HRSG) would have to be modified or replaced to accommodate the catalyst reactor.

This chapter is organized into five sections. Water and steam injection costs are described in Section 6.1. Low-NO_x combustor costs are summarized in Section 6.2. Costs for SCR used in combination with water or steam injection or low-NO_x combustion are described in Section 6.3. Water injection and SCR costs for offshore gas turbines are presented in Section 6.4, and references are listed in Section 6.5.

a. WATER AND STEAM INJECTION AND OIL-IN-WATER EMULSION

Ten gas turbines models were selected, and from these turbines 24 model plants were developed using water or steam injection or water-in-oil emulsion to control NO_x emissions. These 24 models, shown in Table 6-1

TABLE 6-1. GAS TURBINE MODEL PLANTS FOR NO_x CONTROL TECHNIQUES

Model plant ^a	GT model	Turbine output, MW	Annual operating hours	Fuel, natural gas or oil	Type of emission control	Aeroderivative (AD) or heavy-duty (HD) turbine
CON-G-W-3.3	Centaur T4500	3.3	8,000	Gas	Water	HD
CON-G-W-4.0	501-KB5	4.0	8,000	Gas	Water	AD
CON-G-W-22.7	LM2500	22.7	8,000	Gas	Water	AD
CON-G-W-26.8	MS5001P	26.8	8,000	Gas	Water	HD
CON-G-W-83.3	ABB GT11N	83.3	8,000	Gas	Water	HD
CON-G-W-84.7	MS7001E	84.7	8,000	Gas	Water	HD
CON-G-S-4.0	501-KB5	4.0	8,000	Gas	Steam	AD
CON-G-S-22.7	LM2500	22.7	8,000	Gas	Steam	AD
CON-G-S-26.8	MS5001P	26.8	8,000	Gas	Steam	HD
CON-G-S-34.4	LM5000	34.5	8,000	Gas	Steam	AD
CON-G-S-83.3	ABB GT11N	83.3	8,000	Gas	Steam	HD
CON-G-S-84.7	MS7001E	84.7	8,000	Gas	Steam	HD
CON-G-S-161	MS7001F	161	8,000	Gas	Steam	HD
CON-O-W-3.3	Centaur T4500	3.3	8,000	Oil	Water	HD
CON-O-W-26.3	MS5001P	26.3	8,000	Oil	Water	HD
CON-O-W-83.3	MS7001E	83.3	8,000	Oil	Water	HD
PKR-G-W-3.3	Centaur T4500	3.3	2,000	Gas	Water	HD
PKR-G-W-26.8	MS5001P	26.8	2,000	Gas	Water	HD
PKR-G-W-84.7	MS7001E	84.7	2,000	Gas	Water	HD
PKR-O-W-3.3	Centaur T4500	3.3	2,000	Oil	Water	HD
PKR-O-W-26.3	MS5001P	26.3	2,000	Oil	Water	HD
PKR-O-W-84.7	MS7001E	84.7	2,000	Oil	Water	HD
STD-O-W-1.1	Saturn T1500	1.0	1,000	Oil	Water	HD
STD-O-E-28.0	TPM FT4	28.0	1,000	Oil	Water-in-oil emulsion	AD

^aModel plant legend: First entry: annual operating hours
CON--continuous duty, 8,000 hours
PKR--peaking duty, 2,000 hours
STD--stand-by duty, 1,000 hours

Second entry: fuel type
G = natural gas fuel
O = oil fuel

Third entry: control type
W = water injection
S = steam injection
E = water-in-oil emulsion

Fourth entry: power output in MW

For example, CON-G-W-3.3 designates that the model plant is continuous-duty, uses natural gas fuel, has water injection, and has a power output of 3.3 MW.

, characterize variations in existing units with respect to turbine size, type (i.e., aero-derivative vs. heavy duty), operating hours, and type of fuel. A total of 24 model plants were developed; 16 of these were continuous-duty (8,000 hours per year) and 8 were intermittent-duty (2,000 or 1,000 hours per year). Thirteen of the continuous-duty model plants burn natural gas fuel; 6 of the 13 use water injection, and 7 use steam injection to reduce NO_x emissions. The three remaining continuous-duty model plants burn distillate oil fuel and use water injection to reduce NO_x emissions. Of the eight intermittent-duty model plants, six operate 2,000 hours per year (three natural gas-fueled and three distillate oil-fueled), and two operate 1,000 hours per year (both distillate oil-fueled). All intermittent-duty model plants use water rather than steam for NO_x reduction because it was assumed that the additional capital costs associated with steam-generating equipment could not be justified for intermittent service.

Costs were available for applying water-in-oil emulsion technology to only one gas turbine, and insufficient data were available to develop costs for a similar water-injected model

plant for this turbine. As a result, the costs and cost effectiveness for the water-in-oil emulsion model plant should not be compared to those of water-injected model plants.

Capital costs are described in Section 6.1.1, annual costs are described in Section 6.1.2, and emission reductions and the cost effectiveness of wet injection controls are discussed in Section 6.1.3. Additional discussion of the cost methodology and details about some of the cost estimating procedures are provided in Appendix B.

Fuel rates and water flow rates were calculated for each model plant using published design power output and efficiency, expressed as heat rate, in British thermal units per kilowatt-hour (Btu/kWh).¹ The values for these parameters are presented in Table 6-2

TABLE 6-2. FUEL AND WATER FLOW RATES FOR WATER AND STEAM INJECTION (1990 \$)

Model plant	GT model	Turbine output, kW	Heat rate (HR), Btu/kW-hr	Fuel flow		Estimated WFR, lb water/lb fuel	Water flow, gal/min ^c	Treatment system capacity, gal/min ^d
				lb/hr ^a	MMBtu/yr ^b			
CON-G-W-3.3	Centaur T4500	3,270	12,900	2,050	337,000	0.61	2.50	4.20
CON-G-W-4.0	501-KB5	4,000	12,700	2,460	406,000	0.80	3.94	6.60
CON-G-W-22.7	LM2500	22,670	9,220	10,100	1,670,000	0.73	14.8	24.7
CON-G-W-26.8	MS5001P	26,800	11,870	15,400	2,540,000	0.72	22.2	37.2
CON-G-W-83.3	ABB GT11N	83,300	10,400	42,000	6,930,000	1.83	154	258
CON-G-W-84.7	MS7001E	84,700	10,400	42,700	7,050,000	0.81	69.2	116
CON-G-S-4.0	501-KB5	4,000	12,700	2,460	406,000	1.50	7.38	12.4
CON-G-S-22.7	LM2500	22,670	9,220	10,100	1,670,000	1.46	29.5	49.5
CON-G-S-26.8	MS5001P	26,800	11,870	15,400	2,540,000	1.08	33.3	55.8
CON-G-S-34.4	LM5000	34,450	9,080	15,200	2,500,000	1.67	50.8	85.2
CON-G-S-83.3	ABB GT11N	83,300	10,400	42,000	6,930,000	2.12	178	299
CON-G-S-84.7	MS7001E	84,700	10,400	42,700	7,050,000	1.22	104	175
CON-G-S-161	MS7001F	161,000	9,500	74,200	12,240,000	1.34	199	334
CON-O-W-3.3	Centaur T4500	3,270	12,900	2,300	337,000	0.60	2.76	4.63
CON-O-W-26.3	MS5001P	26,300	11,950	17,100	2,510,000	0.79	27.0	45.3
CON-O-W-83.3	MS7001E	83,300	10,470	47,600	6,980,000	0.67	63.8	107
PKR-G-W-3.3	Centaur T4500	3,270	12,900	2,050	84,400	0.61	2.50	4.20
PKR-G-W-26.8	MS5001P	26,800	11,870	15,400	640,000	0.72	22.2	37.2
PKR-G-W-84.7	MS7001E	84,700	10,400	42,700	1,760,000	0.81	69.2	116
PKR-O-W-3.3	Centaur T4500	3,270	12,900	2,300	84,000	0.60	2.76	4.63
PKR-O-W-26.3	MS5001P	26,300	11,950	17,100	630,000	0.79	27.0	45.3
PKR-O-W-84.7	MS7001E	83,300	10,470	47,600	1,740,000	0.67	63.8	107
STD-O-W-1.1	Saturn T1500	1,130	14,200	875	16,000	0.46	0.81	1.35
STD-O-E-28.0	TPM ET4	28,000	14,500	19,700	406,000	0.55	21.7	36.4

^aNatural gas: lb/hr = HR x kW x (lb/20,610 Btu). Diesel oil: lb/hr = HR x kW x (lb/18,330 Btu).

^bMMBtu/yr = HR x kW x (MM/10⁶) x (operating hours/year).

^cWater (or steam) flow, gal/min = Fuel flow (lb/hr) x (1 hr/60 min) x (1 gal/8.33, lb. H₂O) x WFR.

A 30 percent design factor has been included per discussion with system supplier, and the waste stream from the water treatment system is calculated to be 29 percent. The design capacity is therefore Water Flow x 1.3 x 1.29.

for each model plant. Fuel rates were estimated based on the heat rates, the design output, and the lower heating value (LHV) of the fuel. The LHV's used in this analysis for natural gas and diesel fuel are 20,610 Btu per pound (Btu/lb) and 18,330 Btu/lb, respectively, as shown in Table 6-3

TABLE 6-3. FUEL PROPERTIES AND UTILITY AND LABOR RATES^a

Fuel properties	Factor	Units	Reference
Natural gas	20,610	Btu/lb	Ref. 3
	930	Btu/scf ^c (LHV)	Ref. 3
Diesel fuel	18,330	Btu/lb (LHV)	Ref. 2
	7.21	lb/gal	Ref. 2
Utility rates			
Natural gas ^b	3.88	\$/scf	Ref. 4
Diesel fuel	0.77	\$/gal	Ref. 5
Electricity	0.06	\$/kw-hr	Ref.'s 6 and 7
Raw water	0.384	\$/1,000 gal	Ref. 2, escalated @ 5% per year
Water treatment	1.97	\$/1,000 gal	Ref. 2, escalated @ 5% per year
Waste disposal	3.82	\$/1,000 gal	Ref. 2, escalated @ 5% per year
Labor rate			
Operating	25.60	\$/hr	Ref. 2, escalated @ 5% per year
Maintenance	31.20	\$/hr	Ref. 2, escalated @ 5% per year

^aAll costs are average costs in 1990 dollars.

^bNatural gas and electricity costs from Reference 4 are the average of the costs for industrial and commercial customers.

^cscf = standard cubic foot.

.² Water (or steam) injection rates were calculated based on published fuel rates and water-to-fuel ratios (WFR) provided by manufacturers.⁸⁻¹² According to a water treatment system supplier, treatment facilities are designed with a capacity factor of 1.3.¹³ An additional 29 percent of the treated water flow rate is discarded as wastewater.² Consequently, the water treatment facility design capacity is 68 percent (1.30×1.29) greater than the water (or steam) injection rate.

i. Capital Costs

The capital costs for each model plant are presented in Table 6-4

TABLE 6-4. CAPITAL COSTS FOR WET INJECTION IN THOUSAND OF DOLLARS ^a

Model plant	GT model	Injection system (IS) ^b	Water treatment system (WTS) ^c	Total system (TS) = (IS + WTS)	Taxes and freight (TF) = (8% of TS)	Direct install. costs (DC) = (45% [TS + TF])	Indirect install. costs (IC) = (33% of [TS + TF + DC] + 5,000)	Contingency (C) = (20% of [TS + TF + DC + IC])	Total capital cost (TCC) = [TS + TF + DC + IC + C]
CON-G-W-3.3	Centaur T4500	113	89.9	203	16.2	50.0 ^d	53.8 ^e	64.6	388
CON-G-W-4.0	501-KB5	115	113	228	18.2	50.0 ^d	59.2 ^e	71.0	426
CON-G-W-22.7	LM2500	212	218	430	34.4	209	227	180	1,080
CON-G-W-26.8	MS5001P	215	268	483	38.6	235	254	202	1,210
CON-G-W-83.3	ABB GT11N	874	705	1,580	126	768	822	659	3,950
CON-G-W-84.7	MS7001E	562	473	1,030	82.4	501	537	430	2,580
CON-G-S-4.0	501-KB5	154	154	308	24.7	50.0	76.6	92.0	552
CON-G-S-22.7	LM2500	278	309	587	46.9	285	308	245	1,470
CON-G-S-26.8	MS5001P	262	328	590	47.2	287	310	247	1,480
CON-G-S-34.4	LM5000	530	405	935	74.8	454	488	391	2,340
CON-G-S-83.3	ABB GT11N	1,090	759	1,850	148	899	961	772	4,630
CON-G-S-84.7	MS7001E	715	580	1,300	104	632	677	543	3,260
CON-G-S-161	MS7001F	1,130	802	1,930	154	938	1,000	804	4,830
CON-O-W-3.3	Centaur T4500	114	94.5	208	16.7	50.0 ^d	55.0 ^e	66.0	396
CON-O-W-26.3	MS5001P	231	296	527	42.1	256	277	220	1,320
CON-O-W-83.3	MS7001E	532	454	986	78.9	479	515	412	2,470
PKR-G-W-3.3	Centaur T4500	113	89.9	203	16.2	50.0 ^d	53.8 ^e	64.6	388
PKR-G-W-26.8	MS5001P	215	268	483	38.6	235	254	202	1,210
PKR-G-W-84.7	MS7001E	562	473	1,030	82.4	501	537	430	2,580
PKR-O-W-3.3	Centaur T4500	114	94.5	208	16.7	50.0 ^d	55.0 ^e	66.0	396
PKR-O-W-26.3	MS5001P	231	296	527	42.1	256	277	220	1,320
PKR-O-W-84.7	MS7001E	532	454	986	78.9	479	515	412	2,470
STD-O-W-1.1	Saturn T1500	71.9	51.0	123	9.83	50.0	36.6	43.9	263
STD-O-E-28.0	TPM ET4	128	NA ^f	128	10.2	62.2	71.1	54.3	326

^aAll costs in 1990 dollars.

^bInjection nozzle costs provided by manufacturers. Balance of water injection system calculated at a cost of \$4,200 x GPM.

^cWTS = 43,900 x (design capacity, gal/min) ^{0.5}

^dDirect installation cost is estimated at \$50,000 for model plants rated at 5 MW or less.

^eIndirect installation cost factor of 33 percent is reduced to 20 percent for model plants rated at 5 MW or less.

^fNA = cost calculations based on using a portable demineralizer systems during turbine operating periods. Cost for system usage is included in Table 6-5.

. These costs were developed based on methodology in Reference 2, which is presented in this section. The capital costs include purchased equipment costs, direct and indirect installation costs, and contingency costs.

(1) Purchased Equipment Costs. Purchased equipment costs consist of the injection system, the water treatment system, taxes, and freight. All costs are presented in 1990 dollars.

(a) Water injection system. The injection system delivers water from the treatment system to the combustor. This system includes the turbine-mounted injection nozzles, the flow metering controls, pumps, and hardware and interconnecting piping from the treatment system to the turbine. On-engine hardware (the injection nozzles) costs were provided by turbine manufacturers.^{9,14-17} Flow metering controls and hardware, pumps, and interconnecting piping costs for all turbines were calculated using data provided by General Electric for four heavy-duty turbine models.¹⁷ No relationship between costs and either turbine output or water flow was evident, so the sum of the four costs was divided by the sum of the water flow requirements for the four turbines. This process yielded a cost of \$4,200 per gallon per minute (gal/min), and this cost, added to the on-engine hardware costs, was used for all model plants.

(b) Water treatment system. The water treatment process, and hence the treatment system components, varies according to the degree to which the water at a given site must be treated. For this cost analysis, the water treatment system includes a reverse osmosis and mixed-bed demineralizer system. The water treatment system capital cost for each model plant was estimated based on an equation developed in Reference 2:

$$WTS = 43,900 \times (G)^{0.50}$$

where

WTS = water treatment system capital cost, \$; and

G = water treatment system design capacity, gal/min.

This equation yields costs that are generally consistent with the range of costs presented in Reference 18.

(c) Taxes and freight. This cost covers applicable sales taxes and shipment to the site for the injection and water treatment systems. A figure of 8 percent of the total system cost was used.^{2,7}

(2) Direct Installation Costs. This cost includes the labor and material costs associated with installing the foundation and supports, erecting and handling equipment, electrical work, piping, insulation, and painting. For smaller

turbines, the water treatment system is typically skid-mounted and is shipped to the site as a packaged unit, which minimizes field assembly and interconnections. The cost to install a skid-mounted water treatment skid is typically \$50,000, and this cost is used for the direct installation cost for model plants less than 5 MW (6700 hp).¹⁹ For larger turbines, it is expected that the water treatment system must be field-assembled and the direct installation costs were calculated as 45 percent of the injection and water treatment systems, including taxes and freight.²

(3) Indirect Installation Costs. This cost covers the indirect costs (engineering, supervisory personnel, office personnel, temporary offices, etc.) associated with installing the equipment. The cost was taken to be 33 percent of the systems' costs, taxes and freight, and direct costs, plus \$5,000 for model plants above 5 MW (6,700 hp).² The indirect installation costs for skid-mounted water treatment systems are expected to be less than for field-assembled systems; therefore, for model plants with an output of less than 5 MW (6,700 hp), the cost percentage factor was reduced from 33 to 20 percent.

(4) Contingency Cost. This cost is a catch-all meant to cover unforeseen costs such as equipment redesign/ modification, cost escalations, and delays encountered in startup. This cost was estimated as 20 percent of the sum of the systems, taxes and freight, and direct and indirect costs.²

ii. Annual Costs

The annual costs are summarized in Table 6-5

TABLE 6-5. ANNUAL COSTS FOR WATER AND STEAM INJECTION (1990 \$)

Model plant	GT model	Fuel penalty (FP) ^a	Electricity (E) ^b	Added maintenance cost (M) ^c	Water treatment (WT) ^d				Plant overhead (PO) = (30% of M)	G&A taxes, insurance (GATI) ⁱ	Capital recovery (CR) ^j	Total annual cost (TAC) ^k
					Raw water ^e	Treat-ment ^f	Labor ^g	Disposal ^h				
CON-G-W-3.3	Centaur T4500	30,000	193	16,000	595	3,050	1,080	1,330	4,800	15,500	51,000	124,000
CON-G-W-4.0	501-KB5	47,400	304	24,000	936	4,800	1,710	2,090	7,200	17,100	56,100	162,000
CON-G-W-22.7	LM2500	178,000	1,140	28,000	3,510	18,000	6,390	7,210	8,400	43,200	142,000	436,000
CON-G-W-26.8	MS5001P	267,000	1,714	33,000	5,270	27,100	9,620	11,800	9,900	48,400	159,000	573,000
CON-G-W-83.3	ABB GT11N	1,852,000	11,884	0	36,600	188,000	66,700	81,800	0	158,000	519,000	2,910,000
CON-G-W-84.7	MS7001E	834,000	5,348	25,700	16,500	84,400	30,000	36,800	7,710	103,000	339,000	1,480,000
CON-G-S-4.0	501-KB5	25,400	571	24,000	1,760	9,010	1,600	3,930	7,200	22,100	72,600	168,000
CON-G-S-22.7	LM2500	102,000	2,280	0	7,020	36,000	6,390	15,700	0	58,800	193,000	421,000
CON-G-S-26.8	MS5001P	114,000	2,572	33,000	7,910	40,600	7,210	17,700	9,900	59,200	195,000	487,000
CON-G-S-34.4	LM5000	174,000	3,925	0	12,100	62,000	11,000	27,000	0	93,600	308,000	692,000
CON-G-S-83.3	ABB GT11N	613,000	13,768	0	42,400	217,000	38,600	94,700	0	185,000	609,000	1,810,000
CON-G-S-84.7	MS7001E	359,000	8,055	0	24,800	127,000	22,600	55,400	0	130,000	429,000	1,160,000
CON-G-S-161	MS7001F	684,000	15,374	0	47,300	243,000	43,100	106,000	0	193,000	635,000	1,970,000
CON-O-W-3.3	Centaur T4500	41,200	213	20,800	657	3,370	1,200	1,470	6,240	15,800	52,100	143,000
CON-O-W-26.3	MS5001P	404,000	2,089	42,900	6,430	33,000	11,700	14,400	12,900	52,800	174,000	754,000
CON-O-W-83.3	MS7001E	954,000	4,931	33,400	15,200	77,800	27,700	33,900	10,020	98,800	325,000	1,580,000
PKR-G-W-3.3	Centaur T4500	7,500	48.3	4,000	149	760	270	330	1,200	15,500	51,000	80,800
PKR-G-W-26.8	MS5001P	67,000	429	8,250	1,320	6,770	2,400	2,950	2,500	48,400	159,000	299,000
PKR-G-W-84.7	MS7001E	208,000	1,337	6,430	4,110	21,100	7,500	9,200	1,929	103,000	339,000	702,000
PKR-O-W-3.3	Centaur T4500	10,300	53.3	5,200	164	840	300	370	1,560	15,800	52,100	86,700
PKR-O-W-26.3	MS5001P	101,000	522	10,725	1,610	8,240	2,930	3,590	3,200	52,800	174,000	359,000
PKR-O-W-84.7	MS7001E	238,000	1,233	8,350	3,790	19,500	6,910	8,480	2,505	99,000	325,000	713,000
STD-O-W-1.1	Saturn T1500	1,500	7.78	1,300	23.9	123	43.7	53.6	390	10,530	34,600	48,600
STD-O-E-28.0	TPM FT4	45,500	209	0	644	51,100	1,170	1,440	0	13,000	42,900	156,000

^aFP for water = 0.035 x WFR x (MMBtu/yr) x (ft³/940 Btu) x (\$3.88/1,000 ft³) x (10⁶/MM).

^bE = Water flow rate (gal/min) x 0.161 x operating hours x (\$0.06/kWh).

^cMaintenance costs for the Centaur and Allison 501 turbines were obtained from the manufacturers. Costs for the MS5001 and MS7001 were estimated based on information about inspections and parts replacement presented in Appendix B. Maintenance for turbines that use diesel fuel are 30 percent higher than costs for comparable turbines using natural gas. No additional maintenance costs were assessed for steam injection.

^dWT = water treatment cost (gal/min) x (\$0.384/1,000 gal) x (60 min/hour) x operating hours x 1.29.

^eRaw water cost = Water Flow (gal/min) x (\$1.97/1,000 gal) x (60 min/hour) x operating hours x 1.29.

^fTreat-ment cost = Water Flow (gal/min) x (\$0.70/1,000 gal) x (60 min/hour) x operating hours x 1.29.

^gLabor Cost for water = Water Flow (gal/min) x (\$0.70/1,000 gal) x (60 min/hour) x operating hours x 1.29 x 0.5.

^hDisposal Cost = Water Flow (gal/min) x (\$3.82/1,000 gal) x (60 min/hour) x operating hours x 0.29.

ⁱGATI = 0.04 x TCC (TCC is shown in Table 6-4).

^jCR = 0.1315 x TCC based on an equipment life of 15 years and a 10 percent interest rate.

for each model plant. Annual costs include the fuel penalty; electricity; maintenance requirements; water treatment; overhead, general and administrative, taxes, and insurance; and capital recovery, as discussed in this section.

(1) Fuel Penalty. The reduction in efficiency associated with water injection varies for each turbine model. Based on data in Reference 2, it was estimated that a WFR of 1.0 corresponds to a fuel penalty of 3.5 percent for water injection and 1.0 percent for steam injection. This percentage was multiplied by the actual WFR and the annual fuel cost to

determine the fuel penalty for each model plant. The fuel flow was multiplied by the unit fuel costs to determine the annual fuel costs. As shown in Table 6-3, the natural gas cost is \$3.88/1,000 standard cubic feet (scf) and the diesel fuel cost is \$0.77/gal.^{4,5}

An increase in output from the turbine accompanies the decrease in efficiency. This increase was not considered, however, because not all sites have a demand for the available excess power. In applications such as electric power generation, where the excess power can be used at the site or added to utility power sales, this additional output would serve to decrease or offset the fuel penalty impact.

(2) Electricity Cost. The electricity costs shown in Table 6-5 apply to the feedwater pump(s) for water or steam injection. The pump power requirements are estimated from the pump head (ft) and the water flow rate as shown in the following equation:²

$$\text{power pump (kW}_e\text{)} = \frac{\text{FR}}{3,960} \times H \times (\text{S.G.}) \times \frac{1}{0.6} \times \frac{0.7457 \text{ kW}}{\text{hp}} \times \frac{1}{0.9}$$

where:

- FR = feedwater flow rate, gal/min (from Table 6-2);
- H = total pump head (ft);
- S.G. = specific gravity of the feed water;
- 0.6 = pump efficiency of 60 percent;
- 0.9 = electric motor efficiency of 90 percent;
- 3,960 = factor to correct units in FR and H to hp; and
- 0.7457 = factor to convert hp to kW.

For water injection, the feedwater pump(s) supply treated water to the gas turbine injection system. For steam injection, the feedwater pump(s) supply treated water to the boiler for steam generation. This cost analysis uses a feedwater temperature of 55°C (130°F) with a density of 61.6 lb/ft³ and a total pump head requirement of 200 pounds per square inch, gauge (psig)

(468 ft).² Based on these values, the pump electrical demand for either water or steam injection is calculated as follows:

$$\begin{aligned}\text{pump power (kW}_e\text{)} &= \frac{\text{FR} \times 468}{3,960} \times \frac{61.6}{62.4} \times \frac{1}{0.6} \times 0.7457 \times \frac{1}{0.9} \\ &= 0.161 \times \text{FR}\end{aligned}$$

The electrical cost for each model plant is the product of the pump electrical demand, the annual hours of operation, and the unit cost of electricity. The unit cost of electricity, shown in Table 6-3, is \$0.06/kWh.^{6,7}

Maintenance costs were developed based on information from manufacturers, and water treatment labor costs were estimated based on information from a water treatment vendor. Other costs were developed based on the methodology presented in Reference 2.

No backup steam or electricity costs were developed for water or steam injection because it was assumed that no additional downtime would be required for scheduled inspections and repairs. Maintenance intervals could be scheduled to coincide with the 760 hr/yr of downtime that are currently allocated for scheduled maintenance. If this were done, the annual utilization of the backup source would not increase.

(3) Added Maintenance Costs. Based on discussions with gas turbine manufacturers, additional maintenance is required for some gas turbines with water injection. The analysis procedures used to develop the incremental maintenance costs are presented in Appendix B.

The incremental maintenance cost associated with water injection for natural gas-fueled turbines was provided by the gas turbine manufacturers.^{10, 20-24} All gas turbine manufacturers contacted stated that there were no incremental maintenance costs for operation with steam injection. Two manufacturers provided maintenance costs for natural gas and oil fuel operation without water injection.^{10, 20} Using an average of these costs, incremental maintenance costs for water injection are 30 percent higher for

plants that use diesel fuel instead of natural gas. Costs were prorated for model plants that operate less than 8,000 hr/yr.

(4) Water Treatment Costs. Water treatment operating costs include the cost of treatment (e.g., for chemicals and media filters), operating labor, raw water, and wastewater disposal. The raw water flow rate is equal to the treated water flow rate (the water or steam injection rate) plus the flow rate of the wastewater generated in the treatment plant. As noted in Section 6.1, the wastewater flow rate is equal to 29 percent of the injection flow rate. The annual raw water, treated water, and wastewater flow rates were multiplied by the appropriate unit costs in Table 6-3 to determine the annual costs. Water treatment labor costs were calculated at \$0.70/1,000 gal for water injection.²⁵ This cost was multiplied by the total annual treated water flow rate to determine the annual water treatment labor cost for water injection. Labor costs for steam injection were assumed to be half as much as the costs for water injection because it was assumed that the facility already has a water treatment plant for the boiler feedwater. Therefore, the operator requirements would be only those associated with the increase in capacity of the existing treatment plant.

(5) Plant Overhead. This cost is the overhead associated with the additional maintenance effort required for water injection. The cost was calculated as 30 percent of the added maintenance cost from Section 6.1.2.3.²

(6) General and Administrative, Taxes, and Insurance Costs (GATI). This cost covers those expenses for administrative overhead, property taxes, and insurance and was calculated as 4 percent of the total capital cost.²

(7) Capital Recovery. A capital recovery factor (CRF) was multiplied by the total capital investment to estimate uniform end-of-year payments necessary to repay the investment. The CRF used in this analysis is 0.1315, which is based on an equipment life of 15 years and an interest rate of 10 percent.

(8) Total Annual Cost. This cost is the sum of the annual costs presented in Sections 6.1.2.1 through 6.1.2.7 and is the

total cost that must be paid each year to install and operate water or steam injection NO_x emissions control for a gas turbine.

iii. Emission Reduction and Cost-Effectiveness Summary for Water and Steam Injection

TABLE 6-6. COST-EFFECTIVENESS SUMMARY FOR WATER AND STEAM INJECTION (1990 \$)

Model plant	GT model	NO _x emissions ^a					Total NO _x removed, tons/yr	Total annual cost, \$	Cost effectiveness, \$/ton
		Uncontrolled NO _x		Controlled NO _x					
		ppmv ^b	tons/yr	ppmv	Controlled NO _x				
					b tons/yr				
CON-G-W-3.3	Centaur T4500	130	88.1	42	28.5	59.6	124,000	2,080	
CON-G-W-4.0	501-KB5	155	126	42	34.2	91.9	162,000	1,760	
CON-G-W-22.7	LM2500	174	581	42	140	441	436,000	989	
CON-G-W-26.8	MS5001P	142	723	42	214	509	573,000	1,130	
CON-G-W-83.3	ABB GT11N	390	5,410	25	347	5,060	2,910,000	575	
CON-G-W-84.7	MS7001E	154	2,170	42	593	1,580	1,480,000	937	
CON-G-S-4.0	501-KB5	155	126	42	34.2	91.9	168,000	1,830	
CON-G-S-22.7	LM2500	174	581	25	83.5	497	421,000	846	
CON-G-S-26.8	MS5001P	142	723	42	214	509	487,000	957	
CON-G-S-34.4	LM5000	185	930	25	126	804	692,000	861	
CON-G-S-83.3	ABB GT11N	390	5,410	42	583	4,830	1,810,000	375	
CON-G-S-84.7	MS7001E	154	2,170	42	593	1,580	1,160,000	734	
CON-G-S-161	MS7001F	210	5,150	42	1,030	4,120	1,970,000	478	
CON-O-W-3.3	Centaur T4500	179	125	60	41.8	82.9	143,000	1,720	
CON-O-W-26.3	MS5001P	211	1,090	65	337	753	754,000	1,000	
CON-O-W-83.3	MS7001E	228	3,290	65	938	2,350	1,580,000	672	
PKR-G-W-3.3	Centaur T4500	130	22.0	42	7.12	14.9	80,800	5,420	
PKR-G-W-26.8	MS5001P	142	181	42	53.5	127	299,000	2,350	
PKR-G-W-84.7	MS7001E	154	543	42	148	395	702,000	1,780	
PKR-O-W-3.3	Centaur T4500	179	31.2	60	10.5	20.7	86,700	4,180	
PKR-O-W-26.3	MS5001P	211	273	65	84.2	189	359,000	1,900	
PKR-O-W-84.7	MS7001E	228	822	65	234	588	713,000	1,210	
STD-O-W-1.1	Saturn T1500	150	4.97	60	1.99	2.98	48,600	16,300	
STD-O-E-28.0	TPM FT4	150	122	50	37.3	84.7	156,000	1,840	

^aExample NO_x emission calculations are given in Appendix A.

^bReferenced to 15 percent oxygen.

^cFrom Table 6-5.

The uncontrolled and controlled NO_x emissions and the annual emission reductions for the model plants are shown in Table 6-6. The emissions, in tons per year (tons/yr), were calculated as shown in Appendix A.

The total annual cost was divided by the annual emission reductions to determine the cost effectiveness for each model plant. For continuous-duty natural gas-fired model plants, the cost-effectiveness figures range from approximately \$600 to \$2,100 per ton of NO_x removed for water injection, and decrease to approximately \$400 to \$1,850 per ton for steam injection. The lower range of cost-effectiveness figures for steam injection is primarily due to the greater NO_x reduction achieved with steam injection. For continuous-duty oil-fired model plants, the cost effectiveness ranges from approximately \$675 to \$1,750 per ton of NO_x removed, which is comparable to figures for gas-fired model plants. The cost-effectiveness figures are higher for gas turbines with lower power outputs because the fixed capital costs associated with wet injection system installation have the greatest impact on the smaller gas turbines.

Cost-effectiveness figures increase as annual operating hours decrease. For turbines operating 2,000 hr/yr, the cost-effectiveness figures are two to nearly three times higher than those for continuous-duty model plants, and increase further for model plants operating 1,000 hr/yr. For the oil-in-water emulsion model plant, the cost effectiveness corresponding to 1,000 annual operating hours is \$1,840/ton of NO_x removed. No data were available to prepare a conventional water injection model plant for this turbine to compare the relative cost-effectiveness values.

b. LOW-NO_x COMBUSTORS

Incremental capital costs for low-NO_x combustors relative to standard designs for new applications were provided by three manufacturers for several turbines.^{3, 14, 26} Based on information from the manufacturers, the performance and maintenance requirements for a low-NO_x combustor are expected to be the same as for a standard combustor, and so the only annual cost associated with low-NO_x combustors is the capital recovery. The capital recovery factor is 0.1315, assuming a life of 15 years and an interest rate of 10 percent.

Table 6-7

TABLE 6-7. COST-EFFECTIVENESS SUMMARY FOR DRY LOW-NO_x COMBUSTORS USING NATURAL GAS FUEL (1990 \$)

Model plant ^a	GT model	Power output, MW	Annual operating hours	NO _x emissions ^b				NO _x removed, tons/yr	Incremental capital cost,\$ ^d	Annual cost, \$ ^e	Cost effective- ness, \$/ton NO _x removed
				Uncontrolled NO _x		Controlled NO _x					
				ppmv ^c	Tons/yr	ppmv	Tons/yr				
CON-L-3.3-42	Centaur T4500	3.3	8,000	130	88.1	42.0	28.5	59.6	375,000	49,300	827
CON-L-4.0-42	Centaur H ¹	4.0	8,000	105	83.0	42.0	33.2	49.8	400,000	52,600	1,060
CON-L-4.5-42	Taurus	4.5	8,000	114	98.7	42.0	36.4	62.4	425,000	55,900	896
CON-L-8.8-42	Mars T12000	8.8	8,000	178	278	42.0	65.5	212	700,000	92,100	434
CON-L-10-42	Mars T14000	10.0	8,000	199	341	42.0	72.1	269	725,000	95,300	354
CON-L-3.3-25	Centaur T4500	3.3	8,000	130	88.1	25.0 ^f	16.9	71.2	375,000	49,300	693
CON-L-4.0-25	Centaur H ¹	4.0	8,000	105	83.0	25.0 ^f	19.8	63.2	400,000	52,600	832
CON-L-4.5-25	Taurus	4.5	8,000	114	98.7	25.0 ^f	21.7	77.1	425,000	55,900	725
CON-L-8.8-25	Mars T12000	8.8	8,000	178	278	25.0 ^f	39.0	239	700,000	92,100	386
CON-L-10-25	Mars T14000	10.0	8,000	199	341	25.0 ^f	42.9	299	725,000	95,300	319
CON-L-39-25	MS6000	39.0	8,000	220	1,480	25.0	168	1,310	1,400,000	184,000	140
CON-L-83-25	ABB GT11N	83.3	8,000	390	5,420	25.0	347	5,070	2,200,000	289,000	57.0
CON-L-85-25	MS7001E	84.7	8,000	154	2,180	25.0	353	1,830	2,140,000	281,000	154
CON-L-39-9	MS6000	39.0	8,000	220	1,480	9.00	60.6	1,420	1,400,000	184,000	130
CON-L-83-9	ABB GT11N	83.3	8,000	390	5,420	9.00	125	5,290	2,200,000	289,000	54.6
CON-L-85-9	MS7001E	84.7	8,000	154	2,180	9.00	127	2,050	2,140,000	281,000	137
PKR-L-3.3-42	Centaur T4500	3.3	2,000	130	22.0	42.0	7.12	14.9	375,000	49,300	3,310
PKR-L-4.0-42	Centaur H ¹	4.0	2,000	105	20.7	42.0	8.30	12.4	400,000	52,600	4,230
PKR-L-4.5-42	Taurus	4.5	2,000	114	24.7	42.0	9.09	15.6	425,000	55,900	3,590
PKR-L-8.8-42	Mars T12000	8.8	2,000	178	69.4	42.0	16.4	53.1	700,000	92,100	1,740
PKR-L-10-42	Mars T14000	10.0	2,000	199	85.4	42.0	18.0	67.3	725,000	95,300	1,420
PKR-L-3.3-25	Centaur T4500	3.3	2,000	130	22.0	25.0 ^f	4.24	17.8	375,000	49,300	2,770
PKR-L-4.0-25	Centaur H ¹	4.0	2,000	105	20.7	25.0 ^f	4.94	15.8	400,000	52,600	3,330
PKR-L-4.5-25	Taurus	4.5	2,000	114	24.7	25.0 ^f	5.41	19.3	425,000	55,900	2,900
PKR-L-8.8-25	Mars T12000	8.8	2,000	178	69.4	25.0 ^f	9.75	59.7	700,000	92,100	1,540
PKR-L-10-25	Mars T14000	10.0	2,000	199	85.4	25.0 ^f	10.7	74.6	725,000	95,300	1,280
PKR-L-39-25	MS6000	39.0	2,000	220	371	25.0	42.1	328	1,400,000	184,000	560
PKR-L-83-25	ABB GT11N	83.3	2,000	390	1,350	25.0	86.8	1,260	2,200,000	289,000	229
PKR-L-85-25	MS7001E	84.7	2,000	154	540	25.0	88.3	452	2,140,000	281,000	622
*PKR-L-39-9	MS6000	39.0	2,000	220	371	9.00	15.2	355	1,400,000	184,000	518
PKR-L-83-9	ABB GT11N	83.3	2,000	390	1,350	9.00	31.3	1,320	2,200,000	289,000	219
PKR-L-85-9	MS7001E	84.7	2,000	154	540	9.00	31.8	508	2,140,000	281,000	553

*Model plant legend: First entry: annual operating hours Second entry: control technique Third entry: power output, in MW Fourth entry: controlled NO_x level, ppmv at 15 percent O₂
CON - Continuous duty, 8,000 hours L - dry low-NO combustor
PKR - peaking/intermittent duty, 2,000 hours

For example, CON-L-3.3-42 designates that the model plant operates 8,000 hours per year, is fitted with a dry low-NO_x combustor, has a power output of 3.3 MW, and has a controlled NO_x level of 42 ppmv.

^bExample NO_x emission calculations are shown in Appendix A.

^cReferenced to 15 percent oxygen.

^dIncremental capital costs were provided by the manufacturers.

presents the uncontrolled and controlled emission levels, the annual emission reductions, incremental costs for a low-NO_x combustor over a conventional design, and the cost effectiveness of low-NO_x combustors for all gas turbine models for which sufficient data were available. Cost-effectiveness figures were calculated for 8,000 and 2,000 hours of operation annually, using controlled NO_x emission levels of 42, 25, and 9 parts per million, by volume (ppmv), referenced to 15 percent oxygen, which are the achievable levels stated by the turbine manufacturers. The cost effectiveness varies according to the uncontrolled NO_x emission level for the conventional combustor design and the achievable controlled emission level for the low-NO_x design. For continuous-duty applications, cost effectiveness for a controlled NO_x emission level of 42 ppmv ranges from \$353 to \$1,060 per ton of NO_x removed. The cost-effectiveness range decreases to \$57 to \$832 per ton of NO_x removed for a controlled NO_x emission level of 25 ppmv and decreases further to \$55 to \$137 per ton of NO_x removed for a 9 ppmv control level. In all cases, the cost effectiveness increases as the operating hours decrease. In general, the cost effectiveness is higher for smaller gas turbines than for larger turbines due to the relatively higher capital cost per kW for low-NO_x combustors for smaller turbines.

The cost-effectiveness range is lower for low-NO_x combustors than for water or steam injection because the total annual costs are lower and, in some cases, the controlled emission levels are

also lower. According to two turbine manufacturers, retrofit costs are 40 to 60 percent greater than the incremental costs shown in Table 6-7 for new installations.^{3,14}

c. SELECTIVE CATALYTIC REDUCTION

The costs for SCR for new installations were estimated for all model plants. Retrofit costs for SCR were not available but could be considerably higher than the costs shown for new installations, especially in applications where an existing heat recovery steam generator (HRSG) would have to be moved, modified, or replaced to accommodate the addition of a catalyst reactor.

To date, most gas turbine SCR applications use a base metal catalyst with an operating temperature range that requires cooling of the exhaust gas from the turbine. For this reason, SCR applications to date have been limited to combined cycle or cogeneration applications that include an HRSG, which serves to cool the exhaust gas to temperatures compatible with the catalyst. The introduction of high-temperature zeolite catalysts, however, makes it possible to install the catalyst directly downstream of the turbine, and therefore feasible to use SCR with simple-cycle applications as well as heat recovery applications. As discussed in Section 5.3.2, to date there is at least one gas turbine installation with a high-temperature zeolite catalyst installed downstream of the turbine and upstream of an HRSG. At present, no identified SCR systems are installed in simple-cycle gas turbine applications.

An overview of the procedures used to estimate capital and annual costs are described in Sections 6.3.1 and 6.3.2, respectively; a detailed cost algorithm is presented in Appendix B. The emission reduction and cost-effectiveness calculations are described in Section 6.3.3.

i. Capital Costs

Five documents in the technical literature contained SCR capital costs for 21 gas turbine facilities. Most of these documents presented costs that were obtained from vendors, but some may have also developed at least some costs based on their own experiences.²⁷⁻³¹ Most of the documents presented only the

total capital costs, not costs for individual components, and they did not provide complete descriptions of what the costs included. These costs were plotted on a graph of total capital costs versus gas turbine size. To this graph were added estimates of total installed costs for a high-temperature catalyst SCR system for installation upstream of the HRSG for four turbine installations ranging in size from 4.5 to 83 MW (6,030 to 111,000 hp). These high-temperature SCR system estimates include the catalyst reactor, air injection system for exhaust temperature control, ammonia storage and injection system, instrumentation, and continuous emission monitoring equipment. These SCR costs were estimated by the California Air Resources Board (CARB) in 1991 dollars and are based on NO_x emission levels of 42 ppmv into and 9 ppmv out of the SCR.³⁵ These estimated costs, shown in Appendix B, fit well within the range of costs from the 21 installations discussed above, and the equation of a line determined by linear regression adequately fits the data ($R^2 = 0.76$) for all 25 points. Based on this graph, the total capital cost for either a base-metal SCR system installed within the HRSG or a high-temperature zeolite catalyst SCR system installed directly downstream of the turbine can be calculated using the equation determined by the linear

TABLE 6-8. PROCEDURES FOR ESTIMATING CAPITAL AND ANNUAL COSTS FOR SCR CONTROL OF NO_x EMISSIONS FROM GAS TURBINES^a

A. Total capital investment, \$ ^b	= (49,700 x TMW) + 459,000
B. Direct annual costs, \$/yr	
1. Operating labor ^c	= (1.0 hr/8 hr-shift) x (\$25.60/hr) x (H)
2. Supervisory labor	= (0.15) x (operating labor)
3. Maintenance labor and materials	= (1,250 x TMW) + 25,800
4. Catalyst replacement	= (4,700 x TMW) + 37,200
5. Catalyst disposal ^d	= (V) x (\$15/ft ³) x (.2638)
6. Anhydrous ammonia ^e	= (N) x (\$360/ton)
7. Dilution steam ^f	= (N) x (0.95/0.05) x (MW H ₂ O/MW NH ₃) x (\$6/1,000 lb steam) x (2,000 lb/ton)
8. Electricity ^g	= N/A
9. Performance loss ^h	= (0.005) x (TMW) x (\$0.06/KWH) x (1,000 KW/MW) x (H)
10. Blower (if needed)	= 0.1 x (Performance Loss)
11. Production loss ⁱ	= None
C. Indirect annual costs, \$/yr	
1. Overhead	= (0.6) x (all labor and maintenance material costs)
2. Property taxes, insurance, and administration	= (0.04) x (total capital investment)
3. Capital recovery ^j	= (0.13147) x [total capital investment - (catalyst replacement/0.2638)]

^aAll costs are in average 1990 dollars.

^bTMW=turbine output in MW for each model plant.

^cThe annual operating hours are represented by the variable H. The labor rate of \$25.60/hr is from Table 6-3.

^dThe catalyst volume in ft³ is represented by the variable V. The catalyst volume for each model plant is estimated as V = (TMW) x (6,180 ft³/83 MW).

^eThe ammonia requirement in tons is represented by the variable N and is calculated using a NH₃-to-NO_x molar ratio of 1.0.

The annual tonnage of NO_x is taken from the controlled levels shown in Tables 6-11 and 6-12.

^fThe ammonia is diluted with steam to 5 percent by volume before injection.

^gThe amount of electricity required for ammonia pumps and exhaust fans is not known, but is expected to be small. The electricity cost comprised less than 1 percent of the total annual cost estimated by the South Coast Air Quality Management District (SCAQMD) for SCR applied to a 1.1 MW turbine.

^hBased on information from three sources, the backpressure from the SCR reduces turbine output by an average of about 0.9 percent.

ⁱNo production losses are estimated because it is assumed that all SCR maintenance, inspections, cleaning, etc. can be performed during the 760 hours of scheduled downtime per year.

^jThe capital recovery factor for the SCR is 0.13147, based on a 15-year equipment life and 10 percent interest rate. The catalyst is replaced every 5 years. The 0.2638 figure is the capital recovery factor for a 5-year equipment life and a 10 percent interest rate.

regression. This equation is shown in Table 6-8 and was used to calculate the total capital investment for SCR for each model plant shown in Tables 6-9 and 6-10.

**TABLE 6-9. CAPITAL AND ANNUAL COSTS
FOR SCR USED DOWNSTREAM OF WATER OR STEAM INJECTION (1990 \$)**

Model plant	GT model	Total capital investment, \$ ^a	Operating labor, \$	Supervisory labor, \$	Maintenance labor & materials, \$	Catalyst replacement, \$	Catalyst disposal, \$	Ammonia, \$	Dilution steam, \$	Performance loss, \$	Blower (if needed), \$	Overhead, \$	Taxes, insurance & admin, \$	Capital recovery, \$	Total annual cost, \$
CON-G-W-3.3	Centaur T4500	622,000	25,600	3,840	29,900	52,600	963	2,980	1,770	7,850	785	35,600	24,900	55,600	242,000
CON-G-W-4.0	501-KB5	658,000	25,600	3,840	30,800	56,000	1,180	3,570	2,130	9,600	960	36,100	26,300	58,600	255,000
CON-G-W-22.7	LM2500	1,590,000	25,600	3,840	54,100	144,000	6,680	14,700	8,740	54,400	5,440	50,100	63,600	137,000	568,000
CON-G-W-26.8	MS5001P	1,790,000	25,600	3,840	59,300	163,000	7,900	22,400	13,300	64,300	6,430	53,200	71,600	154,000	645,000
CON-G-W-83.3	ABB GT11N	4,600,000	25,600	3,840	130,000	429,000	24,500	29,600	17,600	200,000	20,000	95,700	184,000	391,000	1,550,000
CON-G-W-84.7	MS7001E	4,670,000	25,600	3,840	132,000	435,000	25,000	62,000	36,900	203,000	20,300	96,900	187,000	397,000	1,620,000
CON-G-S-4.0	501-KB5	658,000	25,600	3,840	30,800	56,000	1,180	3,570	2,130	9,600	960	36,100	26,300	58,600	255,000
CON-G-S-22.7	LM2500	1,590,000	25,600	3,840	54,100	144,000	6,680	7,110	4,240	54,400	5,440	50,100	63,600	137,000	556,000
CON-G-S-26.8	MS5001P	1,790,000	25,600	3,840	59,300	163,000	7,900	22,400	13,300	64,300	6,430	53,200	71,600	154,000	645,000
CON-G-S-34.4	LM5000	2,170,000	25,600	3,840	68,900	199,000	10,100	10,700	6,380	82,700	8,270	59,000	86,800	186,000	747,000
CON-G-S-83.3	ABB GT11N	4,600,000	25,600	3,840	130,000	429,000	24,500	61,000	36,300	200,000	20,000	95,700	184,000	391,000	1,600,000
CON-G-S-84.7	MS7001E	4,670,000	25,600	3,840	132,000	435,000	25,000	62,000	36,900	203,000	20,300	96,900	187,000	397,000	1,620,000
CON-G-S-161	MS7001F	8,460,000	25,600	3,840	227,000	794,000	47,400	108,000	64,200	386,000	38,600	154,000	338,000	717,000	2,900,000
CON-O-W-3.3	Centaur T4500	622,000	25,600	3,840	29,900	52,600	963	3,890	2,320	7,850	785	35,600	24,900	55,600	244,000
CON-O-W-26.3	MS5001P	1,770,000	25,600	3,840	58,700	161,000	7,750	32,400	19,300	63,100	6,310	52,900	70,800	152,000	654,000
CON-O-W-83.3	MS7001E	4,600,000	25,600	3,840	130,000	429,000	24,500	90,000	53,800	200,000	20,000	95,700	184,000	391,000	1,650,000
PKR-G-W-3.3	Centaur T4500	622,000	6,400	960	7,470	13,100	241	740	440	1,960	196	8,900	24,900	75,300	141,000
PKR-G-W-26.8	MS5001P	1,790,000	6,400	960	14,800	40,800	1,970	5,600	3,330	16,100	1,610	13,300	71,600	215,000	391,000
PKR-G-W-84.7	MS7001E	4,670,000	6,400	960	32,900	109,000	6,240	15,500	9,240	50,800	5,080	24,200	187,000	560,000	1,010,000
PKR-O-W-3.3	Centaur T4500	622,000	6,400	960	7,470	13,100	241	970	580	1,960	196	8,900	24,900	75,300	141,000
PKR-O-W-26.3	MS5001P	1,770,000	6,400	960	14,700	40,200	1,940	8,100	4,830	15,800	1,580	13,200	70,800	213,000	392,000
PKR-O-W-84.7	MS7001E	4,600,000	6,400	960	32,500	107,000	6,140	22,500	13,440	50,000	5,000	23,900	184,000	552,000	1,000,000
STD-O-W-1.1	Saturn T1500	515,000	3,200	480	3,400	5,310	41.6	185	158	339	33.9	4,250	20,600	65,100	103,000
STD-O-E-28.0	TPM FT4	1,850,000	3,200	480	60,800	21,100	1,030	3,180	2,960	8,400	840	38,700	74,000	233,000	448,000

^aCosts shown are for SCR systems used downstream of gas turbines with wet injection to achieve controlled NO_x emission levels at the inlet to the SCR as shown in Table 6-6.

TABLE 6-10. CAPITAL AND ANNUAL COSTS FOR SCR USED DOWNSTREAM OF LOW-NO_x COMBUSTION

Model plant ^a	GT model	Total capital invest., \$ ^b	Operating labor, \$	Supervisory labor, \$	Maintenance labor & materials, \$	Catalyst replacement, \$	Catalyst disposal, \$	Ammonia, \$	Dilution steam, \$	Performance loss, \$	Blower (if needed), \$	Overhead, \$	Taxes, insurance & admin., \$	Capital recovery, \$	Total annual cost, \$
CON-L-3.3-42	Centaur T4500	622,000	25,600	3,840	29,900	52,700	970	2,980	1,770	7,920	790	35,600	24,900	55,500	242,000
CON-L-4.0-42	Centaur 'H'	658,000	25,600	3,840	30,800	56,000	1,180	3,470	2,070	9,600	960	36,100	26,300	58,600	255,000
CON-L-4.5-42	Taurus	683,000	25,600	3,840	31,400	58,400	1,330	3,800	2,270	10,800	1,080	36,500	27,300	60,700	263,000
CON-L-8.8-42	Mars T12000	896,000	25,600	3,840	36,800	78,600	2,590	6,850	4,080	21,100	2,110	39,700	35,800	78,600	336,000
CON-L-10-42	Mars T14000	956,000	25,600	3,840	38,300	84,200	2,950	7,530	4,490	24,000	2,400	40,600	38,200	83,700	356,000
CON-L-3.3-25	Centaur T4500	622,000	25,600	3,840	29,900	52,700	970	1,440	860	7,920	790	35,600	24,900	55,500	240,000
CON-L-4.0-25	Centaur 'H'	658,000	25,600	3,840	30,800	56,000	1,180	1,680	1,000	9,600	960	36,100	26,300	58,600	252,000
CON-L-4.5-25	Taurus	683,000	25,600	3,840	31,400	58,400	1,330	1,840	1,100	10,800	1,080	36,500	27,300	60,700	260,000
CON-L-8.8-25	Mars T12000	896,000	25,600	3,840	36,800	78,600	2,590	3,320	1,980	21,100	2,110	39,700	35,800	78,600	330,000
CON-L-10-25	Mars T14000	956,000	25,600	3,840	38,300	84,200	2,950	3,650	2,180	24,000	2,400	40,600	38,200	83,700	350,000
CON-L-39-25	MS6000	2,400,000	25,600	3,840	74,600	221,000	11,490	14,300	8,550	93,600	9,360	62,400	96,000	205,000	826,000
CON-L-83-25	ABB GT11N	4,600,000	25,600	3,840	130,000	429,000	24,540	29,600	17,600	200,000	20,000	95,700	184,000	391,000	1,550,000
CON-L-85-25	MS7001E	4,670,000	25,600	3,840	132,000	435,000	24,960	30,100	17,900	203,000	20,300	96,900	186,800	397,000	1,570,000
PKR-L-3.3-42	Centaur T4500	622,000	6,400	960	7,480	55,100	2,870	740	440	1,980	200	8,900	24,900	54,300	164,000
PKR-L-4.0-42	Centaur 'H'	658,000	6,400	960	7,700	107,000	6,140	870	520	2,400	240	9,000	26,300	33,200	201,000
PKR-L-4.5-42	Taurus	683,000	6,400	960	7,860	109,000	6,240	950	570	2,700	270	9,100	27,300	35,500	207,000
PKR-L-8.8-42	Mars T12000	896,000	6,400	960	9,200	9,300	0	1,710	1,020	5,280	530	9,900	35,800	113,000	193,000
PKR-L-10-42	Mars T14000	956,000	6,400	960	9,580	13,200	240	1,880	1,120	6,000	600	10,200	38,200	119,000	207,000
PKR-L-3.3-25	Centaur T4500	623,000	6,400	960	7,480	14,600	330	360	210	1,980	200	8,900	24,900	74,600	141,000
PKR-L-4.0-25	Centaur 'H'	658,000	6,400	960	7,700	19,600	650	420	250	2,400	240	9,000	26,300	76,800	151,000
PKR-L-4.5-25	Taurus	683,000	6,400	960	7,860	21,100	740	460	270	2,700	270	9,100	27,300	79,300	156,000
PKR-L-8.8-25	Mars T12000	896,000	6,400	960	9,200	9,300	0	830	490	5,280	530	9,900	35,800	113,000	192,000
PKR-L-10-25	Mars T14000	956,000	6,400	960	9,580	13,200	240	910	540	6,000	600	10,200	38,200	119,000	206,000
PKR-L-39-25	MS6000	2,400,000	6,400	960	18,600	14,000	290	3,590	2,140	23,400	2,340	15,600	96,000	309,000	492,000
PKR-L-83-25	ABB GT11N	4,600,000	6,400	960	32,500	14,600	330	7,390	4,410	50,000	5,000	23,900	184,000	598,000	927,000
PKR-L-85-25	MS7001E	4,670,000	6,400	960	32,900	19,600	650	7,520	4,480	50,800	5,080	24,200	186,800	604,000	943,000

^aSee Table 6-7 for model plant legend.

^bCosts shown are for SCR systems used downstream of gas turbines with dry low-NO_x combustion to achieve controlled NO_x emission levels at the inlet to the SCR as shown in Table 6-7.

ii. Annual Costs

Total annual costs for SCR control were developed following standard EPA procedures described in the OAQPS Control Cost Manual for other types of add-on air pollution control devices (APCD's). Information about annual costs was obtained from the same sources that provided capital costs.²⁷⁻³¹ Total annual costs consist of direct and indirect costs; parameters that make up these categories and the equations for estimating the costs are

presented in Table 6-8 and are discussed below. The annual costs are shown in Tables 6-9 and 6-10 for injection and dry low-NO_x combustion, respectively, for each of the model plants.

(1) Operating and Supervisory Labor. Information about operating labor requirements was unavailable. Most facilities have fully automated controls and monitoring/recording equipment, which minimizes operator attention. Therefore, it was assumed that 1 hr of operator attention would be required during an 8-hr shift, regardless of turbine size. This operating labor requirement is at the low end of the range recommended in the OAQPS Control Cost Manual for other types of APCD's.⁷ Operator wage rates were estimated to be \$25.60/hr in 1990, based on escalating the costs presented in Reference 2 by 5 percent per year to account for inflation. Supervisory labor costs were estimated to be 15 percent of the operating labor costs, consistent with the OAQPS Control Cost Manual.

(2) Maintenance Labor and Materials. Combined maintenance labor and materials costs for 14 facilities were obtained from four articles, but almost half of the data (6 facilities) were provided by one source.²⁷⁻³⁰ The costs were escalated to 1990 dollars assuming an inflation rate of 5 percent per year. All of the data are for facilities that burn natural gas. Provided that ammonium salt formation is avoided by limiting ammonia slip and sulfur content, the cost for operation with natural gas should also apply for distillate oil fuel.³² Therefore, it was assumed that the cost data also apply to SCR control for turbines that fire distillate oil fuel. The costs were plotted versus the turbine size, and least-squares linear regression was used to determine the equation of the line through the data (see Appendix B). This equation, shown in Table 6-8, was used to estimate the maintenance labor and materials costs shown in Table 6-9 for the model plants.

(3) Catalyst Replacement. Replacement costs were obtained for nine gas turbine facilities, and combined replacement and disposal costs were obtained for another six gas turbine facilities.²⁷⁻³⁰ The disposal costs were estimated for the six

facilities as described below and in Appendix B. The replacement costs for these six facilities were then estimated by subtracting the estimated disposal costs from the combined costs. A catalyst life of 5 years was used. All replacement costs were escalated to 1990 dollars assuming a 5 percent annual inflation rate.

The estimated 1990 replacement costs were plotted versus the turbine size, and least-squares linear regression was used to determine the equation of the line through the data (see Appendix B). This equation is shown in Table 6-8 and was used to estimate the catalyst replacement costs shown in Table 6-9 for the model plants.

(4) Catalyst Disposal. Catalyst disposal costs were estimated based on a unit disposal cost of \$15/ft³, which was obtained from a zeolite catalyst vendor.³² This cost was used for each model plant, but the disposal cost may in fact be higher for catalysts that contain heavy metals and are classified as hazardous wastes. The catalyst volume for each model plant was estimated based on information about the catalyst volume for one facility and the assumption that there is a direct relationship between the catalyst volume and the turbine output (i.e., the design space velocity is the same regardless of the SCR size). At one facility, 175 m³ (6,180 ft³) of catalyst is used in the SCR with an 83 MW (111,000 hp) turbine.³³ The disposal cost for this catalyst would be \$92,700, using a cost of \$15/ft³.

(5) Ammonia. The annual ammonia (NH₃) requirement is calculated from the annual NO_x reduction achieved by the SCR system. Based on an NH₃/NO_x molar ratio of 1.0, the annual ammonia requirement, in tons, would equal the annual NO_x reduction, in tons, multiplied by the ratio of the molecular weights for NH₃ and NO_x. Anhydrous ammonia with a unit cost of \$360/ton was used.^{34,35} The equation to calculate the annual cost for ammonia is shown in Table 6-8.

(6) Dilution Steam. As indicated in Section 5.3.1, steam is used to dilute the ammonia to about 5 percent by volume before injection into the HRSG. According to the OAQPS Control Cost

Manual, the cost to produce steam, or to purchase it, is about \$6/1,000 lb.

(7) Electricity. Electricity requirements to operate such equipment as ammonia pumps and ventilation fans is believed to be small. For one facility, the cost of electricity to operate these components was estimated to make up less than 1 percent of the total annual cost, but it is not clear that the number and size of the fans and pumps represent a typical installation.²⁷ This cost for electricity is expected to be minor, however, for all installations and was not included in this analysis.

For high-temperature catalysts installed upstream of the HRSG, a blower may be required to inject ambient air into the exhaust to regulate the temperature and avoid temperature excursions above the catalyst design temperature range. The cost to operate the blower is calculated to be 10 percent of the fuel penalty.³⁵

(8) Performance Loss. The performance loss due to backpressure from the SCR is approximately 0.5 percent of the turbine's design output.³⁴⁻³⁶ To make up for this lost output, it was assumed that electricity would have to be purchased at a cost of \$0.06/kWH, as indicated in Table 6-3.

(9) Production Loss. No costs for production losses were included in this analysis. It was assumed that scheduled inspections, cleaning, and other maintenance will coincide with the 760 hr/yr of expected or scheduled downtime. It should be recognized that adding the SCR system increases the overall system complexity and the probability of unscheduled outages. This factor should be taken into account when considering the addition of an SCR system.

(10) Overhead. Standard EPA procedures for estimating annual control costs include overhead costs that are equal to 60 percent of all labor and maintenance material costs.

(11) Property Taxes, Insurance, and Administration. According to standard EPA procedures for estimating annual control costs, property taxes, insurance, and administration

costs are equal to 4 percent of the total capital investment for the control system.

(12) Capital Recovery. The CRF for SCR was estimated to be 0.13147 based on the assumption that the equipment life is 15 years and the interest rate is 10 percent.

iii. Cost Effectiveness for SCR

As indicated in Section 5.4, virtually all gas turbine installations using SCR to reduce NO_x emissions also incorporate wet injection or low-NO_x combustors. The NO_x emission levels into the SCR, therefore, were in all cases taken to be equal to the controlled NO_x emission levels shown for these control techniques in Tables 6-6 and 6-7. The most common controlled NO_x emission limit for gas-fired SCR applications is 9 ppmv, referenced to 15 percent oxygen. The capital costs used in this analysis are expected to correspond to SCR systems sized to reduce controlled NO_x emissions ranging from 25 to 42 ppmv from gas-fired turbines to a controlled level of approximately 9 ppmv downstream of the SCR. Based on the controlled NO_x emission limits established by the Northeast States for Coordinated Air Use Management (NESCAUM), shown in Table 5-3, these SCR systems would reduce NO_x emissions to 18 ppmv for oil-fired applications. Cost-effectiveness figures for SCR in this analysis are therefore calculated based on controlled NO_x emission levels of 9 and 18 ppmv, corrected to 15 percent oxygen, for gas- and oil-fired SCR model plants, respectively.

Cost effectiveness for SCR used downstream of wet injection or dry low-NO_x combustion is shown in Tables 6-11

TABLE 6-11. COST-EFFECTIVENESS SUMMARY FOR SCR USED DOWNSTREAM OF GAS TURBINES WITH WET INJECTION (1990 \$)

Model plant	GT model	Turbine output, MW	NO _x emissions ^a				Total NO _x removed, tons/yr	Total annual cost, \$ ^c	Cost effective- ness, \$/ton
			Inlet to SCR		Downstream of SCR				
			ppmv ^b	tons/yr	ppmv	tons/yr			
CON-G-W-3.3	Centaur T4500	3.3	42	28.5	9.0	6.10	22.4	242,000	10,800
CON-G-W-4.0	501-KB5	4.0	42	34.2	9.0	7.32	26.8	255,000	9,500
CON-G-W-22.7	LM2500	22.7	42	140	9.0	30.0	110	568,000	5,160
CON-G-W-26.8	MS5001P	26.8	42	214	9.0	45.8	168	645,000	3,840
CON-G-W-83.3	ABB GT11N	83.3	25	347	9.0	125	222	1,550,000	6,980
CON-G-W-84.7	MS7001E	84.7	42	593	9.0	127	466	1,620,000	3,480
CON-G-S-4.0	501-KB5	4.0	42	34.2	9.0	7.32	26.8	255,000	9,500
CON-G-S-22.7	LM2500	22.7	25	83.5	9.0	30.0	53.4	556,000	10,400
CON-G-S-26.8	MS5001P	26.8	42	214	9.0	45.8	168	645,000	3,840
CON-G-S-34.4	LM5000	34.4	25	126	9.0	45.2	80.4	747,000	9,290
CON-G-S-83.3	ABB GT11N	83.3	42	583	9.0	125	458	1,600,000	3,490
CON-G-S-84.7	MS7001E	84.7	42	593	9.0	127	466	1,620,000	3,480
CON-G-S-161	MS7001F	161	42	1,030	9.0	221	809	2,900,000	3,580
CON-O-W-3.3	Centaur T4500	3.3	60	41.8	18.0	12.5	29.3	244,000	8,340
CON-O-W-26.3	MS5001P	26.3	65	337	18.0	93.3	244	654,000	2,690
CON-O-W-83.3	MS7001E	83.3	65	938	18.0	260	678	1,650,000	2,430
PKR-G-W-3.3	Centaur T4500	3.3	42	7.12	9.0	1.52	5.59	141,000	25,200
PKR-G-W-26.8	MS5001P	26.8	42	53.5	9.0	11.5	42.0	391,000	9,310
PKR-G-W-84.7	MS7001E	84.7	42	148	9.0	31.8	116	1,010,000	8,670
PKR-O-W-3.3	Centaur T4500	3.3	60	10.5	18.0	3.14	7.32	141,000	19,300
PKR-O-W-26.3	MS5001P	26.3	65	84.2	18.0	23.3	60.9	392,000	6,440
PKR-O-W-84.7	MS7001E	84.7	65	234	18.0	64.9	169	1,000,000	5,900
STD-O-W-1.1	Saturn T1500	1.1	60	1.99	18.0	0.60	1.39	103,000	74,000
STD-O-E-28.0	TPM FT4	28.0	50	37.3	18.0	13.4	23.9	448,000	18,800

^aExample NO_x emission calculations are shown in Appendix A.

^bReferenced to 15 percent oxygen.

^cFrom Table 6-9.

**TABLE 6-12. COST-EFFECTIVENESS SUMMARY FOR SCR USED DOWNSTREAM
OF DRY LOW-NO_x COMBUSTION (1990 \$)**

Model plant ^a	GT model	Turbine output, MW	NO _x emissions ^b						Total NO _x removed, tons/yr	Total annual cost, \$ ^d	Cost effective- ness, \$/ton
			Uncontrolled		Inlet to SCR		Downstream of SCR				
							ppmv				
			tons/yr	ppmv	tons/yr	ppmv	tons/yr	ppmv			
CON-L-3.3-42	Centaur T4500	3.3	130	88.1	42	28.5	9.0	6.1	22.4	242,000	10,800
CON-L-4.0-42	Centaur 'H'	4.0	105	83.0	42	33.2	9.0	7.1	26.1	255,000	9,780
CON-L-4.5-42	Taurus	4.5	114	98.7	42	36.4	9.0	7.8	28.6	263,000	9,200
CON-L-8.8-42	Mars T12000	8.8	178	278	42	65.5	9.0	14.0	51.5	336,000	6,530
CON-L-10-42	Mars T14000	10.0	199	341	42	72.1	9.0	15.4	56.6	356,000	6,290
CON-L-3.3-25	Centaur T4500	3.3	130	88.1	25	16.9	9.0	6.1	10.8	240,000	22,100
CON-L-4.0-25	Centaur 'H'	4.0	105	83.0	25	19.8	9.0	7.1	12.6	252,000	19,900
CON-L-4.5-25	Taurus	4.5	114	98.7	25	21.7	9.0	7.8	13.9	260,000	18,800
CON-L-8.8-25	Mars T12000	8.8	178	278	25	39.0	9.0	14.0	25.0	330,000	13,200
CON-L-10-25	Mars T14000	10.0	199	341	25	42.9	9.0	15.4	27.5	350,000	12,800
CON-L-39-25	MS6000	39.0	220	1,480	25	168	9.0	61	108	826,000	7,660
CON-L-83-25	ABB GT11N	83.3	390	5,420	25	347	9.0	125	222	1,550,000	6,970
CON-L-85-25	MS7001E	84.7	154	2,180	25	353	9.0	127	226	1,570,000	6,940
PKR-L-3.3-42	Centaur T4500	3.3	130	22.0	42	7.12	9.0	1.52	5.6	164,000	29,300
PKR-L-4.0-42	Centaur 'H'	4.0	105	20.7	42	8.30	9.0	1.78	6.5	201,000	30,800
PKR-L-4.5-42	Taurus	4.5	114	24.7	42	9.09	9.0	1.95	7.1	207,000	29,000
PKR-L-8.8-42	Mars T12000	8.8	178	69.4	42	16.4	9.0	3.5	12.9	193,000	15,000
PKR-L-10-42	Mars T14000	10.0	199	85.4	42	18.0	9.0	3.9	14.2	207,000	14,600
PKR-L-3.3-25	Centaur T4500	3.3	130	22.0	25	4.24	9.0	1.52	2.7	141,000	52,000
PKR-L-4.0-25	Centaur 'H'	4.0	105	20.7	25	4.94	9.0	1.78	3.2	151,000	47,800
PKR-L-4.5-25	Taurus	4.5	114	24.7	25	5.41	9.0	1.95	3.5	156,000	45,000
PKR-L-8.8-25	Mars T12000	8.8	178	69.4	25	9.75	9.0	3.51	6.2	192,000	30,800
PKR-L-10-25	Mars T14000	10.0	199	85.4	25	10.7	9.0	3.9	6.9	206,000	30,000
PKR-L-39-25	MS6000	39.0	220	371	25	42.1	9.0	15.2	26.9	492,000	18,300
PKR-L-83-25	ABB GT11N	83.3	390	1,350	25	86.8	9.0	31.3	55.6	927,000	16,700
PKR-L-85-25	MS7001E	84.7	154	540	25	88.3	9.0	31.8	56.5	943,000	16,700

^aSee Table 6-7 for model plant legend.

^bExample NO_x emission calculations are shown in Appendix A.

^cReferenced to 15 percent oxygen.

^dFrom Table 6-10.

model plants using water or steam injection, the cost effectiveness for SCR ranges from approximately \$3,500 to \$10,800 per ton of NO_x removed.

The cost-effectiveness range for SCR installed downstream of continuous-duty, natural gas-fired turbines from 3 to 10 MW (4,000 to 13,400 hp) using dry low-NO_x combustion is \$6,290 to \$10,800 per ton of NO_x removed for an inlet NO_x emission level of 42 ppmv. The cost-effectiveness range for SCR increases for an

inlet NO_x emission level of 25 ppmv due to the lower NO_x reduction efficiency. For an inlet NO_x level of 25 ppmv, the cost effectiveness ranges from \$12,800 to \$22,100 per ton of NO_x removed for 3 to 10 MW (4,000 to 13,400 hp) turbines and decreases to \$6,940 to \$7,660 per ton of NO_x removed for larger turbines ranging from 39 to 85 MW (52,300 to 114,000 hp). As these ranges indicate, the cost effectiveness for SCR is affected by the inlet NO_x emission level and not the type of combustion control technique used for the turbine. The cost effectiveness for continuous-duty, oil-fired model plants ranges from approximately \$2,450 to \$8,350 per ton of NO_x removed. The SCR cost-effectiveness range for oil-fired applications is lower than that for gas-fired installations in this cost analysis because the same capital costs were used for both fuels (capital costs were not available for applications using only distillate oil fuel). The percent NO_x reduction for oil-fired applications is higher, so the resulting cost-effectiveness figures for oil-fired applications are lower. It should be noted that this higher NO_x reduction for oil-fired applications may require a larger catalyst reactor, at a higher capital cost. As a result, the cost-effectiveness figures may actually be higher than those shown in Table 6-11 for oil-fired applications.

The cost-effectiveness figures are higher for smaller gas turbines because the fixed capital costs associated with the installation of an SCR system have the greatest impact on smaller gas turbines. Cost-effectiveness figures increase as annual operating hours decrease. For turbines operating 2,000 hours per year, cost-effectiveness figures are more than double those for continuous-duty model plants, and they increase even further for model plants operating 1,000 hr/yr.

Because virtually all SCR systems are installed downstream of controlled gas turbines, combined cost-effectiveness figures for wet injection plus SCR and also dry low-NO_x combustion plus SCR have been calculated and are shown in Tables 6-13

TABLE 6-13. COMBINED COST-EFFECTIVENESS SUMMARY FOR WET INJECTION PLUS SCR (1990 \$)

Model plant	GT model	Turbine output MW	NO _x emissions ^a						Total NO _x removed, tons/yr ^c	Total annual cost, \$ ^c	Cost effective- ness, \$/ton ^c
			Uncontrolled		Inlet to SCR		Downstream of SCR				
			ppmv ^b	tons/yr	ppmv	töns/yr	ppmv	töns/yr			
CON-G-W-3.3	Centaur T4500	3.3	130	88.1	42	28.5	9.0	6.10	82.0	366,000	4,460
CON-G-W-4.0	501-KB5	4.0	155	126	42	34.2	9.0	7.32	119	417,000	3,510
CON-G-W-22.7	LM2500	22.7	174	581	42	140	9.0	30	551	1,000,000	1,820
CON-G-W-26.8	MS5001P	26.8	142	723	42	214	9.0	46	677	1,220,000	1,800
CON-G-W-83.3	ABB GT11N	83.3	390	5,410	25	347	9.0	125	5,290	4,460,000	843
CON-G-W-84.7	MS7001E	84.7	154	2,170	42	593	9.0	127	2,040	3,100,000	1,520
CON-G-S-4.0	501-KB5	4.0	155	126	42	34.2	9.0	7.32	119	423,000	3,560
CON-G-S-22.7	LM2500	22.7	174	581	25	83.5	9.0	30.0	551	977,000	1,770
CON-G-S-26.8	MS5001P	26.8	142	723	42	214	9.0	45.8	677	1,130,000	1,670
CON-G-S-83.3	LM5000	34.4	185	930	25	126	9.0	45.2	884	1,440,000	1,630
CON-G-S-84.7	ABB GT11N	83.3	390	5,410	42	583	9.0	125	5,290	3,410,000	645
CON-G-S-84.7	MS7001E	84.7	154	2,170	42	593	9.0	127	2,040	2,780,000	1,360
CON-G-S-161	MS7001F	161	210	5,150	42	1,030	9.0	220	4,930	4,870,000	988
CON-O-W-3.3	Centaur T4500	3.3	179	125	60	42	18.0	12.5	112	387,000	3,450
CON-O-W-26.3	MS5001P	26.3	211	1,090	65	337	18.0	93.3	997	1,410,000	1,410
CON-O-W-83.3	MS7001E	83.3	228	3,290	65	938	18.0	260	3,030	3,230,000	1,070
PKR-G-W-3.3	Centaur T4500	3.3	130	22.0	42	7.1	9.0	1.5	20.5	222,000	10,800
PKR-G-W-26.8	MS5001P	26.8	142	181	42	53.5	9.0	11.5	169	690,000	4,080
PKR-G-W-84.7	MS7001E	84.7	154	543	42	148	9.0	31.8	512	1,710,000	3,340
PKR-O-W-3.3	Centaur T4500	3.3	179	31.2	60	10	18.0	3.14	28.1	228,000	8,130
PKR-O-W-26.3	MS5001P	26.3	211	273	65	84	18.0	23.3	250	751,000	3,000
PKR-O-W-84.7	MS7001E	84.7	228	822	65	234	18.0	64.9	757	1,710,000	2,260
STD-O-W-1.1	Saturn T1500	1.1	150	4.97 122	60	1.99	18.0	0.60	4.4	152,000	34,700
STD-O-E-28.0	TPM FT4	28.0	150	150	50	37.3	18.0	13.4	109	604,000	5,563

^aExample NO_x emission calculations are shown in Appendix A.

^bReferenced to 15 percent oxygen.

^cTotal for both wet injection plus SCR control techniques.

TABLE 6-14. COMBINED COST-EFFECTIVENESS SUMMARY FOR DRY LOW-NO_x COMBUSTION PLUS SCR (1990 \$)

Model plant	GT model	Turbine output MW	Annual operating hours	NO _x emissions ^a						Total NO _x removed, tons/yr ^c	Total annual cost, \$ ^c	Cost effective- ness, \$/ton ^c		
				Uncontrolled		Inlet to SCR		Downstream of SCR						
				ppmv ^b		tohs/yr		ppmv					tohs/yr	
				tons/yr	ppmv	tohs/yr	ppmv	tohs/yr	ppmv				tohs/yr	
CON-L-3-3-42	Centaur T4500	3.3	8,000	130	88.1	42	28.5	9.0	6.1	82.0	291,000	3,536		
CON-L-4-0-42	Centaur 'H'	4.0	8,000	105	83.0	42	33.2	9.0	7.1	75.8	308,000	4,064		
CON-L-4-5-42	Taurus	4.5	8,000	114	98.7	42	36.4	9.0	7.8	90.9	319,000	3,516		
CON-L-8-8-42	Mars T12000	8.8	8,000	178	278	42	65.5	9.0	14.0	264	428,000	1,621		
CON-L-10-42	Mars T14000	10.0	8,000	199	341	42	72.1	9.0	15.4	326	451,000	1,388		
CON-L-3-3-25	Centaur T4500	3.3	8,000	130	88.1	25	16.9	9.0	6.1	82.0	289,000	3,526		
CON-L-4-0-25	Centaur 'H'	4.0	8,000	105	83.0	25	19.8	9.0	7.1	75.8	305,000	4,020		
CON-L-4-5-25	Taurus	4.5	8,000	114	98.7	25	21.7	9.0	7.8	90.9	316,000	3,470		
CON-L-8-8-25	Mars T12000	8.8	8,000	178	278	25	39.0	9.0	14.0	264	422,000	1,604		
CON-L-10-25	Mars T14000	10.0	8,000	199	341	25	42.9	9.0	15.4	326	445,000	1,370		
CON-L-39-25	MS6000	39.0	8,000	220	1,480	25	168	9.0	60.6	1,420	1,010,000	711		
CON-L-83-25	ABB GT11N	83.3	8,000	390	5,420	25	347	9.0	125	5,290	1,840,000	348		
CON-L-85-25	MS7001E	84.7	8,000	154	2,180	25	353	9.0	127	2,050	1,850,000	906		
PKR-L-3-3-42	Centaur T4500	3.3	2,000	130	22.0	42	7.1	9.0	1.5	20.5	213,000	10,400		
PKR-L-4-0-42	Centaur 'H'	4.0	2,000	105	20.7	42	8.3	9.0	1.8	19.0	254,000	13,400		
PKR-L-4-5-42	Taurus	4.5	2,000	114	24.7	42	9.1	9.0	1.9	22.7	263,000	11,600		
PKR-L-8-8-42	Mars T12000	8.8	2,000	178	69.4	42	16.4	9.0	3.5	65.9	285,000	4,320		
PKR-L-10-42	Mars T14000	10.0	2,000	199	85.4	42	18.0	9.0	3.9	81.5	302,000	3,710		
PKR-L-3-3-25	Centaur T4500	3.3	2,000	130	22.0	25	4.2	9.0	1.5	20.5	190,000	9,300		
PKR-L-4-0-25	Centaur 'H'	4.0	2,000	105	20.7	25	4.9	9.0	1.8	19.0	204,000	10,800		
PKR-L-4-5-25	Taurus	4.5	2,000	114	24.7	25	5.4	9.0	1.9	22.7	212,000	9,300		
PKR-L-8-8-25	Mars T12000	8.8	2,000	178	69.4	25	9.8	9.0	3.5	65.9	284,000	4,300		
PKR-L-10-25	Mars T14000	10.0	2,000	199	85.4	25	10.7	9.0	3.9	81.5	301,000	3,700		
PKR-L-39-25	MS6000	39.0	2,000	220	371	25	42.1	9.0	15.2	355	680,000	1,918		
PKR-L-83-25	ABB GT11N	83.3	2,000	390	1,350	25	86.8	9.0	31.3	1,320	1,220,000	924		
PKR-L-85-25	MS7001E	84.7	2,000	154	540	25	88.3	9.0	31.8	508	1,220,000	2,400		

^aExample NO_x emission calculations are shown in Appendix A.

^bReferenced to 15 percent oxygen.

^cTotal for both dry low-NO_x combustion plus SCR control techniques.

and 6-14, specific to these combined cost effectiveness

figures are calculated by dividing the sum of the total annual costs by the

sum of the annual reduction of NO_x emissions for the combined emission control techniques. For continuous-duty, natural gas-fired model plants, the combined cost-effectiveness figures for wet injection plus SCR range from approximately \$650 to \$4,500 per ton of NO_x removed. For continuous-duty, oil-fired model plants, the combined cost effectiveness ranges from approximately \$1,100 to \$3,550 per ton of NO_x removed. The combined cost-effectiveness figures for dry low-NO_x combustion plus SCR for continuous-duty, natural gas-fired model plants range from approximately \$350 to \$3,550 per ton of NO_x removed.

The combined cost-effectiveness figures increase with decreasing turbine size and annual operating hours. Data were not available to quantify the wet injection requirements and controlled emissions levels for oil-fired turbines with low-NO_x combustors, so cost-effectiveness figures were not tabulated for this control scenario.

d. OFFSHORE TURBINES

The only available information about the cost of NO_x controls for offshore gas turbines was presented in a report prepared for the Santa Barbara County Air Pollution Control District (SBCAPCD) in California.³⁷ The performance and cost of about 20 NO_x control techniques for a 2.8 MW (3,750 hp) turbine were described in the report. Wet injection and SCR were included in the analysis; low-NO_x combustors were not. The costs from the report are presented in Table 6-15

**TABLE 6-15. PROJECTED WET INJECTION AND SCR COSTS
FOR AN OFFSHORE GAS TURBINE^a**

	Wet injection costs	SCR costs
Capital cost, \$	70,000	585,000
Annual costs, \$/yr		
Ammonia	N/A ^b	3,050 ^c
Catalyst replacement	N/A	28,000
Operating and maintenance ^d	24,600	18,000
Fuel penalty ^e	10,500	5,000
Capital recovery ^f	14,000	117,000
Total annual costs, \$/yr	49,100	171,000

^aCosts are for a 2.8 MW gas turbine and are obtained from Reference 37.

^bN/A = Not applicable.

^cAmmonia cost is based on \$150/ton and 0.4 lb NH₃/lb NO_x.

^dOperating and maintenance cost for SCR is estimated as 3 percent of the total capital investment.

^eFuel penalty is estimated as 2 percent of the annual fuel consumption for wet injection and 1 percent for SCR.

^fCapital recovery is estimated based on an equipment life of 8 years and an interest rate of 13 percent.

without adjustment because there is insufficient cost information to know what adjustments need to be made. Additionally, insufficient information is available to scale up these costs for larger turbines. The water and steam injection costs and SCR costs for offshore applications are discussed in Sections 6.4.1 and 6.4.2, respectively.

i. Wet Injection

The report prepared for SBCAPCD assumed water injection costs are the same as steam injection costs. The report did not describe the components in the capital cost analysis for these injection systems, but the results are much lower than those that

would be estimated by the procedures described in Section 6.1.1 of this report. The authors may have assumed that the engine-mounted injection equipment cost was included in the turbine capital cost and that a less rigorous water treatment process is installed. Annual costs are also much lower than those that would be estimated by the procedures described in Section 6.1.2 of this report. There are at least three reasons for the difference: (1) the low capital cost leads to a low CRF, even though the turbine life was assumed to be only 8 years; (2) overhead costs and taxes, insurance, and administration costs are not considered; and (3) the capacity factor is only 50 percent (i.e., about 4,400 hr/yr, vs. 8,000 hr/yr, as in Section 6.1.2). The turbine life was only 8 years, which may correspond to a typical service life of an offshore platform.

ii. Selective Catalytic Reduction

The total capital costs presented in the report for SBCAPCD are similar to those that would be estimated by the procedures in Section 6.2.1 of this report. However, it appears that \$150,000 of the total in Reference 37 is for structural modifications to the platform and \$75,000 is for retrofit installation. When the difference in the load factor is taken into account, some of the annual costs are similar to those that would be estimated by the procedures in Section 6.2.2 for a similarly sized turbine. The catalyst replacement cost, however, is much lower; neither the type of catalyst nor the replacement frequency were identified. Ammonia costs are lower because the uncontrolled NO_x emission level was assumed to be 110 ppmv instead of 150 ppmv and because a unit cost of \$150/ton was used instead of \$400/ton. The reference does not indicate whether or not catalyst disposal, overhead, taxes, freight, and administration costs were considered. Capital recovery costs are higher because the equipment life is assumed to be only 8 years on the offshore platform.

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7..0 ENVIRONMENTAL AND ENERGY IMPACTS

This chapter presents environmental and energy impacts for the nitrogen oxide (NO_x) emissions control techniques described in Chapter 5.0. These control techniques are water or steam injection, dry low- NO_x combustors, and selective catalytic reduction (SCR). The impacts of the control techniques on air pollution, solid waste disposal, water pollution, and energy consumption are discussed.

The remainder of this chapter is organized in five sections. Section 7.1 presents the air pollution impacts; Section 7.2 presents the solid waste disposal impacts; Section 7.3 presents the water pollution impacts; and Section 7.4 presents the energy consumption impacts. References for the chapter are listed in Section 7.5.

a. AIR POLLUTION

i. Emission Reductions

Applying any of the control techniques discussed in Chapter 5 will reduce NO_x emissions from gas turbines. These emission reductions were estimated for the model plants presented in Table 6-1 and are shown in Table 7-1. For each model plant, the uncontrolled and controlled emissions, emission reductions, and percent reductions are presented. The following paragraphs discuss NO_x emission reductions for each control technique.

Nitrogen oxide emission reductions for water or steam injection are estimated as discussed in Section 6.1.3. The percent reduction in emissions from uncontrolled levels varies for each model plant ranging, from 60 to 96 percent. This reduction depends on each model's uncontrolled emissions, the

TABLE 7-1. MODEL PLANT UNCONTROLLED AND CONTROLLED NO_x EMISSIONS FOR AVAILABLE NO_x CONTROL TECHNIQUES

Gas turbine model	Annual operating hours	Type of wet injection	Annual emissions ^a	Uncontrolled NO _x emissions, ^a tons/yr	Controlled NO _x emissions, tons/year					SCR NH ₃ emissions @ SLIP = 10 ppm (tons/yr) ^c
					Wet injection to levels in Table 6-6	Dry low-NO _x combustor to 42 ppmv	Dry low-NO _x combustor to 25 ppm	Dry low-NO _x combustor to 9 ppmv	NO _x emissions, wet injection + SCR ^b	
Centaur T4500 3.3 MW Gas fuel	8,000	Water	Emissions, tons/yr Reduction, tons/yr Total reduction, %	88.1	28.5 59.6 68%	28.5 59.6 68%	16.9 71.2 81%	NA ^d — —	6.10 22.4 93%	2.92
501-KB5 4.0 MW Gas fuel	8,000	Water	Emissions, tons/yr Reduction, tons/yr Total reduction, %	126	34.2 91.8 73%	NA — —	NA — —	NA — —	7.32 26.9 94%	2.58
LM2500 22.7 MW Gas fuel	8,000	Water	Emissions, tons/yr Reduction, tons/yr Total reduction, %	581	140 441 76%	NA — —	NA — —	NA — —	30.0 110 95%	11.2
MS5001P 26.8 MW Gas fuel	8,000	Water	Emissions, tons/yr Reduction, tons/yr Total reduction, %	723	214 509 70%	NA — —	NA — —	NA — —	45.8 168 94%	20.4
ABB GT11N 83.3 MW Gas fuel	8,000	Water	Emissions, tons/yr Reduction, tons/yr Total reduction, %	5,410	347 5,060 94%	NA — —	347 5060 94%	125 5290 98%	125 222 98%	51.7
MS7001E 84.7 MW Gas fuel	8,000	Water	Emissions, tons/yr Reduction, tons/yr Total reduction, %	2,170	593 1580 73%	NA — —	353 1820 84%	127 2040 94%	127 466 94%	49.6
501-KB5 4.0 MW Gas fuel	8,000	Steam	Emissions, tons/yr Reduction, tons/yr Total reduction, %	126	34.2 92 73%	NA — —	NA — —	NA — —	7.32 26.9 94%	2.58
LM2500 22.7 MW Gas fuel	8,000	Steam	Emissions, tons/yr Reduction, tons/yr Total reduction, %	581	83.5 498 86%	NA — —	NA — —	NA — —	30.0 53.5 95%	11.2
MS5001P 26.8 MW Gas fuel	8,000	Steam	Emissions, tons/yr Reduction, tons/yr Total reduction, %	723	214 509 70%	NA — —	NA — —	NA — —	45.8 168 94%	20.4

TABLE 7-1. (continued)

Gas turbine model	Annual operating hours	Type of wet injection	Annual emissions ^a	Uncontrolled NO _x emissions, ^a tons/yr	Controlled NO _x emissions, tons/year					SCR NH ₃ emissions @ SLIP = 10 ppm (tons/yr) ^c
					Wet injection to levels in Table 6-6	Dry low-NO _x combustor to 42 ppmv	Dry low-NO _x combustor to 25 ppm	Dry low-NO _x combustor to 9 ppmv	NO _x emissions, wet injection + SCR ^b	
LM5000 34.4 MW Gas fuel	8,000	Steam	Emissions, tons/yr Reduction, tons/yr Total reduction, %	930	126 804 86%	NA — —	NA — —	NA — —	45.2 80.8 95%	20.5
ABB GT11N 83.3 MW Gas fuel	8,000	Steam	Emissions, tons/yr Reduction, tons/yr Total reduction, %	5,410	583 4830 89%	NA — —	347 5060 94%	125 5290 98%	125 458 98%	51.7
MS7001E 84.7 MW Gas fuel	8,000	Steam	Emissions, tons/yr Reduction, tons/yr Total reduction, %	2,170	593 1580 73%	NA — —	353 1820 84%	127 2040 94%	127 466 94%	49.6
MS7001F 161 MW Gas fuel	8,000	Steam	Emissions, tons/yr Reduction, tons/yr Total reduction, %	5,150	1,030 4120 80%	NA — —	610 4540 88%	NA — —	221 809 96%	71.7
Centaur T4500 3.3 MW Oil fuel	8,000	Water	Emissions, tons/yr Reduction, tons/yr Total reduction, %	125	41.8 83.2 67%	NA — —	NA — —	NA — —	12.5 29.3 90%	2.9
MS5001P 26.3 MW Oil fuel	8,000	Water	Emissions, tons/yr Reduction, tons/yr Total reduction, %	1,090	337 753 69%	NA — —	NA — —	NA — —	46.6 290 96%	20.4
MS7001E 83.3 MW Oil fuel	8,000	Water	Emissions, tons/yr Reduction, tons/yr Total reduction, %	3,290	938 2350 71%	NA — —	NA — —	NA — —	130 808 96%	49.6
Centaur T4500 3.3 MW Gas fuel	2,000	Water	Emissions, tons/yr Reduction, tons/yr Total reduction, %	22.0	7.1 14.9 68%	NA — —	NA — —	NA — —	1.5 6 93%	0.7
MS5001P 26.8 MW Gas fuel	2,000	Water	Emissions, tons/yr Reduction, tons/yr Total reduction, %	181	53.5 128 70%	NA — —	NA — —	NA — —	11.5 42 94%	5.1

TABLE 7-1. (continued)

Gas turbine model	Annual operating hours	Type of wet injection	Annual emissions ^a	Uncontrolled NO _x emissions, ^a tons/yr	Controlled NO _x emissions, tons/year					SCR NH ₃ emissions @ SLIP = 10 ppm (tons/yr) ^c
					Wet injection to levels in Table 6-6	Dry low-NO _x combustor to 42 ppmv	Dry low-NO _x combustor to 25 ppm	Dry low-NO _x combustor to 9 ppmv	NO _x emissions, wet injection + SCR ^b	
MS7001E 84.7 MW Gas fuel	2,000	Water	Emissions, tons/yr Reduction, tons/yr Total reduction, %	543	148 395 73%	NA — —	88 455 84%	32 511 94%	31.8 116 94%	12.4
Centaur T4500 3.3 MW Oil fuel	2,000	Water	Emissions, tons/yr Reduction, tons/yr Total reduction, %	31.2	10.0 21.2 68%	NA — —	NA — —	NA — —	3.14 6.9 90%	0.7
MS5001P 26.8 MW Oil fuel	2,000	Water	Emissions, tons/yr Reduction, tons/yr Total reduction, %	273	84 189 69%	NA — —	NA — —	NA — —	23.3 61 91%	5.1
MS7001E 84.7 MW Oil fuel	2,000	Water	Emissions, tons/yr Reduction, tons/yr Total reduction, %	822	234 588 72%	NA — —	NA — —	NA — —	64.9 169 92%	12.4
SATURN T1500 1.1 MW Oil fuel	1,000	Water	Emissions, tons/yr Reduction, tons/yr Total reduction, %	5.00	1.99 3 60%	NA — —	NA — —	NA — —	0.30 1.7 94%	0.13
TPM FT4 28.0 MW Oil fuel	1,000	Water-in-oil emulsion	Emissions, tons/yr Reduction, tons/yr Total reduction, %	977	37.3 940 96%	NA — —	NA — —	NA — —	6.72 30.6 99%	NC ^e — —

^aUncontrolled and controlled NO_x emissions are from cost-effectiveness tables in Chapter 6.

^bControlled NO_x emission level for wet injection plus SCR is 9 ppmv for natural gas fuel and 18 ppmv for distillate oil fuel.

^cAmmonia emissions, in tons per year = (SLIP, ppmv) x (MM/1,000,000) x (GT exhaust, lb/sec) x (MW NH₃ = 15/MW exhaust = 28.6) x (3,600 sec/hr) x (ton/2,000 lb) x (annual operating hrs).

^dNA-control technology not available for this model plant.

^eNC-data not available to calculate emissions for this control scenario.

water-to-fuel ratio (WFR), and type of fuel and whether water or steam is injected.

Achievable emission levels from gas turbines using dry low- NO_x combustors were obtained from manufacturers. Controlled NO_x levels of 42, 25, and 9 parts per million, by volume (ppmv), referenced to 15 percent oxygen, were reported by the various turbine manufacturers, and each of these levels is shown in Table 7-1, where applicable, for each model plant. The percent reduction in NO_x emissions from uncontrolled levels for gas turbines using these combustors ranges from 68 to 98 percent. Virtually all SCR units installed in the United States are used in combination with either wet controls or combustion controls. For this analysis, emission reductions were calculated for SCR in combination with water or steam injection. Using the turbine manufacturers' guaranteed NO_x emissions figures for wet injection and a controlled NO_x emission level of 9 ppmv, referenced to 15 percent oxygen, exiting the SCR, the percent reduction in NO_x emissions for this combination of control techniques ranges from 93 to 99 percent.

Estimated ammonia (NH_3) emissions, in tons per year, corresponding to ammonia slip from the SCR system are also shown in Table 7-1. These estimates are based on an ammonia slip level of 10 ppmv, consistent with information and data presented in Section 5.4. For continuous-duty model plants, the annual NH_3 emissions range from approximately 3 tons for a 3.3 megawatt (MW) (4,425 horsepower [hp]) model plant to 72 tons for a 160 MW (215,000 hp) model plant.

ii. Emissions Trade-Offs

The formation of both thermal and fuel NO_x depends upon combustion conditions. Water/steam injection, lean combustion, and reduced residence time modify combustion conditions to reduce the amount of NO_x formed. These combustion modifications may increase carbon monoxide (CO) and unburned hydrocarbon (HC) emissions. Using SCR to control NO_x emissions produces ammonia emissions. The impacts of these NO_x controls on CO, HC, and ammonia emissions are discussed below.

(1) Impacts of Wet Controls on CO and HC Emissions. As discussed in Section 5.1.5, wet injection may increase CO and HC emissions. Injecting water or steam into the flame area of a turbine combustor lowers the flame temperature and thereby reduces NO_x emissions. This reduction in temperature to some extent inhibits complete combustion, resulting in increased CO and HC emissions. Figure 5-12 shows the impact of water and steam injection on CO emissions for production gas turbines.² The impact of steam injection on CO emissions is less than that of water injection. As seen in Figure 5-12, CO emissions increase with increasing WFR's. Wet injection increases HC emissions to a lesser extent than it increases CO emissions. Figure 5-13 shows the impact of water injection on HC emissions for one turbine. In cases where water and steam injection result in excessive CO and HC emissions, an oxidation catalyst (add-on control) can be installed to reduce these emissions by converting the CO and HC to water (H₂O) and carbon dioxide (CO₂).

(2) Impacts of Combustion Controls on CO and HC Emissions. As discussed in Section 5.2.1, the performance of lean combustion in limiting NO_x emissions relies in part on reduced equivalence ratios. As the equivalence ratio is reduced below the stoichiometric level of 1.0, combustion flame temperatures drop, and as a result NO_x emissions are reduced. Shortening the residence time in the high-temperature flame zone also will reduce the amount of thermal NO_x formed. These lower equivalence ratios and/or reduced residence time, however, may result in incomplete combustion, which may increase CO and HC emissions. The extent of the increase in CO and HC emissions is specific to each turbine manufacturer's combustor designs and therefore varies for each turbine model. As with wet injection, if necessary, an oxidation catalyst can be installed to reduce excessive CO and HC emissions by converting the CO and HC to CO₂ and H₂O.

(3) Ammonia Emissions from SCR. The SCR process reduces NO_x emissions by injecting NH₃ into the flue gas. The NH₃ reacts with NO_x in the presence of a catalyst to form H₂O and nitrogen

(N₂). The NO_x removal efficiency of this process is partially dependent on the NH₃/NO_x ratio. Increasing this ratio reduces NO_x emissions but increases the probability that unreacted ammonia will pass through the catalyst unit into the atmosphere (known as ammonia "slip"). Some ammonia slip is unavoidable because of ammonia injection control limitations and imperfect distribution of the reacting gases. A properly designed SCR system will limit ammonia slip to less than 10 ppmv (see Section 5.4).

b. SOLID WASTE DISPOSAL

Catalytic materials used in SCR units for gas turbines include precious metals (e.g., platinum), zeolites, and heavy metal oxides (e.g., vanadium, titanium). Vanadium pentoxide, the most commonly used SCR catalyst in the United States, is identified as an acute hazardous waste under RCRA Part 261, Subpart D - Lists of Hazardous Wastes. The Best Demonstrated Available Technology (BDAT) Treatment Standards for Vanadium P119 and P120 states that spent catalysts containing vanadium pentoxide are not classified as hazardous waste.¹ State and local regulatory agencies, however, are authorized to establish their own hazardous waste classification criteria, and spent catalysts containing vanadium pentoxide may be classified as a hazardous waste in some areas. Although the actual amount of vanadium pentoxide contained in the catalyst bed is small, the volume of the catalyst unit containing this material is quite large and disposal can be costly. Where classified by State or local agencies as a hazardous waste, this waste may be subject to the Land Disposal Restrictions in 40 CFR Part 268, which allows land disposal only if the hazardous waste is treated in accordance with Subpart D - Treatment Standards. Such disposal problems are not encountered with other catalyst materials, such as precious metals and zeolites, because these materials are not hazardous wastes.

c. WATER USAGE AND WASTE WATER DISPOSAL

Water availability and waste water disposal are environmental factors to be considered with wet injection. The impact of water usage on the water supply at some remote sites,

in small communities, or in areas where water resources may be limited is an environmental factor that should be examined when considering wet injection. The volume of water required for wet injection is shown in Table 7-2

TABLE 7-2. WATER AND ELECTRICITY CONSUMPTION FOR NO_x CONTROL TECHNIQUES

Gas turbine model ^a	Turbine power output, MW	Annual operating hours	Fuel type	Type of emission control	Total water flow, gal/min ^a	Waste water flow, gal/min ^b	Water pump power, kW ^c	Wet injection power consumption, kW-hr/yr ^d	SCR power penalty, kW-hr/yr ^e
Centaur T4500	3.3	8,000	Gas	Water inj.	2.5	0.73	0.40	3,220	132,000
501-KB5	4.0	8,000	Gas	Water inj.	3.94	1.14	0.63	5,070	160,000
LM2500	22.7	8,000	Gas	Water inj.	14.8	4.29	2.38	19,100	908,000
MS5001P	26.8	8,000	Gas	Water inj.	22.2	6.44	3.57	28,600	1,070,000
ABB GT11N	83.3	8,000	Gas	Water inj.	154	44.7	24.8	198,000	3,330,000
MS7001E	84.7	8,000	Gas	Water inj.	69.2	20.1	11.1	89,100	3,390,000
501-KB5	4.0	8,000	Gas	Steam inj.	7.38	2.14	1.19	9,510	160,000
LM2500	22.7	8,000	Gas	Steam inj.	29.5	8.56	4.75	38,000	908,000
MS5001P	26.8	8,000	Gas	Steam inj.	33.3	9.66	5.36	42,900	1,070,000
LM5000	34.4	8,000	Gas	Steam inj.	50.8	14.7	8.18	65,400	1,380,000
ABB GT11N	83.3	8,000	Gas	Steam inj.	178	51.6	28.7	229,000	3,330,000
MS7001E	84.7	8,000	Gas	Steam inj.	104	30.2	16.7	134,000	3,390,000
MS7001F	161	8,000	Gas	Steam inj.	199	57.7	32.0	256,000	6,440,000
Centaur T4500	3.3	8,000	Oil	Water inj.	2.76	0.80	0.44	3,550	132,000
MS5001P	26.3	8,000	Oil	Water inj.	26.7	7.74	4.30	34,400	1,050,000
MS7001E	83.3	8,000	Oil	Water inj.	63.8	18.5	10.3	82,200	833,000
Centaur T4500	3.3	2,000	Gas	Water inj.	2.50	0.73	0.40	3,220	33,000
MS5001P	26.3	2,000	Gas	Water inj.	22.2	6.44	3.57	28,600	263,000
MS7001E	84.7	2,000	Gas	Water inj.	69.2	20.1	11.1	89,100	847,000
Centaur T4500	3.3	2,000	Oil	Water inj.	2.76	0.80	0.44	3,550	33,000
MS5001P	26.3	2,000	Oil	Water inj.	26.7	7.74	4.30	34,400	263,000
MS7001E	84.7	2,000	Oil	Water inj.	63.8	18.5	10.3	82,200	847,000
SATURN T1500	1.1	1,000	Oil	Water inj.	0.81	0.23	0.13	1,040	5,500
TPM FT4	28.0	1,000	Oil	Water-in-oil emulsion	21.7	6.29	3.49	27,900	140,000

^aFrom Table 6-2.

^bCalculated as 29 percent of the total water flow.

^cPower requirement for water pump is calculated as shown in Section 6.1.2.2.

for each model plant.

Water 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. Water treatment systems are used to achieve water quality specifications set by gas turbine manufacturers. Table 5-4 summarizes these specifications for six manufacturers.

Discharges from these water treatment systems have a potential impact on water quality. As indicated in Section 6.1, approximately 29 percent of the treated water flow rate (22.5 percent of the raw water flow rate) is considered to be discharged as wastewater. The wastewater flow rates for each of the model plants with a water or steam injection control system are estimated using this factor, and the results are presented in Table 7-2. The wastewater contains increased levels of those pollutants in the raw water (e.g., calcium, silica, sulfur, as listed in Table 5-4) that are removed by the water treatment system, along with any chemicals introduced by the treatment process. Based on a wastewater flowrate equal to 29 percent of the influent raw water, the concentration of pollutants discharged from the water treatment system is approximately three times higher than the pollutant concentrations in the raw water.

The impacts of these pollutants on water quality are site-specific and depend on the type of water supply and on the discharge restrictions. Influent water obtained from a municipality will not contain high concentrations of pollutants. However, surface water or well water used at a remote site might contain high pollutant concentrations and may require additional pretreatment to meet the water quality specifications set by

manufacturers. This additional pretreatment will increase the pollutant concentrations of the wastewater discharge. Wastewater discharges to publicly-owned treatment works (POTW's) must meet the requirements of applicable Approved POTW Pretreatment Programs.

d. ENERGY CONSUMPTION

Additional fuel and electrical energy is required over baseline for wet injection controls, while additional electrical energy is required for SCR controls. The following paragraphs discuss these energy consumption impacts.

Injecting water or steam into the turbine combustor lowers the net cycle efficiency and increases the power output of the turbine. The thermodynamic efficiency of the combustion process is reduced because energy that could otherwise be available to perform work in the turbine must now be used to heat the water/steam. This lower efficiency is seen as an increase in fuel use. Table 5-10 shows the impacts of wet injection on gas turbine performance for one manufacturer. This table shows a 2 to 4 percent loss in efficiency associated with WFR's required to achieve NO_x emission levels of 25 to 42 ppmv in gas turbines burning natural gas. The actual efficiency loss is specific to each turbine model but generally increases with increasing WFR's and is higher for water injection than for steam injection (additional energy is required to heat and vaporize the water). One exception to this efficiency penalty occurs with steam injection, in which exhaust heat from the gas turbine is used to generate the steam for injection. If the heat recovered in generating the steam would otherwise be exhausted to atmosphere, the result is an increase in net cycle efficiency.

The energy from the increased mass flow and heat capacity of the injected water/steam can be recovered in the turbine, resulting in an increase in power output accompanying the reduced efficiency of the turbine (shown in Table 5-10 for one manufacturer). This increase in power output can be significant and could lessen the impact of the loss in efficiency if the facility has a demand for the available excess power.

Water and steam injection controls also require additional electrical energy to operate the water injection feed water pumps. The annual electricity usage for each model is the product of the pump power demand, discussed in Section 6.1.2.2, and the annual hours of operation. Table 7-2 summarizes this electricity usage for each of the model plants.

For SCR units, additional electrical energy is required to operate ammonia pumps and ventilation fans. This energy requirement, however, is believed to be small and was not included in this analysis.

The increased back-pressure in the turbine exhaust system resulting from adding an SCR system reduces the power output from the turbine. As discussed in Section 6.3.2.9, the power output is typically reduced by approximately 0.5 percent. This power penalty has been calculated for each model plant and is shown in Table 7-2.

e. REFERENCE FOR CHAPTER 7

1.. 55 FR 22276, June 1, 1990.

APPENDIX A

Exhaust NO_x emission levels were provided by gas turbine manufacturers in units of parts per million, by volume (ppmv), on a dry basis and corrected to 15 percent oxygen. A method of converting these exhaust concentration levels to a mass flow rate of pounds of NO_x per hour (lb NO_x/hr) was provided by one gas turbine manufacturer.¹ This method uses an emission index (EINO_x), in units of lb NO_x/1,000 lb fuel, which is proportional to the exhaust NO_x emission levels in ppmv by a constant, K. The relationship between EINO_x and ppmv for NO_x emissions is stated in Equation 1 below and applies for complete combustion of a hydrocarbon fuel and combustion air having no CO₂ and an O₂ mole percent of 20.95:

$$\frac{\text{NO}_x \text{ Ref. } 15\% \text{ O}_2}{\text{EINO}_x} = K \quad \text{Equation 1}$$

where: NO_x Ref. 15% O₂
 = NO_x, ppmvd @15% O₂ (provided by gas

turbine manufacturers);
 EINO_x

= NO_x emission index, lb NO_x/1,000 lb

fuel; and
 K

= constant, based on the molar

hydrocarbon

ratio of the fuel.

The derivation of Equation 1 was provided by the turbine manufacturer and is based on basic thermodynamic laws and supported by test data provided by the manufacturer. According to the manufacturer, this equation can be used to estimate NO_x emissions for operation with or without water/steam injection.

Equation 1 shows that NO_x emissions are dependent only upon the molar hydrocarbon ratio of the fuel and are independent of the air/fuel ratio (A/F). The equation therefore is valid for all gas turbine designs for a given fuel. The validity of this approach to calculate NO_x emissions was supported by a second

turbine manufacturer.² Values for K were provided for several fuels and are given below:^{1,2}

Pipeline quality natural gas:

K = 12.1

Distillate fuel oil No. 1 (DF-1):

K = 13.1

Distillate fuel oil No. 2 (DF-2):

K = 13.2

Jet propellant No. 4 (JP-4):

K = 13.0

Jet propellant No. 5 (JP-5):

K = 13.1

Methane:

K = 11.6

The following examples are provided for calculating NO_x emissions on a mass basis, given the fuel type and NO_x emission level, in ppmv, dry (ppmvd), and corrected to 15 percent O₂.

Example 1. Natural gas fuel

Gas turbine:

Solar Centaur 'H'

Power output:

4,040 kW

Heat rate:

12,200 Btu/kW-hr

NO_x emissions:

105 ppmvd, corrected to 15 percent O₂

Fuel:

Natural gas

- lower heating value = 20,610 Btu/lb

- K = 12.1

Fuel flow:

$$4,040 \text{ kW} \times \frac{12,200 \text{ Btu}}{\text{kW-hr}} \times \frac{1 \text{ lb fuel}}{20,610 \text{ Btu}} = 2,391 \text{ lb/hr}$$

From Equation 1:

$$\frac{105}{E \text{INO}_x} = 12.1$$

NO_x emissions, lb/hr:

$$2,391 \frac{\text{lb fuel}}{\text{hr}} \times \frac{8.68 \text{ lb NO}_x}{1,000 \text{ lb fuel}} = 20.8 \frac{\text{lb NO}_x}{\text{hr}}$$

Example 2. Distillate oil fuel

Gas turbine:

General Electric LM2500

Power output:

22670 kW

Heat rate:

9296 Btu/kW-hr

NO_x emissions: 345 ppmvd, corrected to 15 percent O₂

Fuel:

Distillate oil No. 2

-

lower heating value = 18,330 Btu/lb

- K = 13.2

Fuel flow:

$$22,670 \text{ kW} \times 9296 \frac{\text{Btu}}{\text{kW-hr}} \times \frac{1 \text{ lb fuel}}{18,330 \text{ Btu}} = 11,500 \text{ lb/hr}$$

From Equation 1:

$$\frac{345}{\text{EINO}_x} = 13.2$$

NO_x emissions, lb/hr:

$$11,500 \frac{\text{lb fuel}}{\text{hr}} \times \frac{26.1 \text{ lb NO}_x}{1,000 \text{ lb fuel}} = 300 \frac{\text{lb NO}_x}{\text{hr}}$$

REFERENCES FOR APPENDIX A:

1. Letter and attachments from Lyon, T.F., General Electric Aircraft Engines, to Snyder, R.B., MRI. December 6, 1991. Calculation of NO_x emissions from gas turbines.
2. Letter and attachments from Hung, W.S., Solar Turbines, Inc., to Snyder, R.B., MRI. December 17, 1991. Calculation of NO_x emissions from gas turbines.

**APPENDIX B. COST DATA AND METHODOLOGY USED TO PREPARE COST
FIGURES PRESENTED IN CHAPTER 6**

APPENDIX B. RAW COST DATA AND COST ALGORITHMS

The maintenance costs for water injection and several of the SCR costs presented in Chapter 5 are based on information from turbine manufacturers and other sources that required interpretation and analysis. Information about additional gas turbine maintenance costs associated with water injection is presented in Section B.1. Information on SCR capital costs, catalyst replacement and disposal costs, and maintenance costs is presented in Section B.2. References are listed in Section B.3.

B.1 WATER INJECTION MAINTENANCE COSTS

Information from each manufacturer and the applicable analysis procedures used to develop maintenance cost impacts for water injection are described in the following sections.

B.1.1 Solar

This manufacturer indicated that the annual maintenance cost for the Centaur is \$16,000/year.¹ The cost for the Saturn was estimated to be \$8,000.² This \$8,000 cost was then prorated for operation at 1,000/hr/yr, and was multiplied by 1.3 to account for the additional maintenance required for oil fuel.

B.1.2 Allison

Maintenance costs for water injection were provided by a company that packages Allison gas turbines for stationary applications. This packager stated that for the 501 gas turbine model, a maintenance contract is available which covers all maintenance materials and labor costs associated with the turbine, including all scheduled and unscheduled activities. The cost of this contract for the 501 model is \$0.0005 to \$0.0010 per KW-hour (KWH) more for water injection than for a turbine not using water injection.³ For an installation operating 8,000 hours per year at a base-rated output of 4,000 KW, and using an average cost of \$0.00075 per KWH, the annual additional maintenance cost is \$24,000. By the nature of the contract offered, this figure represents a worst case scenario and to some extent may exceed the actual incremental maintenance costs that would be expected for water injection for this turbine.

B.1.3 General Electric

General Electric (GE) offers both aero-derivative type (LM-series models) and heavy-duty type (MS-series models) gas turbines. For the aero-derivative turbines, GE states that the incremental maintenance cost associated with water injection is \$3.50 per fired hour. This cost is used to calculate the maintenance cost for water injection for GE aeroderivative turbines. No figures were provided for steam injection and no maintenance cost was used for steam injection with these turbines.⁴

Water injection also impacts the maintenance costs for the heavy-duty MS-series models. Costs associated with more frequent maintenance intervals required for models using water injection have been calculated and summarized below. A GE representative stated that the primary components which must be repaired at each maintenance interval are the combustor liner and transition pieces.⁵ Approximate costs to repair these pieces were provided by GE.⁵ For this analysis, the maximum cost estimates were used to calculate annual costs to accommodate repairs that may be required periodically for injection nozzles, cross-fire tubes, and other miscellaneous hardware. According to GE, a rule of thumb is that if the repair cost exceeds 60 percent of the cost of a new part, the part is replaced.⁵ The cost of a replacement part is therefore considered to be 1.67 times the maximum repair cost. If water purity requirements are met, there are no significant adverse impacts on maintenance requirements on other turbine components, and hot gas path inspections and major inspection schedules are not impacted.⁵ Combustion repair schedules, material costs, and labor hours are shown in Table B-1. Scheduled maintenance intervals for models with water injection were provided in Reference 6. Corresponding maintenance intervals for models with steam injection were assumed to be the same as models with no wet injection; these scheduled maintenance intervals were provided in Reference 7. Using the information in Table B-1, the total annual cost is

calculated and shown in Table B-2 for three GE heavy-duty turbine models.

B.1.4 Asea Brown Boveri

This manufacturer states there are no maintenance impacts associated with water injection.⁸

B.2 SCR COSTS

The total capital investment, catalyst replacement, and maintenance costs are estimated based on information from the technical literature. The cost algorithms are described in the following sections.

B.2.1 Total Capital Investment

Total capital investment costs, which include purchased costs and installation costs, were available for SCR systems for combined cycle and cogeneration applications from five sources.⁹⁻¹³ These costs were scaled to 1990 costs using the Chemical Engineering annual plant cost indexes and are applicable to SCR systems in which the catalyst was placed within the heat recovery steam generator (HRSG). In addition, estimated capital investment costs were available from one source for SCR systems in which a high temperature zeolite catalyst is installed upstream of the HRSG.¹⁴ Both the original data and the scaled costs are presented in Table B-3. The scaled costs were plotted against the turbine size and this plot is shown in Figure B-1. A linear regression analysis was performed to determine the equation for the line that best fits the data. This equation was used to estimate the total capital investment for SCR for the model plants and was extrapolated to estimate the costs for model plants larger than 90 MW.

B.2.2 Maintenance Costs

Maintenance costs for SCR controls were obtained from four literature sources, although 6 of the 14 points were obtained from one article.^{9,11-13} These costs were scaled to 1990 costs assuming an inflation rate of five percent per year. All of the data are for turbines that use natural gas fuel. Because there are no data to quantify differences in SCR maintenance costs for oil-fired applications, the available data for operation on

natural gas were used for both fuels. Both the original data and the scaled costs are presented in Table B-4. The scaled costs were plotted versus the turbine size in Figure B-2. The equation for the line through the data was determined by linear regression, and it was used to estimate the maintenance costs for the model plants.

B.2.3 Catalyst Replacement Costs

Catalyst replacement costs were obtained from three articles for nine gas turbine installations.^{9,11,13} Combined catalyst replacement and disposal costs were obtained for another six gas turbine installations from one article.¹² The disposal costs for these six gas turbine installations were estimated based on estimated catalyst volumes and a unit disposal cost of \$15/ft³, given in Reference 15.

The catalyst volumes were estimated assuming there is a direct relationship between the volume and the turbine size; the catalyst volume stated in Reference 16 for one 83 MW turbine is 175 m³. The resulting disposal costs for these six facilities were subtracted from the combined replacement and disposal costs to estimate the replacement-only costs. All of the replacement costs were scaled to 1990 costs assuming an inflation rate of 5 percent per year. The original data and the scaled costs are presented in Table B-5, and the scaled replacement costs were also plotted versus the turbine size in Figure B-3. Linear regression was used to determine the equation for the line through the data. This equation was used to estimate the catalyst replacement costs for the model plants.

Total Capital Investment SCR Control for Gas Turbines

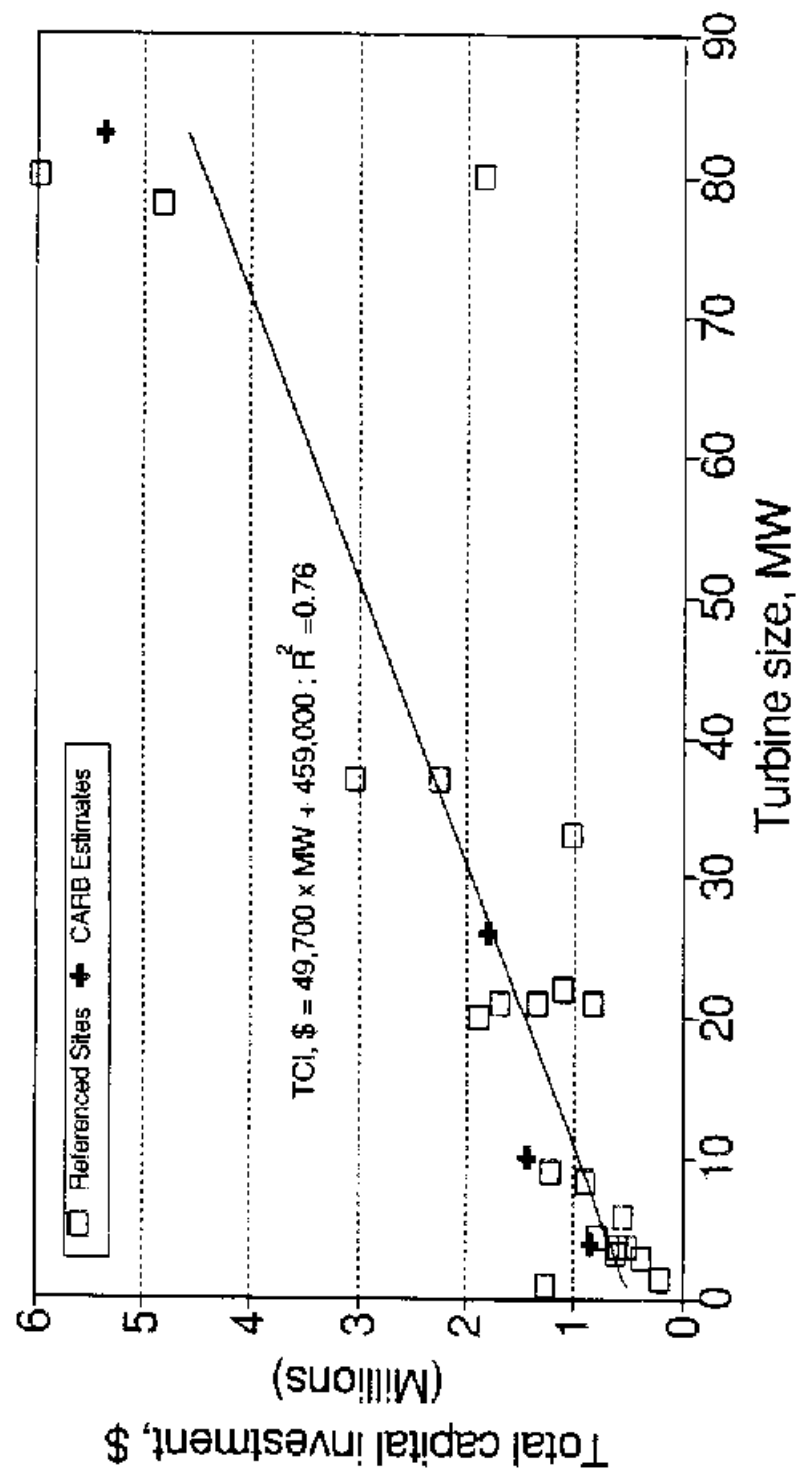


Figure B-1. Total Capital Investment for SCR Control of NO_x Emissions from Gas Turbines

Annual Maintenance Cost SCR Control for Gas Turbines

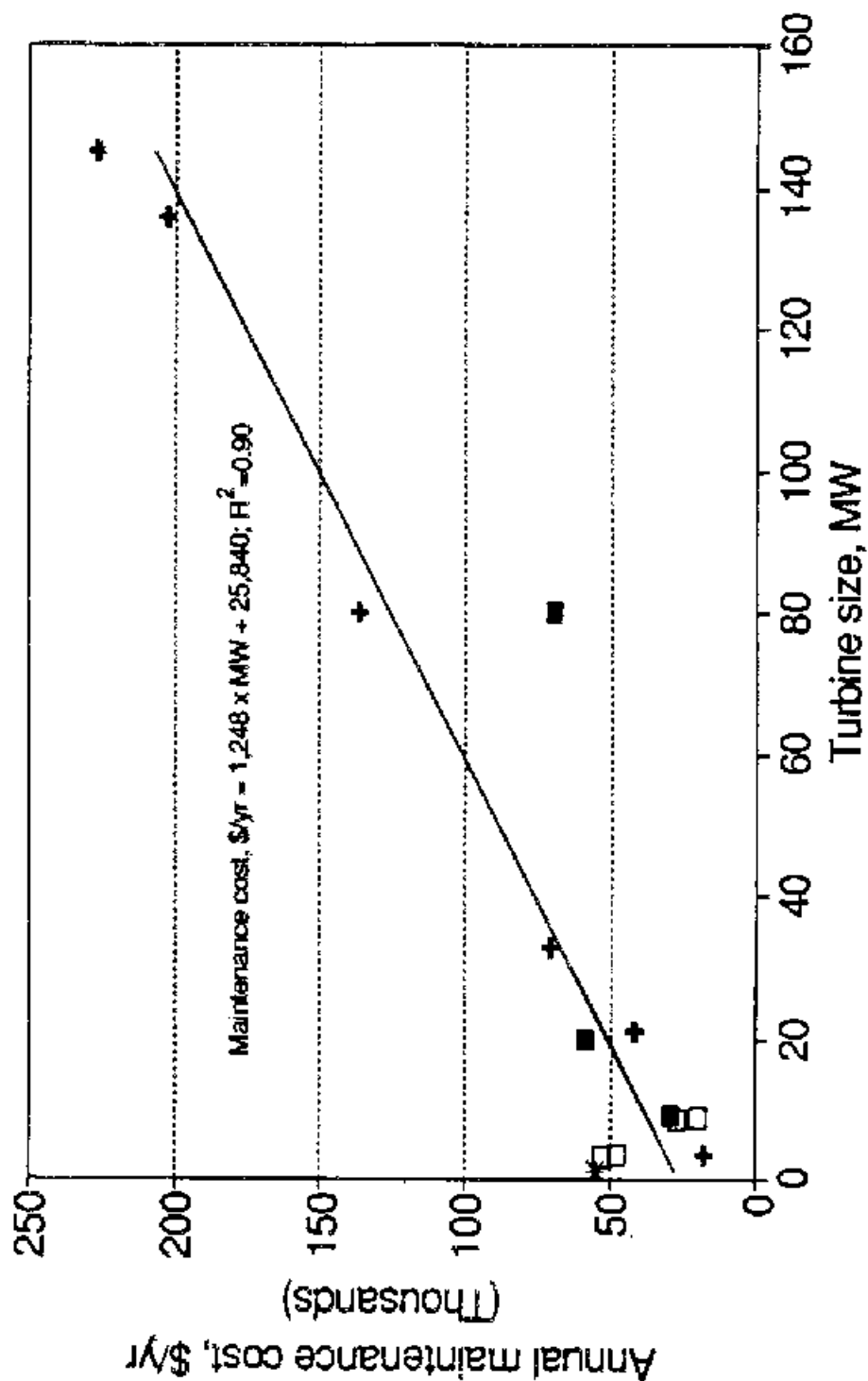


Figure B-2. Annual Maintenance Cost for SCR Control of NO_x Emissions from Gas Turbines

Catalyst Replacement Annual Cost SCR Control for Gas Turbines

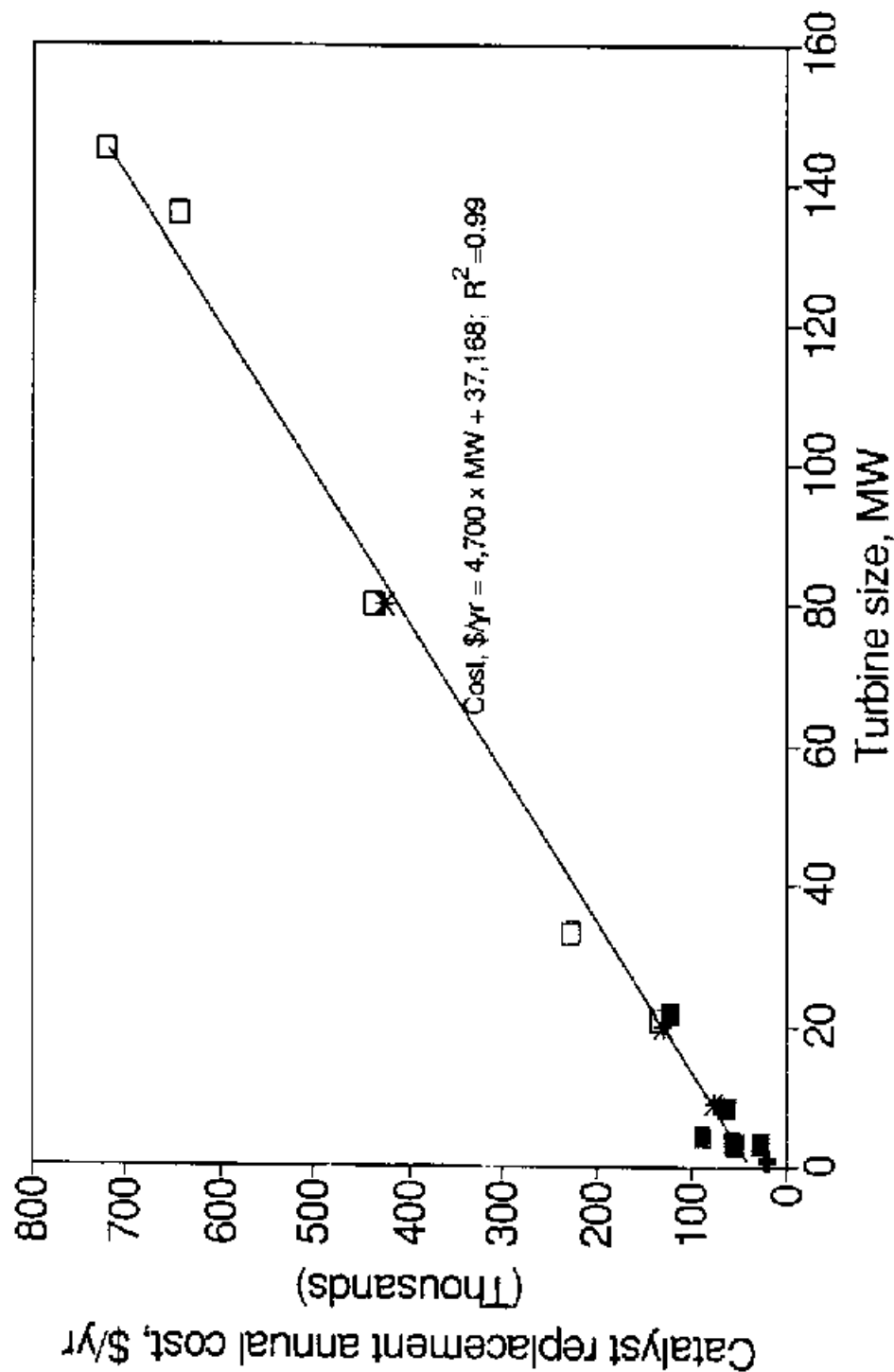


Figure B-3. Catalyst Replacement Annual Cost for SCR Control of Gas Turbines

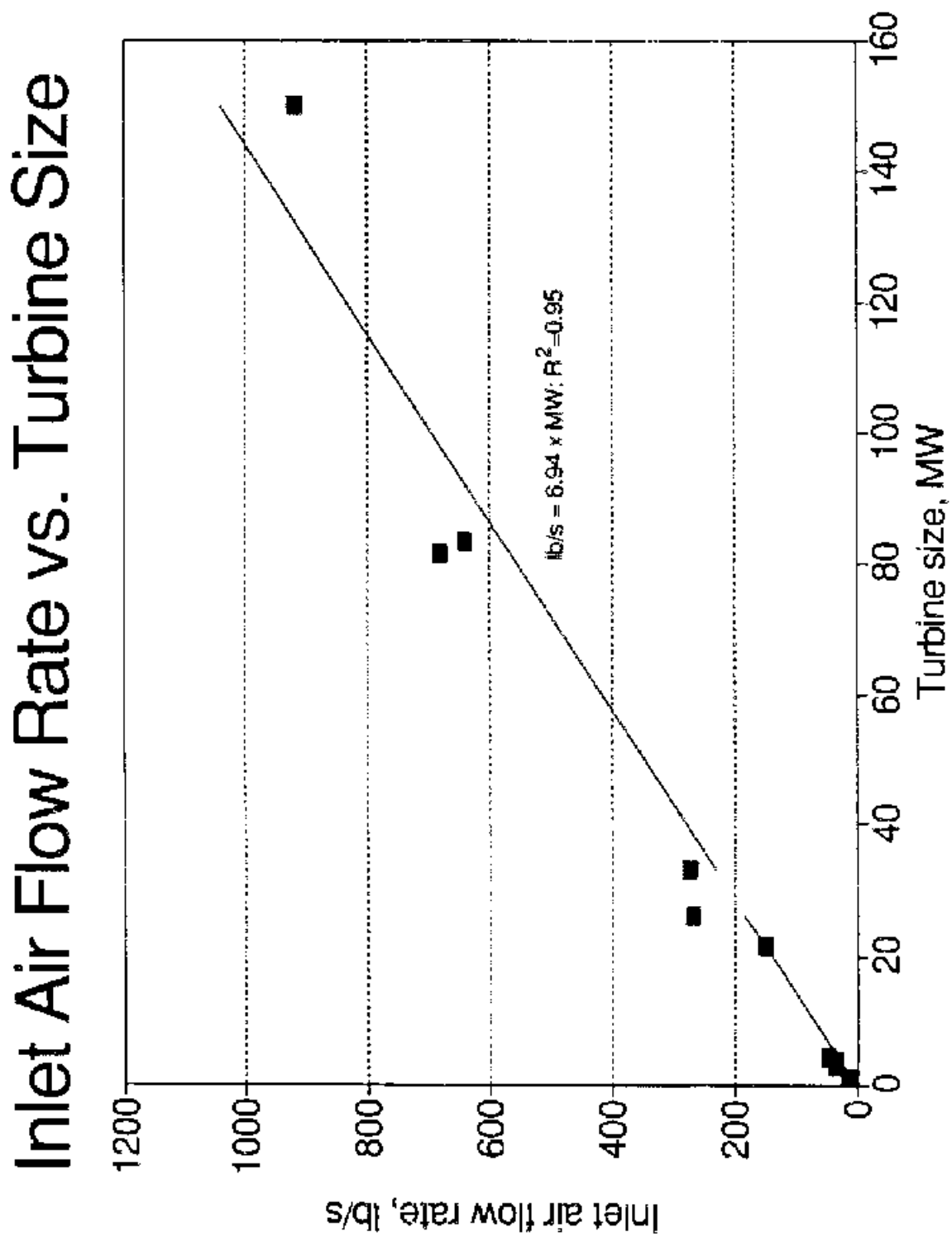


Figure B-4. Inlet Air Flow Rate for Gas Turbines

TABLE B-1. COMBUSTOR REPAIR INTERVALS, HOURS, AND MATERIAL COST

	Repair interval, hr		Replacement interval, hr		Repair cost, \$ ^d	Replacement cost, \$ ^d	Item	Labor hours
	Dry	^a Wet ^b	Dry ^a	Wet ^c				
Gas turbine								
MS5001P	12,000	6,000	48,000	24,000	10,000-15,000 15,000-20,000	25,000 42,000	Liners Transition pieces	160
MS7001E	8,000	6,500	48,000	39,000	15,000-30,000 30,000-50,000	50,000 83,000	Liners Transition pieces	576
MS9001E	8,000	6,500	48,000	39,000	31,000-62,000 62,000-124,000	103,000 206,000	Liners Transition pieces	624

^aReference 7.

^bReference 6.

^cScaled from Dry Repair/Replace intervals found in Reference 9.

^dReference 5.

TABLE B-2. ANNUAL COST OF ADDITIONAL MAINTENANCE REQUIRED FOR WATER INJECTION

	Number of inspections over 15 years										Material costs	Labor, each inspection		Total added cost 15 years	Total added annual cost
	Dry		Wet		Added number for wet		Replacement		Inspection	Replacement		Hours	Cost		
	Inspection	Replacement	Inspection	Replacement	Inspection	Replacement									
GT Model															
MS5001P ^a															
Combustor liners	8	2	15	5	7	3			15,000	25,000				18,000	
Transition pieces	8	2	15	5	7	3			20,000	42,000	160	4,998		315,980	
MS7001E ^e														495,980	
Combustor liners	12	3	15	3.5	3	0.5			30,000	50,000				115,000	
Transition pieces	13	2	15.5	3	2.5	1			50,000	83,000	576	17,994		270,979	
MS9001E ^e														385,979	
Combustor liners	12	3	15	3.5	3	0.5			62,000	103,000				237,500	
Transition pieces	13	2	15.5	3	2.5	1			124,000	206,000	624	19,494		584,229	
														821,729	54,782

^aBased on \$31.24/hr. Since parts are normally removed and a spare set is installed at each inspection, the labor cost would be the same for either repair or replacement interval.

^bSchedule assumes liners and transition pieces are replaced every fourth inspection interval.

^c(7 x \$15,000) + (3 x \$25,000) = \$180,000.

^d(7 x \$20,000) + (3 x \$42,000) + (\$4,998 x 10) = \$315,980.

^eSchedule assumes liners are replaced every fifth interval and transition pieces every sixth interval.

TABLE B-3. TOTAL CAPITAL INVESTMENT FOR SCR TO CONTROL NO_x EMISSIONS FROM GAS TURBINES

Gas turbine size, MW	SCR capital cost ^a			Scaling factor ^c	1990 SCR capital cost, \$
	\$	Year	Ref ^b		
1.1	1,250,000	1989	9	357.6/355.4	1,260,000
1.5	180,000	1986	10	357.6/318.4	202,000
3	320,000	1986	10	357.6/318.4	359,000
3.2	600,000	1989	11	357.6/3.554	604,000
3.7	477,000	1988	12	357.6/342.5	498,000
3.7	579,000	1989	11	357.6/355.4	583,000
4	839,000	1991	14	1.0	839,000
4.5	750,000	1988	11	357.6/342.5	783,000
6	480,000	1986	10	357.6/318.4	539,000
8.4	800,000	1986	11	357.6/318.4	898,000
9	1,100,000	1987	13	357.6/323.8	1,210,000
10	1,431,000	1991	14	1.0	1,431,000
20	1,700,000	1987	13	357.6/323.8	1,880,000
21	798,000	1988	12	357.6/342.5	833,000
21	1,500,000	1986	10	357.6/318.4	1,680,000
21	1,200,000	1986	10	357.6/318.4	1,350,000
22	1,000,000	1987	11	357.6/323.8	1,100,000
26	1,800,000	1991	14	1.0	1,800,000
33	990,000	1988	12	357.6/342.5	1,030,000
37	2,000,000	1986	11	357.6/318.4	2,250,000
37	2,700,000	1986	10	357.6/318.4	3,030,000
78	4,300,000	1986	10	357.6/318.4	4,830,000
80	5,400,000	1987	13	357.6/323.8	5,960,000
80	1,760,000	1988	12	357.6/342.5	1,840,000
83	5,360,000	1991	14	1.0	5,360,000

continued

TABLE B-3. (Continued)

^aTotal capital costs were provided by several sources, but it is not clear that they are on the same basis. For example, it is likely that the type of catalyst varies and the target NO_x reduction efficiency may also vary. In addition, some estimates may not include costs for emission monitors; auxiliary equipment like the ammonia storage, handling, and transfer system; taxes and freight; or installation.

^bReference 12 also provided costs for SCR used with 136 MW and 145 MW turbines. All of the costs for this reference are lower than the costs from other sources, and the differential increases as the turbine size increases. Because there are no costs from other sources for such large turbines, these two data points would exert undue influence on the analysis; therefore, they have been excluded. Costs for large model plants were estimated by extrapolating with the equation determined by linear regression through the data for turbines with capacities less than 90 MW (see Figure B-1).

^cCosts for years prior to 1990 are adjusted to 1990 dollars based on the annual CE plant cost indexes. Costs estimated in 1991 dollars were not adjusted.

TABLE B-4. MAINTENANCE COSTS FOR SCR

Gas turbine size, MW	SCR maintenance cost ^a			Scaling factor ^b	1990 SCR maintenance cost, \$
	\$/yr	Year	Ref		
1.1	52,200	1989	9	1.050	54,800
3.2	50,000	1989	11	1.050	52,500
3.7	43,000	1988	11	1.103	47,400
3.7	15,500	1988	12	1.103	17,100
8.4	22,000	1986	11	1.216	26,700
8.9	18,000	1988	11	1.103	19,800
9	25,000	1987	13	1.158	28,900
20	50,000	1987	13	1.158	57,900
21	37,900	1988	12	1.103	41,800
33	63,700	1988	12	1.103	70,200
80	124,000	1988	12	1.103	137,000
80	60,000	1987	13	1.158	69,500
136	184,000	1988	12	1.103	203,000
145	205,000	1988	12	1.103	226,000

^aAll of the maintenance costs are for turbines that are fired with natural gas. Although sulfur in diesel fuel can cause maintenance problems, there are no data to quantify the impact. Therefore, the maintenance costs presented in this table were used for both natural gas and diesel fuel applications.

^bScaling factors are based on an estimated inflation rate of 5 percent per year.

TABLE B-5. CATALYST REPLACEMENT AND DISPOSAL COSTS

Gas turbine size, MW	Catalyst replacement cost ^a						Catalyst disposal cost			Catalyst replacement and disposal annual cost, \$/yr
	\$	Year	Ref.	Scaling factor ^b	1990 catalyst cost, \$	Annual cost, \$/yr ^c	Catalyst volume, m ³	1990 cost, \$ ^e	Annual cost, \$/yr ^c	
1.1	74,600	1989	9	1.050	78,300	20,700	2.32	1,230	324	21,000
3.2	200,000	1989	11	1.050	210,000	55,400	6.75	3,570	940	56,300
3.7		1988	12	1.103	215,000	56,600	7.80	4,130	1,090	57,700
3.7	100,000	1988	11	1.103	110,000	29,000	7.80	4,130	1,090	30,100
4.5	300,000	1988	11	1.103	331,000	87,300	9.49	5,030	1,330	89,000
8.4	200,000	1986	11	1.216	243,000	64,100	17.7	9,380	2,470	67,000
9	255,000	1987	13	1.158	295,000	77,800	19.0	10,100	2,660	80,000
20	434,000	1987	13	1.158	502,000	132,000	42.2	22,300	5,880	138,000
21		1988	12	1.103	512,000	135,000	44.3	23,500	6,200	141,000
22	400,000	1987	11	1.158	463,000	122,000	46.4	24,600	6,490	128,000
33		1988	12	1.103	864,000	228,000	69.6	36,900	9,700	238,000
80		1988	12	1.103	1,660,000	437,000	169	89,300	23,600	461,000
80	1,400,000	1987	13	1.158	1,620,000	427,000	169	89,300	23,600	451,000
136		1988	12	1.103	2,450,000	645,000	287	152,000	40,100	685,000
145		1988	12	1.103	2,740,000	723,000	306	162,000	42,700	766,000

^aReference 12 provided only combined catalyst replacement and disposal costs.

^bScaling factors are based on an inflation rate of 5 percent per year.

^cAnnual costs are based on the assumption that the catalyst will be replaced every 5 years. Therefore, the capital recovery factor is 0.2638, assuming an annual interest rate of 10 percent.

^dIn one SCR application, 175 m³ of catalyst is used with an 83 MW turbine. If the space velocity is the same for any size SCR (assuming the same catalyst), then there is a direct relationship between the amount of catalyst and the exhaust gas flow rate. The exhaust gas flow rate was calculated as equal to the inlet air flow rate, and as Figure B-4 shows, there is nearly a direct relationship between the inlet airflow rate and turbine capacity. Therefore, the catalyst volume for the turbines in this table were estimated assuming there is a direct relationship between the catalyst volume and the turbine output.

^eDisposal costs are estimated based on a unit cost of \$15/ft³.

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OZONE TRANSPORT COMMISSION

OTC Regulatory and Technical Guideline for
Control of Nitrogen Oxides (NO_x) Emissions
from Natural Gas Pipeline Compressor Fuel-
Fired Prime Movers

STATIONARY and AREA SOURCES COMMITTEE

Revised May 14, 2019

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OTC Regulatory and Technical Guideline for Control of Nitrogen Oxides (NO_x) Emissions from Natural Gas Pipeline Compressor Fuel-Fired Prime Movers

This Guideline was developed by the Ozone Transport Commission (OTC) as part of a regional effort to attain and maintain the eight-hour ozone standard, and reduce eight-hour ozone levels.

Notes:

- 1. States opting to promulgate rules based on this Guideline must comply with State specific administrative requirements and procedures.*
- 2. The term <OTC STATE AGENCY> is a placeholder for individual State Agency names.*
- 3. If the owner or operator of a natural gas fueled prime mover subject to this Guideline is unable to comply with the NO_x emissions rate limitations or % NO_x reduction from uncontrolled shown in specified Section 4 of this Guideline, the owner or operator shall submit an alternative NO_x RACT determination, in accordance with Section 5 of this Guideline, for review and approval by the appropriate State Agency which will prepare a revised SIP submittal to the U.S. EPA as required.*

1. Purpose

The purpose of this Guideline is to provide NO_x emissions limitations for existing natural gas fueled prime movers powering compressors used for pipeline transportation of natural gas, and to also provide NO_x emissions limitations for existing natural gas fueled prime movers powering compressors used for the storage (injection and extraction) of natural gas. Control of NO_x emissions from subject sources will help reduce the adverse impact of those emissions on public health, safety, and welfare.

2. Definitions

Note: The definitions used in this section are provided as examples for OTC state agency adoption as needed.

The following words and terms, when used in this Guideline, shall have the following meanings:

- 2.1 Combustion turbine means a device in which expanding gases from the combustion chamber(s) drive the blades of a turbine to generate mechanical energy in the form of a rotating shaft.
- 2.2 Compressor means a mechanical device (including, but not limited to reciprocating, axial flow, centrifugal, etc.) designed to increase the pressure of the natural gas in order to facilitate the movement of the natural gas through a pipeline.

- 2.3 Existing means the natural gas fueled compressor prime mover was in operation no later than MM-DD-YYYY in any location.
- 2.4 Field gathering means taking natural gas from the wellhead, and sometimes boosting the natural gas pressure from the wellhead pressure, and injecting the natural gas into field gathering pipelines to transport the natural gas to processing facilities and/or to inject the natural gas into the transport pipelines.
- 2.5 Four stroke (4S) means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.
- 2.6 Lean burn (LB) means any two-stroke or four-stroke spark ignited reciprocating internal combustion engine that does not meet the definition of a rich burn engine.
- 2.7 Nameplate rating means: for reciprocating engine natural gas fueled compressor prime movers, the manufacturer's design maximum capacity in horsepower (hp) at the installation site conditions, and for combustion turbine natural gas fuel compressor prime movers, the manufacturer's design maximum capacity at International Organization for Standardization (ISO) 2533 conditions (59° Fahrenheit or 288 Kelvin, 60% relative humidity, and 101.3 kilopascals of pressure). Starting from the completion of any physical change in the prime mover resulting in an increase in the maximum output (in hp) that the prime mover is capable of producing on a steady state basis and during continuous operation, such increased maximum output (at site location conditions for reciprocating prime movers and ISO conditions for combustion turbine prime movers) shall be as specified by the person conducting the physical change.
- 2.8 Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.
- 2.9 Natural gas fueled means that $\geq 90\%$ of the prime mover's heat input, excluding recirculated or recuperated exhaust heat, is derived from the combustion of natural gas.
- 2.10 Operator means any person who operates, controls, or supervises a natural gas fueled prime mover subject to this Guideline and shall include, but not be limited to, any holding company, utility system, or plant manager of such natural gas fueled prime mover.
- 2.11 Owner means any holder of any portion of the legal or equitable title in a natural gas fueled prime mover subject to this Guideline.

- 2.12 Pipeline transportation of natural gas means the movement of natural gas through an interconnected network of compressors and pipeline components, from field gathering networks near wellheads to end users, including:
- a. The compressor and pipeline network used for field gathering of natural gas from the wellheads for delivery to either processing facilities or connections to pipelines used for intrastate or interstate transportation of the natural gas.
 - b. The compressor and pipeline network used to transport the natural gas from field gathering networks or processing facilities over a distance (intrastate or interstate) to and from storage facilities, to large natural gas end-users, and to distribution organizations that provide the natural gas to end-users.
- 2.13 Prime mover means a spark-ignited reciprocating internal combustion engine or combustion turbine.
- 2.14 Reasonably available control technology (RACT) means the lowest emission limit for NO_x that a particular source is capable of meeting by the application of NO_x emissions control technology that is reasonably available considering technological and economic feasibility.
- 2.15 Reciprocating internal combustion engine means a reciprocating engine in which power, produced by heat and/or pressure that is developed in the engine combustion chambers by the burning of a mixture of air and fuel, is subsequently converted to mechanical work.
- 2.16 Rich burn (RB) means any four-stroke spark ignited reciprocating internal combustion engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Internal combustion engines originally manufactured as rich burn engines, but modified with passive emission control technology for NO_x (such as pre-combustion chambers) will be considered lean burn engines. Also, existing internal combustion engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.
- 2.17 Spark ignited means a reciprocating internal combustion engine utilizing a spark plug (or other sparking device) to ignite the air/fuel mixture and with operating characteristics significantly similar to the theoretical Otto combustion cycle.
- 2.18 Shutdown means the period of unit operation between when the compressor prime mover has been unloaded to the minimum load and when the combustion of fuel in the prime mover has ceased.
- 2.19 Startup means the period of unit operation between when fuel combustion commences in the prime mover and when the compressor prime mover has been loaded to its minimum load.

- 2.20 Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.
- 2.21 Two stroke (2S) means a type of reciprocating internal combustion engine which completes the power cycle in a single crankshaft revolution by combining the intake and compression operations into one stroke (one-half revolution) and the power and exhaust operations into a second stroke. This system requires auxiliary exhaust scavenging of the combustion products and inherently runs lean (excess of air) of stoichiometry.
- 2.22 Uncontrolled means the full load ($\pm 25\%$ of nameplate rating) NO_x emissions rate of a natural gas fueled compressor prime mover prior to the installation of any NO_x controls, including NO_x controls installed during prior NO_x reduction processes, as documented by Continuous Emission Monitoring Systems (CEMS), stack test, or other method or information approved by the <OTC STATE AGENCY>.

3. Applicability

This Guideline is applicable to existing natural gas fueled prime movers powering compressors used for pipeline transportation of natural gas and the underground storage of natural gas.

- 3.1 This Rule does not apply to:
 - 3.1.1 Prime movers with nameplate horse-power ratings of <200 hp.
 - 3.1.2 In accordance with the provisions of Section 7 of this Guideline, natural gas fueled compressor prime movers that operate less than 438 hours per year are exempt from the NO_x emissions limitations and testing requirements of this Guideline provided they meet the applicable requirements of Section 7 of this Guideline.

4. Emissions Limitations

Except as provided for in Section 5 of this Guideline, no later than MM-DD-YYYY, natural gas compressor prime movers subject to this Guideline shall not exceed the following NO_x emissions limits:

- 4.1 For two-stroke lean burn internal combustion engines, the following NO_x emissions limitations are applicable:
 - 4.1.1 Output rating of $200 \text{ HP} \leq \text{nameplate rating} < 500 \text{ HP}$:
 - 4.1.1.1 2.0 g/BHP-hr, or an emissions rate equivalent to 80% reduction from uncontrolled, whichever emissions rate is greater; or
 - 4.1.1.2 An hourly NO_x mass emissions no greater than the mass emissions calculated by multiplying the applicable NO_x emissions

rate from Section 4.1.1.1 of this rule times the prime mover's nameplate rating.

4.1.2 Output rating of 500 HP $\leq$ nameplate rating < 2000 HP:

4.1.2.1 1.5 g/BHP-hr, or an emissions rate equivalent to 80% reduction from uncontrolled, whichever emissions rate is greater; or

4.1.2.2 An hourly NO_x mass emissions no greater than the mass emissions calculated by multiplying the applicable NO_x emissions rate from Section 4.1.2.1 of this rule times the prime mover's nameplate rating.

4.1.3 Nameplate rating of $\geq$ 2000 HP:

4.1.3.1 1.5 g/BHP-hr, or an emissions rate equivalent to 90% reduction from uncontrolled, whichever emissions rate is greater; or

4.1.3.2 An hourly NO_x mass emissions no greater than the mass emissions calculated by multiplying the applicable NO_x emissions rate from Section 4.1.3.1 of this rule times the prime mover's nameplate rating.

4.2 For four stroke lean burn internal combustion engines, the following NO_x emissions limitations are applicable:

4.2.1 Output rating of 200 HP $\leq$ nameplate rating < 500 HP:

4.2.1.1 1.5 g/BHP-hr, or an emissions rate equivalent to 90% reduction from uncontrolled, whichever emissions rate is greater; or

4.2.1.2 An hourly NO_x mass emissions no greater than the mass emissions calculated by multiplying the applicable NO_x emissions rate from Section 4.2.1.1 of this rule times the prime mover's nameplate rating.

4.2.2 Output rating of 500 HP $\leq$ nameplate rating < 2000 HP:

4.2.2.1 1.5 g/BHP-hr, or an emissions rate equivalent to 90% reduction from uncontrolled, whichever emissions rate is greater; or

4.2.2.2 An hourly NO_x mass emissions no greater than the mass emissions calculated by multiplying the applicable NO_x emissions rate from Section 4.2.2.1 of this rule times the prime mover's nameplate rating.

4.2.3 Nameplate rating of 2000 HP or more:

4.2.3.1 1.5 g/BHP-hr, or an emissions rate equivalent to 90% reduction from uncontrolled, whichever emissions rate is greater; or

4.2.3.2 An hourly NO_x mass emissions no greater than the mass emissions calculated by multiplying the applicable NO_x emissions

rate from Section 4.2.3.1 of this rule times the prime mover's nameplate rating.

4.3 For four stroke rich burn internal combustion engines, the following NO_x emissions limitations are applicable:

4.3.1 Output rating of $200 \text{ HP} \leq \text{nameplate rating} < 500 \text{ HP}$:

4.3.1.1 1.5 g/BHP-hr, or an emissions rate equivalent to 90% reduction from uncontrolled, whichever emissions rate is greater; or

4.3.1.2 An hourly NO_x mass emissions no greater than the mass emissions calculated by multiplying the applicable NO_x emissions rate from Section 4.3.1.1 of this rule times the prime mover's nameplate rating.

4.3.2 Output rating of $500 \text{ HP} \leq \text{nameplate rating} < 2000 \text{ HP}$:

4.3.2.1 1.5 g/BHP-hr, or an emissions rate equivalent to 90% reduction from uncontrolled, whichever emissions rate is greater; or

4.3.2.2 An hourly NO_x mass emissions no greater than the mass emissions calculated by multiplying the applicable NO_x emissions rate from Section 4.3.2.1 of this rule times the prime mover's nameplate rating.

4.3.3 Nameplate rating of $\geq 2000 \text{ HP}$:

4.3.3.1 1.0 g/BHP-hr, or an emissions rate equivalent to 95% reduction from uncontrolled, whichever emissions rate is greater; or

4.3.3.2 An hourly NO_x mass emissions no greater than the mass emissions calculated by multiplying the applicable NO_x emissions rate from Section 4.3.3.1 of this rule times the prime mover's nameplate rating.

4.4 For combustion turbines, the following NO_x emissions limitations are applicable:

4.4.1 Nameplate rating of less than 2000 HP:

4.4.1.1 150 ppmvd @ 15% O₂, or 80% reduction from uncontrolled, whichever emissions rate is greater; or

4.4.1.2 An hourly NO_x mass emissions no greater than the mass emissions equivalent of the combustion turbine operating at its nameplate rating at the applicable NO_x emissions rate from Section 4.4.1.1 of this rule.

4.4.2 Output rating of $2000 \text{ HP} \leq \text{nameplate rating} < 5000 \text{ HP}$:

4.4.2.1 50 ppmvd @ 15% O₂, or 80% reduction from uncontrolled, whichever emissions rate is greater; or

4.4.2.2 An hourly NO_x mass emissions no greater than the mass emissions equivalent of the combustion turbine operating at its nameplate rating at the applicable NO_x emissions rate from Section 4.4.2.1 of this rule.

4.4.3 Nameplate rating of 5000 HP or more:

4.4.3.1 25 ppmvd @ 15% O₂, or 80% reduction from uncontrolled, whichever emissions rate is greater; or

4.4.3.2 An hourly NO_x mass emissions no greater than the mass emissions equivalent of the combustion turbine operating at its nameplate rating at the applicable NO_x emissions rate from Section 4.4.3.1 of this rule.

Table 1 NO_x LIMITS*

Two-Stroke Lean Burn ICE

Nameplate Rating (HP)	NO _x Rate (g/BHP-hr) or (% Reduction)
200 - 499	2.0 (80%)
500 - 1999	1.5 (80%)
≥2000	1.5 (90%)

Four-Stroke Lean Burn ICE

Nameplate Rating (HP)	NO _x Rate (g/BHP-hr) or (% Reduction)
200 - 499	1.5 (90%)
500 - 1999	1.5 (90%)
≥2000	1.5 (90%)

Four-Stroke Rich Burn ICE

Nameplate Rating (HP)	NO _x Rate (g/BHP-hr) or (% Reduction)
200 - 499	1.5 (90%)
500 - 1999	1.5 (90%)
≥2000	1.0 (95%)

Combustion Turbines**

Nameplate Rating (HP) (MW)	NO _x Rate (ppmvd @ 15% O ₂)
≤2000 (1.5)	150.0 (6.0 lb/MWhr)
2000 - 4999 (1.5-3.7)	50.0 (2.0 lb/MWhr)
≥5000 (3.7)	25.0 (1.0 lb/MWhr)

Notes:

*If the owner or operator of a natural gas fueled prime mover subject to this Guideline is unable to comply with the NO_x emissions rate limitations or % NO_x reduction from uncontrolled shown in Table 1 above and specified Section 4 of this Guideline, the owner or operator shall submit an alternative NO_x RACT determination, in accordance with Section 5 of this Guideline, for review and approval by the appropriate State Agency which will prepare a revised SIP submittal to the U.S. EPA as required.

**Combustion Turbine NO_x rates are from 40 CFR 60 Subpart KKKK Table 1¹.

- 4.5 The emissions limitations of Sections 4.1 through 4.4 of this Guideline are applicable during all periods of natural gas fueled compressor prime mover operation, except:
 - 4.5.1 Reserved.
 - 4.5.2 Combustion turbine prime movers operating at ambient temperatures less than 0° F.
 - 4.5.3 Combustion turbine prime movers operating below the effective NO_x control range of any installed low-NO_x combustion controls.
 - 4.5.4 Natural gas fueled compressor prime movers utilizing post-combustion NO_x controls operating at loads below the effective NO_x control range of the installed post-combustion controls.
 - 4.4.5 During periods of operation covered by Sections 4.5.1 through 4.5.4 of this Guideline, hourly NO_x mass emissions shall not exceed the hourly NO_x mass emissions equivalent to the combustion turbine operating at its nameplate rating at the applicable NO_x emissions rate from Sections 4.4.1.1, 4.4.2.1, or 4.4.3.1 of this rule.

5. Alternative RACT Emissions Limitation Determination

- 5.1 If the owner or operator of a natural gas fueled prime mover subject to this Guideline is unable to comply with the emissions rate limitations of Section 4 of this Guideline, the owner or operator shall submit an alternative NO_x RACT determination, in accordance with Section 5 of this Guideline, for review and approval by the <OTC STATE AGENCY> and for the <OTC STATE AGENCY> to prepare a revised SIP submittal to the USEPA as required.
 - 5.1.1 An alternative RACT proposal may address the NO_x emissions from a specific, single natural gas fueled prime mover, or
 - 5.1.2 An alternative RACT proposal may address NO_x emissions averaging of multiple natural gas fueled prime movers under the control of a common

¹ 40 CFR Appendix Table 1 to Subpart KKKK of Part 60, Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines. <https://www.gpo.gov/fdsys/pkg/CFR-2014-title40-vol7/pdf/CFR-2014-title40-vol7-part60-subpartKKKK-app1.pdf>

owner or operator at a single facility to achieve the same level of NO_x reductions that would be achieved if all of the natural gas fueled prime movers at the location met the applicable NO_x emissions limitations of Section 4 of this rule.

- 5.2 Alternative RACT determinations made pursuant to Section 5.1 of this Guideline shall be submitted to <OTC STATE AGENCY> no later than MM-DD-YYYY for review and approval.
- 5.3 An alternative NO_x RACT determination submitted in accordance with Section 5.1 of this Guideline shall include, as a minimum, the following information:
 - 5.3.1 The name and address of the owner and operator
 - 5.3.2 The address of the subject natural gas compressor prime mover
 - 5.3.3 Latitude and longitude coordinates of the subject natural gas compressor prime mover
 - 5.3.4 Prime mover technical information including
 - 5.3.4.1 Prime mover manufacturer
 - 5.3.4.2 Prime mover model
 - 5.3.4.3 Prime mover serial number
 - 5.3.4.4 Prime mover configuration (combustion turbine, two stroke lean burn, four stroke lean burn, four stroke rich burn)
 - 5.3.4.5 Prime mover original installation/startup date
 - 5.3.4.6 Prime mover nameplate power rating
 - 5.3.4.7 NO_x emissions controls
 - 5.3.4.8 Actual, if available, or estimated NO_x emissions rate
 - 5.3.5 Identification of the available NO_x control technologies, the projected effectiveness of the technologies considered, and the estimated costs for installation and operation for each of the technologies
 - 5.3.6 If applicable, description and discussion of any previous NO_x reduction modifications, changes in operating practices, etc
 - 5.3.7 Identification of equipment or process modifications that are proposed as RACT for implementation on the subject natural gas fueled prime mover, including a technical evaluation and an economic evaluation supporting the selection of the proposed RACT
 - 5.3.8 Expected NO_x emission rate(s) for the range of normal operation of the subject natural gas fueled prime mover.
 - 5.3.9 Proposed testing, monitoring, and reporting procedures
 - 5.3.10 The NO_x emission rates for the subject existing natural gas fueled prime movers, prior to implementation of the alternative RACT, established with

approved Continuous Emission Monitoring Systems (CEMS), stack test, or other method approved by the <OTC STATE AGENCY>.

5.3.11 Proposed implementation schedule.

5.3.12 Any other information requested by the <OTC STATE AGENCY>.

6. Testing Requirements

6.1 The owner or operator shall conduct an initial performance test to demonstrate compliance with the applicable NO_x emissions limitations of Section 4 of this Guideline no later than MM-DD-YYYY.

6.1.1 The owner or operator shall submit a test protocol to the <OTC STATE AGENCY> at least 30 days prior to emissions testing.

6.2.2 The test methodology shall meet the applicable requirements of 40 CFR Part 60, Appendix A, and the guidance of 40 CFR Part 60 Subpart GG for combustion turbines and the guidance of 40 CFR Part 60 Subpart JJJ for spark ignited internal combustion engines.

6.2.3 The owner or operator shall submit a compliance test report containing the results of the emissions test to the <OTC STATE AGENCY> no later than 60 days following completion of the emissions test.

6.2 The owner or operator of a natural gas compressor prime mover subject to an alternative RACT emissions limitation in accordance with the provisions of Section 5 of this Guideline shall conduct an initial performance test to demonstrate compliance with the provisions of the approved RACT determination.

6.2.1 The owner or operator shall submit a test protocol to the <OTC STATE AGENCY> at least 30 days prior to emissions testing.

6.2.2 The test methodology shall meet the applicable requirements of 40 CFR Part 60, Appendix A, and the guidance of 40 CFR Part 60 Subpart GG for combustion turbines and the guidance of 40 CFR Part 60 Subpart JJJ for spark ignited internal combustion engines.

6.2.3 The owner or operator shall submit a compliance test report containing the results of the emissions test to the <OTC STATE AGENCY> no later than 60 days following completion of the emissions test.

6.3 Except as provided in Section 6.4, at least twice per year the owner or operator shall conduct periodic NO_x emissions testing of subject natural gas fueled compressor prime movers to demonstrate compliance with the applicable NO_x emissions limitations of Section 5 of this Guideline or the applicable alternative RACT NO_x emission rate determined in accordance with Section 6 of this Guideline.

- 6.3.1 The use of reference method equivalent portable analyzers is acceptable provided the portable analyzer is certified using appropriate reference method procedures in 40 CFR Part 60, Appendix A.
- 6.3.2 The owner or operator shall submit a test protocol to the <OTC STATE AGENCY> for review and approval prior to the first NO_x emission test conducted in compliance with Section 6.3 as follows:
 - 6.3.2.1 Test protocols utilizing reference test methods shall be submitted at least 30 days prior to the conduct of the emissions testing.
 - 6.3.2.2 Test protocols utilizing reference method equivalent analyzers shall be submitted at least 30 days prior to the conduct of the first periodic emissions test under Section 6.3 using the reference method equivalent analyzer.
 - 6.3.2.3 Test protocols utilizing reference method equivalent analyzers for testing subsequent to the first periodic emissions test conducted under Section 6.3 utilizing reference method equivalent analyzers are not required to be submitted to the <OTC STATE AGENCY> provided no changes to the protocol have been made subsequent to the initial <OTC STATE AGENCY> approval of such first period emissions test.
- 6.3.3 The owner or operator shall submit a test report containing the results of the emissions test to the <OTC STATE AGENCY> no later than 30 days following the completion of the emissions test.
- 6.3.4 Following the conduct of an initial periodic performance test conducted in accordance with Section 6.3, subsequent period performance tests conducted in accordance with Section 6.3 shall be conducted no less than 90 days following the conduct of the most recent NO_x emissions performance test.
- 6.3.5 NO_x emissions testing in compliance with the requirements of Section 6.3 of this Guideline may be conducted at any normal operating load from 40% to 100% of the subject natural gas fueled compressor prime mover's nameplate rating.
- 6.3.6 Each compliance test must include three test runs where each run lasts at least one hour. Compliance is demonstrated by the average of the three 1-hour or longer test runs.
- 6.4 If a natural gas fueled compressor prime mover demonstrates compliance with the applicable NO_x emission limit of Section 5 or Section 6 of this Guideline for three consecutive tests, the testing frequency requirements of Section 6.3 of this Guideline may be reduced from at least twice per year to at least once per year.

- 6.4.1 If a natural gas fueled compressor prime mover that has met the requirements to reduce testing in accordance with Section 6.4 of this Guideline fails to demonstrate compliance with applicable NOx emission limits in any subsequent emissions test, that natural gas compressor prime mover shall meet the testing frequency requirements of Section 6.3 of this Guideline.
 - 6.4.1.1 If the compliance demonstration failure occurs during the first half of a calendar year, the testing frequency requirements of Section 6.3 become effective during that calendar year.
 - 6.4.1.2 If the compliance demonstration failure occurs during the second half of a calendar year, the testing frequency requirements of Section 6.3 become effective during the subsequent calendar year.
- 6.4.2 All other testing requirements of Section 6.3 remain unchanged.
- 6.4.3 There are no limits on the number of time a natural gas fueled compressor prime mover may qualify for reduced testing frequency in accordance with Section 6.4 of this Guideline.

7. Exemptions

- 7.1 Natural gas fueled compressor prime movers that operate 438 or fewer hours per year are exempt from the emissions limitation requirements of Sections 4 and 5 of this Guideline and are exempt from the testing requirements of Section 6 of this Guideline.
- 7.2 The owner or operator of a natural gas fueled compressor prime mover seeking exemption in accordance with Section 7.1 of this Guideline shall install a non-resettable operating hour metering device on the prime mover. Annual operating hours for the natural gas fueled compressor prime mover shall be monitored, recorded, and reported to <OTC STATE AGENCY> no later than March 31 of each subsequent calendar year in accordance with the reporting requirements of Section 9.3 of this Guideline.
- 7.3 A natural gas fueled compressor prime mover that was previously exempt in accordance with Section 7.1 of this Guideline shall permanently lose that exemption if the natural gas fueled compressor prime mover exceeds 438 hours per year of operation in any calendar year.
 - 7.3.1 The owner or operator shall submit a plan for the natural gas compressor prime mover's compliance with all applicable requirements of this Guideline no later than March 31 of the year following the calendar year in

which the natural gas fueled compressor prime mover's exceeded 438 hours of annual operation.

- 7.3.2 Compliance with all applicable requirements of this Guideline shall be attained no later than December 31 of the year following the calendar year that the natural gas fueled compressor prime mover exceeded 438 hours of annual operation.
- 7.4 If a natural gas fueled compressor prime mover subject to this Guideline is required by state or federal regulation to monitor and report NOx emissions utilizing <OTC STATE AGENCY> approved CEMS, or the owner or operator of a natural gas fueled compressor prime mover subject to this Guideline elects to monitor and report NOx emissions utilizing <OTC STATE AGENCY> approved CEMS, the owner or operator of the subject natural gas fueled compressor prime mover may petition the <OTC STATE AGENCY> for exemption from the testing requirements of Section 6.3 of this Guideline.

8. Other Requirements

- 8.1 The owner or operator of a natural gas fueled compressor prime mover subject to this Guideline shall follow an inspection and maintenance plan, incorporating appropriate operating and maintenance experience and any applicable prime mover and emission control manufacturer recommendations, to ensure proper maintenance of the natural gas fueled compressor prime mover and related NOx emissions control equipment in a manner consistent with good air pollution control practices for minimizing emissions. Records and documentation supporting the inspection and maintenance plan shall be permanently maintained at the source facility. Records of inspections and maintenance performed shall be maintained as required by Section 9.1 of this Guideline.
- 8.2 The owner or operator shall follow operating practices and procedures for the natural gas fueled compressor prime mover and related emissions controls consistent with good air pollution control practices for minimizing NOx emissions across the entire load range of the natural gas fueled compressor prime mover, including, as much as practical, periods of startup, shutdown, and malfunction. Records and documentation supporting the subject operating practices and procedures shall be permanently maintained at the source facility.
- 8.3 If a natural gas fueled compressor prime mover requires major maintenance and natural gas system conditions require the temporary replacement of the natural gas fueled compressor prime mover, a temporary replacement prime mover may be installed as follows:

- 8.3.1 The temporary replacement natural gas fueled compressor prime mover shall be similar to the prime mover being temporarily replaced, with similar NOx emissions controls and expected NOx emissions characteristics.
- 8.3.2 If the temporary replacement natural gas fueled compressor prime mover remains installed for a period exceeding 3 months
 - 8.3.2.1 The temporary replacement natural gas fueled compressor prime mover shall meet the applicable NOx emissions limits specified in Section 4 of this Guideline
 - 8.3.2.2 Compliance with the applicable NOx emissions limitations shall be demonstrated by NOx emissions testing in accordance with the requirements of Section 6.1 of this Guideline, except the testing shall take place within 30 days of exceeding the 3 months temporary replacement period
- 8.3.3 The owner or operator of a natural gas fueled compressor prime mover shall notify the <OTC STATE AGENCY> of a temporary prime mover replacement within 5 working days of performing the temporary replacement.
- 8.3.4 The owner or operator of a natural gas fueled compressor prime mover that is being returned to service after temporary replacement shall:
 - 8.3.4.1 Notify the <OTC STATE AGENCY> within 5 working days of the prime movers return to service
 - 8.3.4.2 Demonstrate compliance with the applicable NOx emissions limitations by NOx emissions testing conducted in accordance with Section 6.1 of this Guideline, except the performance test shall be conducted within 30 days of the return to service date.
- 8.4 If a natural gas fueled compressor prime mover is replaced as part of a routine maintenance prime mover exchange program, a replacement prime mover may be installed as follows:
 - 8.3.1 The replacement natural gas fueled compressor prime mover shall be similar to the prime mover being temporarily replaced, with similar NOx emissions controls and expected NOx emissions characteristics.
 - 8.3.1.1 The replacement natural gas fueled compressor prime mover shall meet the applicable NOx emissions limits specified in Section 4 of this Guideline or alternative NOx RACT plan approved in accordance with Section 5 of this Guideline.
 - 8.3.1.2 Compliance with the applicable NOx emissions limitations shall be demonstrated by NOx emissions testing in accordance with the requirements of Section 6.2 of this Guideline, except the testing

shall take place within 30 days of the replacement natural gas fueled compressor prime mover's initial startup after installation.

- 8.3.2 The owner or operator of a natural gas fueled compressor prime mover shall notify the <OTC STATE AGENCY> of a natural gas fueled compressor prime mover replacement within 5 working days of performing the replacement.

9. Recordkeeping and Reporting

- 9.1 The owner or operator of a natural gas fueled compressor prime mover subject to this Guideline shall maintain all records necessary for determining compliance with the provisions of this Guideline at the facility for a period of at least five years, unless otherwise specified in this Guideline.
- 9.2 No later than MM-DD-YYYY the owner or operator of a natural gas fueled compressor prime mover subject to this Guideline shall submit an initial compliance evaluation to the <OTC STATE AGENCY> for review and approval. The initial compliance evaluation shall include, as a minimum, the following information:
- 9.2.1 The name and address of the owner and operator
 - 9.2.2 The address of the subject natural gas compressor prime mover
 - 9.2.3 Longitude and latitude coordinates of the subject natural gas compressor prime mover
 - 9.2.4 Prime mover technical information including
 - 9.2.4.1 Prime mover manufacturer
 - 9.2.4.2 Prime mover model
 - 9.2.4.3 Prime mover serial number
 - 9.2.4.4 Prime mover configuration (combustion turbine, two stroke lean burn, four stroke lean burn, four stroke rich burn)
 - 9.2.4.5 Prime mover original installation/startup date
 - 9.2.4.6 Prime mover nameplate power rating
 - 9.2.4.7 NOx emissions controls
 - 9.2.4.8 Actual, if available, or estimated NOx emissions rate
 - 9.2.5 Plan for compliance with the requirements of this Guideline
 - 9.2.5.1 Proposed compliance strategy or identification of proposed NOx controls
 - 9.2.5.2 Estimated NOx emissions after installation of controls or strategy
 - 9.2.5.3 Proposed compliance schedule

- 9.2.6 Any other information requested by the <OTC STATE AGENCY>.
- 9.2.7 An alternative RACT emission limitation determination submitted in compliance with the requirements of Section 5 of this Guideline shall fulfill the initial compliance evaluation submittal requirements of Section 9.2 of this Guideline.
- 9.3 Beginning on MM-DD-YYYY, on March 31 of each calendar year the owner or operator of a natural gas fueled compressor prime mover subject to this Guideline shall submit an annual report to the <OTC STATE AGENCY> containing the following information:
 - 9.3.1 The name and address of the owner and operator
 - 9.3.2 The address of the subject natural gas fueled compressor prime mover
 - 9.3.3 Longitude and latitude coordinates of the subject natural gas compressor prime mover
 - 9.3.4 Identification of the subject natural gas fueled compressor prime mover
 - 9.3.5 Statement of compliance with the applicable emission rate limitations of this Guideline
 - 9.3.6 Statement of compliance regarding the conduct of maintenance and operations in a manner consistent with good air pollution control practices for minimizing emissions, as established in accordance with Section 8 of this Guideline.
 - 9.3.7 For subject natural gas fueled compressor prime movers seeking exemption for prime movers operating less than 438 hours per year in accordance with the requirements of Section 8 of this Guideline, provide applicable hour-meter readings and the calculated prime mover operating hours for the previous calendar year.
 - 9.3.8 If applicable, a statement documenting any change in the operating characteristics of the subject natural gas fueled compressor prime mover.
 - 9.3.9 A statement certifying that the information included in the annual report is complete and accurate.
 - 9.3.10 The annual reports for multiple subject natural gas fueled compressor prime movers at a single source may be combined into a single annual report.

3.3 Gasoline And Diesel Industrial Engines

3.3.1 General

The engine category addressed by this section covers a wide variety of industrial applications of both gasoline and diesel internal combustion (IC) engines such as aerial lifts, fork lifts, mobile refrigeration units, generators, pumps, industrial sweepers/scrubbers, material handling equipment (such as conveyors), and portable well-drilling equipment. The three primary fuels for reciprocating IC engines are gasoline, diesel fuel oil (No.2), and natural gas. Gasoline is used primarily for mobile and portable engines. Diesel fuel oil is the most versatile fuel and is used in IC engines of all sizes. The rated power of these engines covers a rather substantial range, up to 250 horsepower (hp) for gasoline engines and up to 600 hp for diesel engines. (Diesel engines greater than 600 hp are covered in Section 3.4, "Large Stationary Diesel And All Stationary Dual-fuel Engines".) Understandably, substantial differences in engine duty cycles exist. It was necessary, therefore, to make reasonable assumptions concerning usage in order to formulate some of the emission factors.

3.3.2 Process Description

All reciprocating IC engines operate by the same basic process. A combustible mixture is first compressed in a small volume between the head of a piston and its surrounding cylinder. The mixture is then ignited, and the resulting high-pressure products of combustion push the piston through the cylinder. This movement is converted from linear to rotary motion by a crankshaft. The piston returns, pushing out exhaust gases, and the cycle is repeated.

There are 2 methods used for stationary reciprocating IC engines: compression ignition (CI) and spark ignition (SI). This section deals with both types of reciprocating IC engines. All diesel-fueled engines are compression ignited, and all gasoline-fueled engines are spark ignited.

In CI engines, combustion air is first compression heated in the cylinder, and diesel fuel oil is then injected into the hot air. Ignition is spontaneous because the air temperature is above the autoignition temperature of the fuel. SI engines initiate combustion by the spark of an electrical discharge. Usually the fuel is mixed with the air in a carburetor (for gasoline) or at the intake valve (for natural gas), but occasionally the fuel is injected into the compressed air in the cylinder.

CI engines usually operate at a higher compression ratio (ratio of cylinder volume when the piston is at the bottom of its stroke to the volume when it is at the top) than SI engines because fuel is not present during compression; hence there is no danger of premature autoignition. Since engine thermal efficiency rises with increasing pressure ratio (and pressure ratio varies directly with compression ratio), CI engines are more efficient than SI engines. This increased efficiency is gained at the expense of poorer response to load changes and a heavier structure to withstand the higher pressures.¹

3.3.3 Emissions

Most of the pollutants from IC engines are emitted through the exhaust. However, some total organic compounds (TOC) escape from the crankcase as a result of blowby (gases that are vented from the oil pan after they have escaped from the cylinder past the piston rings) and from the fuel tank and carburetor because of evaporation. Nearly all of the TOCs from diesel CI engines enter the

atmosphere from the exhaust. Evaporative losses are insignificant in diesel engines due to the low volatility of diesel fuels.

The primary pollutants from internal combustion engines are oxides of nitrogen (NO_x), total organic compounds (TOC), carbon monoxide (CO), and particulates, which include both visible (smoke) and nonvisible emissions. Nitrogen oxide formation is directly related to high pressures and temperatures during the combustion process and to the nitrogen content, if any, of the fuel. The other pollutants, HC, CO, and smoke, are primarily the result of incomplete combustion. Ash and metallic additives in the fuel also contribute to the particulate content of the exhaust. Sulfur oxides (SO_x) also appear in the exhaust from IC engines. The sulfur compounds, mainly sulfur dioxide (SO_2), are directly related to the sulfur content of the fuel.²

3.3.3.1 Nitrogen Oxides -

Nitrogen oxide formation occurs by two fundamentally different mechanisms. The predominant mechanism with internal combustion engines is thermal NO_x which arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most thermal NO_x is formed in the high-temperature region of the flame from dissociated molecular nitrogen in the combustion air. Some NO_x , called prompt NO_x , is formed in the early part of the flame from reaction of nitrogen intermediary species, and HC radicals in the flame. The second mechanism, fuel NO_x , stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Gasoline, and most distillate oils have no chemically-bound fuel N_2 and essentially all NO_x formed is thermal NO_x .

3.3.3.2 Total Organic Compounds -

The pollutants commonly classified as hydrocarbons are composed of a wide variety of organic compounds and are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. Most unburned hydrocarbon emissions result from fuel droplets that were transported or injected into the quench layer during combustion. This is the region immediately adjacent to the combustion chamber surfaces, where heat transfer outward through the cylinder walls causes the mixture temperatures to be too low to support combustion.

Partially burned hydrocarbons can occur because of poor air and fuel homogeneity due to incomplete mixing, before or during combustion; incorrect air/fuel ratios in the cylinder during combustion due to maladjustment of the engine fuel system; excessively large fuel droplets (diesel engines); and low cylinder temperature due to excessive cooling (quenching) through the walls or early cooling of the gases by expansion of the combustion volume caused by piston motion before combustion is completed.²

3.3.3.3 Carbon Monoxide -

Carbon monoxide is a colorless, odorless, relatively inert gas formed as an intermediate combustion product that appears in the exhaust when the reaction of CO to CO_2 cannot proceed to completion. This situation occurs if there is a lack of available oxygen near the hydrocarbon (fuel) molecule during combustion, if the gas temperature is too low, or if the residence time in the cylinder is too short. The oxidation rate of CO is limited by reaction kinetics and, as a consequence, can be accelerated only to a certain extent by improvements in air and fuel mixing during the combustion process.²⁻³

3.3.3.4 Smoke and Particulate Matter -

White, blue, and black smoke may be emitted from IC engines. Liquid particulates appear as white smoke in the exhaust during an engine cold start, idling, or low load operation. These are formed in the quench layer adjacent to the cylinder walls, where the temperature is not high enough to ignite the fuel. Blue smoke is emitted when lubricating oil leaks, often past worn piston rings, into the combustion chamber and is partially burned. Proper maintenance is the most effective method of preventing blue smoke emissions from all types of IC engines. The primary constituent of black smoke is agglomerated carbon particles (soot) formed in regions of the combustion mixtures that are oxygen deficient.²

3.3.3.5 Sulfur Oxides -

Sulfur oxides emissions are a function of only the sulfur content in the fuel rather than any combustion variables. In fact, during the combustion process, essentially all the sulfur in the fuel is oxidized to SO_2 . The oxidation of SO_2 gives sulfur trioxide (SO_3), which reacts with water to give sulfuric acid (H_2SO_4), a contributor to acid precipitation. Sulfuric acid reacts with basic substances to give sulfates, which are fine particulates that contribute to PM-10 and visibility reduction. Sulfur oxide emissions also contribute to corrosion of the engine parts.²⁻³

3.3.4 Control Technologies

Control measures to date are primarily directed at limiting NO_x and CO emissions since they are the primary pollutants from these engines. From a NO_x control viewpoint, the most important distinction between different engine models and types of reciprocating engines is whether they are rich-burn or lean-burn. Rich-burn engines have an air-to-fuel ratio operating range that is near stoichiometric or fuel-rich of stoichiometric and as a result the exhaust gas has little or no excess oxygen. A lean-burn engine has an air-to-fuel operating range that is fuel-lean of stoichiometric; therefore, the exhaust from these engines is characterized by medium to high levels of O_2 . The most common NO_x control technique for diesel and dual-fuel engines focuses on modifying the combustion process. However, selective catalytic reduction (SCR) and nonselective catalytic reduction (NSCR) which are post-combustion techniques are becoming available. Controls for CO have been partly adapted from mobile sources.⁴

Combustion modifications include injection timing retard (ITR), preignition chamber combustion (PCC), air-to-fuel ratio adjustments, and derating. Injection of fuel into the cylinder of a CI engine initiates the combustion process. Retarding the timing of the diesel fuel injection causes the combustion process to occur later in the power stroke when the piston is in the downward motion and combustion chamber volume is increasing. By increasing the volume, the combustion temperature and pressure are lowered, thereby lowering NO_x formation. ITR reduces NO_x from all diesel engines; however, the effectiveness is specific to each engine model. The amount of NO_x reduction with ITR diminishes with increasing levels of retard.⁴

Improved swirl patterns promote thorough air and fuel mixing and may include a precombustion chamber (PCC). A PCC is an antechamber that ignites a fuel-rich mixture that propagates to the main combustion chamber. The high exit velocity from the PCC results in improved mixing and complete combustion of the lean air/fuel mixture which lowers combustion temperature, thereby reducing NO_x emissions.⁴

The air-to-fuel ratio for each cylinder can be adjusted by controlling the amount of fuel that enters each cylinder. At air-to-fuel ratios less than stoichiometric (fuel-rich), combustion occurs under conditions of insufficient oxygen which causes NO_x to decrease because of lower oxygen and lower temperatures. Derating involves restricting the engine operation to lower than normal levels of power production for the given application. Derating reduces cylinder pressures and temperatures, thereby lowering NO_x formation rates.⁴

SCR is an add-on NO_x control placed in the exhaust stream following the engine and involves injecting ammonia (NH₃) into the flue gas. The NH₃ reacts with NO_x in the presence of a catalyst to form water and nitrogen. The effectiveness of SCR depends on fuel quality and engine duty cycle (load fluctuations). Contaminants in the fuel may poison or mask the catalyst surface causing a reduction or termination in catalyst activity. Load fluctuations can cause variations in exhaust temperature and NO_x concentration which can create problems with the effectiveness of the SCR system.⁴

NSCR is often referred to as a three-way conversion catalyst system because the catalyst reactor simultaneously reduces NO_x, CO, and HC and involves placing a catalyst in the exhaust stream of the engine. The reaction requires that the O₂ levels be kept low and that the engine be operated at fuel-rich air-to-fuel ratios.⁴

The most accurate method for calculating such emissions is on the basis of "brake-specific" emission factors (pounds per horsepower-hour [lb/hp-hr]). Emissions are the product of the brake-specific emission factor, the usage in hours, the rated power available, and the load factor (the power actually used divided by the power available). However, for emission inventory purposes, it is often easier to assess this activity on the basis of fuel used.

Once reasonable usage and duty cycles for this category were ascertained, emission values were aggregated to arrive at the factors for criteria and organic pollutants presented. Factors in Table 3.3-1 are in pounds per million British thermal unit (lb/MMBtu). Emission data for a specific design type were weighted according to estimated material share for industrial engines. The emission factors in these tables, because of their aggregate nature, are most appropriately applied to a population of industrial engines rather than to an individual power plant. Table 3.3-2 shows unweighted speciated organic compound and air toxic emission factors based upon only 2 engines. Their inclusion in this section is intended for rough order-of-magnitude estimates only.

Table 3.3-3 summarizes whether the various diesel emission reduction technologies (some of which may be applicable to gasoline engines) will generally increase or decrease the selected parameter. These technologies are categorized into fuel modifications, engine modifications, and exhaust after-treatments. Current data are insufficient to quantify the results of the modifications. Table 3.3-3 provides general information on the trends of changes on selected parameters.

3.3.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section.

Supplement A, February 1996

No changes.

Supplement B, October 1996

- Text was revised concerning emissions and controls.
- The CO₂ emission factor was adjusted to reflect 98.5 percent conversion efficiency.

Table 3.3-1. EMISSION FACTORS FOR UNCONTROLLED GASOLINE AND DIESEL INDUSTRIAL ENGINES^a

Pollutant	Gasoline Fuel (SCC 2-02-003-01, 2-03-003-01)		Diesel Fuel (SCC 2-02-001-02, 2-03-001-01)		EMISSION FACTOR RATING
	Emission Factor (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)	Emission Factor (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)	
NO _x	0.011	1.63	0.031	4.41	D
CO	6.96 E-03 ^d	0.99 ^d	6.68 E-03	0.95	D
SO _x	5.91 E-04	0.084	2.05 E-03	0.29	D
PM-10 ^b	7.21 E-04	0.10	2.20 E-03	0.31	D
CO ₂ ^c	1.08	154	1.15	164	B
Aldehydes	4.85 E-04	0.07	4.63 E-04	0.07	D
TOC					
Exhaust	0.015	2.10	2.47 E-03	0.35	D
Evaporative	6.61 E-04	0.09	0.00	0.00	E
Crankcase	4.85 E-03	0.69	4.41 E-05	0.01	E
Refueling	1.08 E-03	0.15	0.00	0.00	E

^a References 2,5-6,9-14. When necessary, an average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr. To convert from lb/hp-hr to kg/kw-hr, multiply by 0.608. To convert from lb/MMBtu to ng/J, multiply by 430. SCC = Source Classification Code. TOC = total organic compounds.

^b PM-10 = particulate matter less than or equal to 10 µm aerodynamic diameter. All particulate is assumed to be ≤ 1 µm in size.

^c Assumes 99% conversion of carbon in fuel to CO₂ with 87 weight % carbon in diesel, 86 weight % carbon in gasoline, average BSFC of 7,000 Btu/hp-hr, diesel heating value of 19,300 Btu/lb, and gasoline heating value of 20,300 Btu/lb.

^d Instead of 0.439 lb/hp-hr (power output) and 62.7 lb/mmBtu (fuel input), the correct emissions factors values are 6.96 E-03 lb/hp-hr (power output) and 0.99 lb/mmBtu (fuel input), respectively. This is an editorial correction. March 24, 2009

Table 3.3-2. SPECIATED ORGANIC COMPOUND EMISSION
FACTORS FOR UNCONTROLLED DIESEL ENGINES^a

EMISSION FACTOR RATING: E

Pollutant	Emission Factor (Fuel Input) (lb/MMBtu)
Benzene ^b	9.33 E-04
Toluene ^b	4.09 E-04
Xylenes ^b	2.85 E-04
Propylene 	2.58 E-03
1,3-Butadiene ^{b,c}	<3.91 E-05
Formaldehyde ^b	1.18 E-03
Acetaldehyde ^b	7.67 E-04
Acrolein ^b	<9.25 E-05
Polycyclic aromatic hydrocarbons (PAH)	
Naphthalene ^b	8.48 E-05
Acenaphthylene	<5.06 E-06
Acenaphthene	<1.42 E-06
Fluorene	2.92 E-05
Phenanthrene	2.94 E-05
Anthracene	1.87 E-06
Fluoranthene	7.61 E-06
Pyrene	4.78 E-06
Benzo(a)anthracene	1.68 E-06
Chrysene	3.53 E-07
Benzo(b)fluoranthene	<9.91 E-08
Benzo(k)fluoranthene	<1.55 E-07
Benzo(a)pyrene	<1.88 E-07
Indeno(1,2,3-cd)pyrene	<3.75 E-07
Dibenz(a,h)anthracene	<5.83 E-07
Benzo(g,h,i)perylene	<4.89 E-07
TOTAL PAH	1.68 E-04

^a Based on the uncontrolled levels of 2 diesel engines from References 6-7. Source Classification Codes 2-02-001-02, 2-03-001-01. To convert from lb/MMBtu to ng/J, multiply by 430.

^b Hazardous air pollutant listed in the *Clean Air Act*.

^c Based on data from 1 engine.

Table 3.3-3. EFFECT OF VARIOUS EMISSION CONTROL TECHNOLOGIES
ON DIESEL ENGINES^a

Technology	Affected Parameter	
	Increase	Decrease
Fuel modifications		
Sulfur content increase	PM, wear	
Aromatic content increase	PM, NO _x	
Cetane number		PM, NO _x
10% and 90% boiling point		PM
Fuel additives		PM, NO _x
Water/Fuel emulsions		NO _x
Engine modifications		
Injection timing retard	PM, BSFC	NO _x , power
Fuel injection pressure	PM, NO _x	
Injection rate control		NO _x , PM
Rapid spill nozzles		PM
Electronic timing & metering		NO _x , PM
Injector nozzle geometry		PM
Combustion chamber modifications		NO _x , PM
Turbocharging	PM, power	NO _x
Charge cooling		NO _x
Exhaust gas recirculation	PM, power, wear	NO _x
Oil consumption control		PM, wear
Exhaust after-treatment		
Particulate traps		PM
Selective catalytic reduction		NO _x
Oxidation catalysts		TOC, CO, PM

^a Reference 8. PM = particulate matter. BSFC = brake-specific fuel consumption.

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**Final Technical Support Document (TSD)
for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS
Docket ID No. EPA-HQ-OAR-2015-0500**

**Assessment of Non-EGU NO_x Emission Controls, Cost of
Controls, and Time for Compliance Final TSD**

U.S. Environmental Protection Agency
Office of Air and Radiation
August 2016

1 Introduction/Purpose

The purpose of this Technical Support Document (TSD) is to discuss the currently available information on emissions and control measures for sources of NO_x other than electric generating units (EGUs). This information provides more detail about why EGUs are the focus of the final rulemaking, namely the uncertainty that exists regarding whether significant aggregate NO_x mitigation is achievable from non-EGU point sources by the 2017 ozone season, and the fact that the limited available information points to an apparent scarcity of non-EGU reductions that could be accomplished in this timeframe.

Notwithstanding these conclusions as regards the 2017 ozone season, the EPA continues to assess the role of NO_x emissions from non-EGU sources to downwind nonattainment problems.

This TSD begins by briefly discussing the non-EGU emissions inventories used in the proposed and final Cross-State Air Pollution Rule (CSAPR) Update analyses, both for the 2011 base year and 2017 future baseline assessed for this rule. The TSD then presents an evaluation of whether non-EGU emissions can be reduced in a cost-effective manner for particular categories. Then, it assesses the available NO_x emission reductions from such categories and presents the category-by-category emissions reduction potential. This assessment considers and presents the annualized costs per ton of these reductions, with a focus on technologies that achieve cost-effective reductions within a range of costs similar to that evaluated for EGUs. The TSD then presents estimates of the time required to install and implement the control measures, both for comparison to the 2017 compliance timeframe, and for discussion of installation time should such measures be required in the future. It should be noted that no changes to these data or estimates have been made for this final TSD compared to the draft version of this TSD provided in the docket for the proposed rule. Finally, the TSD presents a summary of comments received on the proposed rule TSD, along with responses as appropriate.

For the reasons stated in the preamble, the data and discussion in this TSD are intended to focus on the eastern states that are included in the CSAPR Update rule. Information inclusive of western states¹ is presented where available and appropriate.

¹ For the purpose of this action, the western United States (or the West) consists of the 11 western contiguous states of Arizona, California, Colorado, Idaho, Montana, New Mexico, Nevada, Oregon, Utah, Washington, and Wyoming, and the eastern U.S. (or East) consists of the remaining states in the contiguous U.S.

2 Background

In this section we present annual and ozone-season NO_x emission inventory totals and the relative percentages for non-EGU source categories statewide and/or nationally. This information is summary in nature and is not meant to replace other, more detailed information available from the EPA, such as the EPA's 2011v6.2 Emissions Modeling Platform TSD² as well as the Notice of Data Availability³ (NODA) and Regulatory Impact Analysis⁴ (RIA) for the proposed and final rule.

Table 1 lists 2011 and 2017 projected NO_x emissions by sector, in summary form, for the 48 contiguous states of the United States (CONUS).

Table 1: 2011 Base Year and 2017 Projected NO_x Emissions by Sector (tons), for the 48 CONUS

Sector	2011 NO _x , annual	2017 NO _x , annual	2011 NO _x , ozone season	2017 NO _x , ozone season
EGU-point	2,000,000	1,500,000	942,000	689,000
NonEGU-point	1,200,000	1,200,000	515,000	502,000
Point oil and gas	500,000	410,000	213,000	172,000
Wild and prescribed fires	330,000	330,000	165,000	165,000
Nonpoint oil and gas	650,000	690,000	275,000	293,000
Residential wood combustion	34,000	35,000	3,000	3,000
Other nonpoint	760,000	730,000	204,000	211,000
Nonroad	1,600,000	1,100,000	825,000	582,000
Onroad	5,700,000	3,200,000	2,417,000	1,329,000
C3 commercial marine vessel (CMV)	130,000	130,000	58,000	58,000
Locomotive and C1/C2 CMV	1,100,000	910,000	451,000	384,000
Biogenics	1,000,000	1,000,000	630,000	630,000
TOTAL	15,000,000	11,200,000	6,698,000	5,018,000

It is clear from Table 1 that NO_x emissions are projected to remain constant or decrease for most sectors in the 48 states between 2011 and 2017, and this is true whether examining annual or ozone season (OS) tons. Emissions from the non-EGU point source sector and the other nonpoint source sector are not projected to change significantly, while emissions

² Technical Support Document (TSD), Preparation of Emissions Inventories for the Version 6.2, 2011 Emissions Modeling Platform, August 2015, available at: <https://www.epa.gov/air-emissions-modeling/2011-version-62-technical-support-document>

³ Notice of Availability of the Environmental Protection Agency's Updated Ozone Transport Modeling Data for the 2008 Ozone National Ambient Air Quality Standard (NAAQS). The official version is available in the docket for this rulemaking.

⁴ Regulatory Impact Analysis for the Proposed Cross-State Air Pollution Rule (CSAPR) for the 2008 Ozone National Ambient Air Quality Standards (NAAQS) and Regulatory Impact Analysis for the Cross-State Air Pollution Rule (CSAPR) Update for the 2008 Ozone National Ambient Air Quality Standards (NAAQS). The official versions are available in the docket for this rulemaking.

from the nonpoint oil and gas source sector are projected to grow (approximately 6%) during this time period. Based on the values in Table 1, Figures 1 and 2 show the relative contributions of the various sectors to overall NO_x emissions (left panel) in the CONUS and for the non-EGU sectors (right panel) for 2011 and 2017, respectively.

Figure 1: 2011 NO_x emissions by sector, with further non-EGU breakout (48 states)

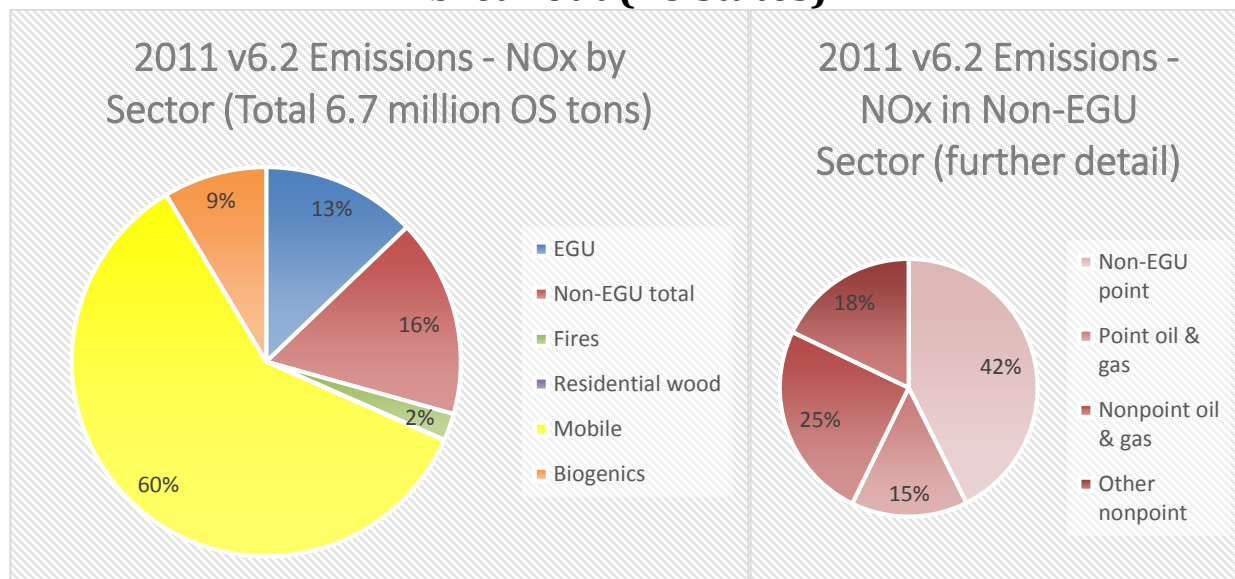


Figure 2: Projected 2017 NO_x emissions by sector, with further non-EGU breakout (48 states)

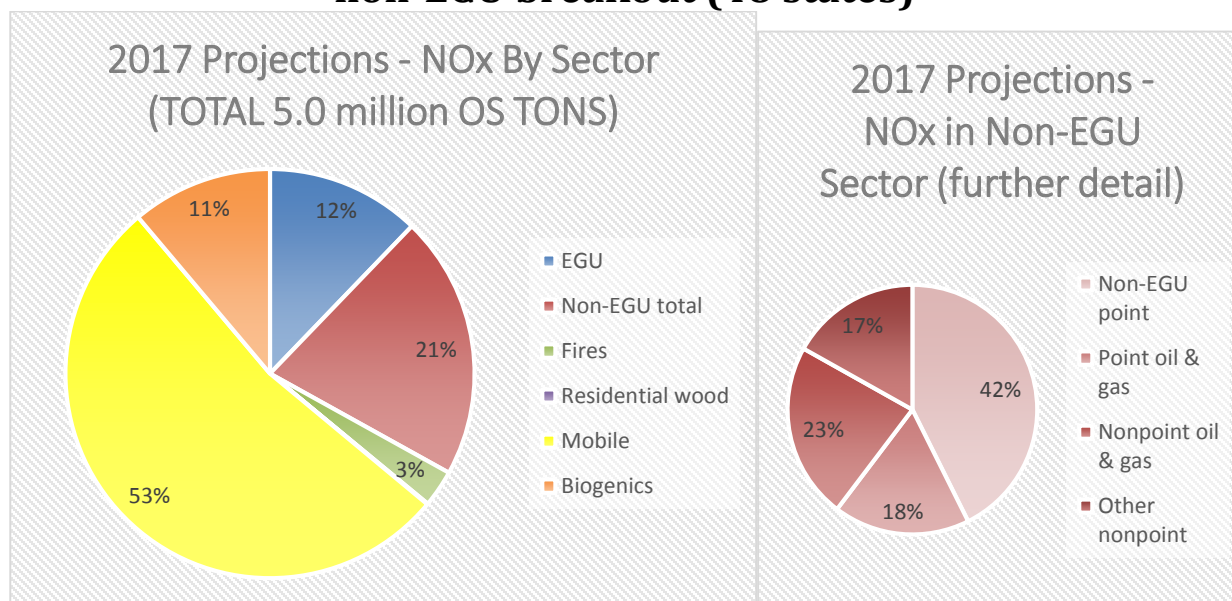


Figure 1 depicts the CONUS total ozone season NO_x emissions of 6,698,000 tons in 2011 and Figure 2 depicts the CONUS total ozone season NO_x emissions of 5,018,000 tons in 2017. In both 2011 and 2017, the mobile source sector has the largest NO_x emissions.⁵ Substantial reductions in mobile source NO_x emissions are projected to occur by 2017. Mobile source emissions are projected to decrease because of sector-specific standards related to fuels, fuel economy, pollution controls, and repair and replacement of the existing fleet. Because these reductions are already expected to occur, mobile source emission reductions are not included in this analysis of non-EGU emission reductions achievable by the 2017 ozone season.

For the purposes of preliminary analysis in this TSD, “non-EGU total” refers to four separate categories of sources: non-EGU point, point oil and gas, nonpoint oil and gas, and other nonpoint (and does not include mobile sources). The oil and gas point and nonpoint sources are separated from the remaining non-EGU point and nonpoint sources due to the magnitude of their contribution to the inventory and other aspects related to the inventory development, emissions modeling, and future year projections for that industry. The point oil and gas sources are also separated out from the other non-EGU point sources according to the North American Industry Classification System (NAICS) code specified for the various sources. Note that point oil and gas sources include a variety of types of processes, and there is overlap with the processes included in the rest of the non-EGU point inventory. More information on the emissions sectors is available in the 2011v6.2 Emissions Modeling Platform TSD.

Comparing the proportions of the total inventory for non-EGUs (Figures 1 and 2), it becomes clear that, although they are decreasing in the absolute sense, non-EGU NO_x emissions are becoming a larger share of overall ozone-season NO_x emissions (16% in 2011 compared with 21% in 2017).

Table 2 compares statewide projected total anthropogenic NO_x emissions (inclusive of all sectors listed in Table 1 with the exception of fires and biogenics) for the 2017 ozone season to non-EGU NO_x emissions for the 2017 ozone season for each of the 48 contiguous United States. Totals are given for the 48 contiguous United States (the 37 eastern states plus the District of Columbia that are addressed in the rule are highlighted below in blue). Non-EGU sources in this table are broken down into two groups (non-EGU point sources, including point oil & gas sources, and other nonpoint and nonpoint oil & gas sources).

⁵ The mobile source sector comprises multiple different types of sources (onroad cars & trucks, boats, ships, trains, construction equipment, mining equipment, tractors, etc.).

Table 2: Projected Total Anthropogenic Ozone-Season NO_x Emissions vs. Projected Non-EGU Source Group NO_x Emissions, 2017 Projections, Tons⁶

State	Total Anthropogenic	Non-EGU Point + Oil & Gas Point	% Anthro	Oil & Gas Nonpoint+ Other Nonpoint	% Anthro	Oil & Gas Point + Oil & Gas Nonpoint	% Anthro
Alabama	88,805	22,187	25	7,952	9	7,442	8
Arizona	71,906	5,015	7	2,310	3	612	1
Arkansas	69,737	13,400	19	5,308	8	9,164	13
California	236,322	29,342	12	20,220	9	3,105	1
Colorado	90,756	19,594	22	16,899	19	27,284	30
Connecticut	17,672	1,105	6	2,626	15	98	1
Delaware	7,786	628	8	615	8	0	0
District of Columbia	2,252	212	9	312	14	0	0
Florida	177,514	16,293	9	7,543	4	1,112	1
Georgia	103,536	18,816	18	4,559	4	1,495	1
Idaho	27,893	3,752	13	1,989	7	503	2
Illinois	148,178	24,668	17	15,409	10	9,424	6
Indiana	139,133	27,222	20	6,864	5	5,931	4
Iowa	70,467	7,888	11	3,861	5	153	0
Kansas	79,939	6,968	9	12,619	16	10,697	13
Kentucky	106,830	11,456	11	11,905	11	12,251	11
Louisiana	173,330	45,506	26	30,160	17	31,503	18
Maine	17,576	4,639	26	809	5	26	0
Maryland	46,029	6,213	13	3,508	8	522	1
Massachusetts	35,369	4,144	12	4,807	14	105	0
Michigan	131,486	21,867	17	12,245	9	9,398	7
Minnesota	89,328	15,541	17	6,414	7	46	0
Mississippi	54,832	11,684	21	2,122	4	6,557	12
Missouri	101,035	9,238	9	3,594	4	122	0
Montana	38,504	2,948	8	3,630	9	3,390	9
Nebraska	70,005	3,884	6	1,163	2	467	1
Nevada	28,192	4,018	14	1,003	4	115	0
New Hampshire	8,932	680	8	1,028	12	0	0
New Jersey	52,743	4,544	9	5,506	10	173	0
New Mexico	65,263	10,559	16	19,940	31	27,759	43
New York	109,910	13,738	12	14,624	13	904	1
North Carolina	98,064	15,711	16	3,657	4	1,203	1
North Dakota	74,118	4,047	5	18,125	24	19,185	26
Ohio	160,110	21,280	13	11,617	7	2,906	2
Oklahoma	131,763	32,203	24	33,178	25	51,257	39
Oregon	40,507	6,130	15	4,348	11	365	1

⁶ EGUs are not provided a separate breakout in Table 2 since state-level emissions are presented in the Preparation of Emissions Inventories for the Version 6.3, 2011 Emissions Modeling Platform TSD and other TSDs for the proposed and final rules.

State	Total Anthropogenic	Non-EGU Point + Oil & Gas Point	% Anthro	Oil & Gas Nonpoint+ Other Nonpoint	% Anthro	Oil & Gas Point + Oil & Gas Nonpoint	% Anthro
Pennsylvania	174,664	23,735	14	33,508	19	26,713	15
Rhode Island	5,845	544	9	1,370	23	12	0
South Carolina	55,897	10,144	18	3,980	7	348	1
South Dakota	22,192	1,241	6	432	2	75	0
Tennessee	85,759	13,494	16	5,846	7	1,922	2
Texas	467,245	95,671	20	115,180	25	145,285	31
Tribal Data	26,717	3,799	14	0	0	3,700	14
Utah	66,486	8,004	12	9,781	15	9,349	14
Vermont	5,473	163	3	937	17	0	0
Virginia	87,754	14,039	16	7,318	8	4,775	5
Washington	75,833	8,666	11	1,150	2	164	0
West Virginia	64,839	9,678	15	12,642	19	16,723	26
Wisconsin	75,047	11,181	15	5,351	7	178	0
Wyoming	68,864	26,488	38	4,018	6	10,905	16
<i>Eastern States</i>	<i>3,411,193</i>	<i>545,649</i>	<i>16</i>	<i>418,692</i>	<i>12</i>	<i>378,171</i>	<i>11</i>
<i>US Total</i>	<i>4,248,436</i>	<i>673,964</i>	<i>16</i>	<i>503,980</i>	<i>12</i>	<i>465,421</i>	<i>11</i>

Table 2 indicates that, in the projected 2017 inventory, non-EGU sources comprising non-EGU point and point oil and gas sources are estimated to make up 16% of anthropogenic NOx emissions in the 48 contiguous United States. In individual states, the percentage of anthropogenic emissions contributed by these two non-EGUs categories range from 3% to 26% (eastern states) and from 7% to 38% (western states).

We also note that in the projected 2017 inventory, non-EGU sources comprising nonpoint oil & gas and other nonpoint sources are estimated to make up 12% of anthropogenic NOx emissions in the entire continental U.S. In individual states, the percentage of anthropogenic emissions contributed by these non-EGUs ranges from 2% to 25% (eastern states) and from 4% to 31% (western states).

The EPA's preliminary analysis indicates that NOx emissions from oil and gas sources (inclusive of emissions from the point oil and gas and nonpoint oil and gas sectors) comprise an average of 11% of the total ozone season NOx emissions inventory. For some states, this percentage increases up to 43%, with oil and gas emissions exceeding non-EGU point totals in a number of states. The key sources of NOx emissions in the oil and gas sector are from the combustion of fossil fuel (primarily drilling rigs, internal combustion (IC) engines and pipeline compressors) and flares. Please refer to the EPA's 2011v6.2 Emissions Modeling Platform TSD for more information on emissions from these sectors.

3 Preliminary Analysis

For the purposes of the proposed rule, the EPA performed a preliminary analysis to characterize whether there are non-EGU source groups with a substantial amount of available cost-effective NO_x reductions achievable by the 2017 ozone season. The EPA received no comments that would substantively change this analysis, therefore there was no need to repeat this preliminary analysis for the final CSAPR Update rule.

3.1 Methodology

The EPA's preliminary analysis of potential non-EGU NO_x emission reductions was performed using the Control Strategy Tool (CoST). CoST is the software tool the EPA uses to estimate the emission reductions and costs associated with future-year control strategies, and then to generate emission inventories that result from the control strategies applied. CoST tracks information about control measures, their costs, and the types of emissions sources to which they apply. The purpose of CoST is to support national- and regional-scale multi-pollutant analyses, primarily for Regulatory Impact Analyses (RIAs) of the National Ambient Air Quality Standards (NAAQS). CoST is also a component of the Emissions Modeling Framework (EMF) that was used to generate the 2017 non-EGU emissions presented above and in the Emissions Modeling Platform TSD for the proposed CSAPR Update rule. Further discussion and documentation of CoST is available on the EPA's website at <http://www.epa.gov/ttnecas1/cost.htm>.

Appendices to this TSD discuss recommendations for updates to CoST, including corrections for inapplicable controls, sources already controlled by state rules, sources with permit emissions limits or that have clearly identified controls in place, and sources subject to future NO_x emission limits. Appendix A discusses contractor RTI International's work to review estimates for lean burn internal combustion (IC) engines, glass manufacturing, ammonia reformers, and gas turbines.⁷ Appendix B discusses contractor SRA International's work on a variety of other categories including many of the others evaluated in this TSD.⁸

EPA has prepared a set of data called the Control Measure Data Base (CMDB) that is used as an important input to CoST. This data includes all control measures utilized by the tool for control strategy analysis. It should be noted that most of the NO_x measures included in this report are currently in the Control Measure Data Base used by CoST, and generally do not reflect the updates suggested in these contractor reports. Obstacles to full incorporation of the recommended changes include availability of accurate costs for these measures, and to have cost equations rather than average cost/ton to estimate costs. Control efficiencies are readily available for measures, but costs, particularly those that can be estimated using equations that consider source size or capacity, often are not. In addition, the Pennsylvania

⁷ "Update of NO_x Control Measure Data in the CoST Control Measure Database for Four Industrial Source Categories: Ammonia Reformers, NonEGU Combustion Turbines, Glass Manufacturing, and Lean Burn Reciprocating Internal Combustion Engines," Revised Draft Report, RTI International, 2014.

⁸ "Review of CoST Model Emission Reduction Estimates," SRA International, 2014; "Summary of State NO_x Regulations for Selected Stationary Sources," SRA International, 2014.

Department of Environmental Protection's Additional RACT Requirements for Major Sources of NOx and VOCs rule,⁹ which was recently finalized, is not included in these contractor reports. The EPA will consider whether or not to incorporate these recommendations for changes or additions to the NOx controls for non-EGUs to support NOx control efforts for future rules and other efforts. The EPA will also consider updates to reflect state emission control requirements (i.e., Pennsylvania's RACT rule). Nonetheless, the information from these reports helped inform our assessment in terms of uncertainty surrounding non-EGU emission reduction potential. Further details on the CMDB can be found on the CoST web site shown above.

For the purpose of identifying a list of non-EGU NOx source groups with controls available, the EPA ran CoST for non-EGU point sources for the 37 eastern U.S. with NOx emissions of greater than 25 tons/year in 2017. The analysis using CoST was a basis for the review of NOx control measures for non-EGUs undertaken by two different contractors for EPA. Through a contractual agreement with EPA, SRA International and RTI International provided reports within which CoST examined a number of source categories of non-EGUs with annualized control costs up to \$10,000 per ton (in 2011 dollars). These reports are included in the Appendices of this TSD. CoST selected particular control technologies based on application of a least-cost criterion for control measures applied as part of the control strategy. Other NOx control measures are available for some of these categories, but on average, annualized costs for these measures were at higher cost.

3.2 Uncertainties and Limitations

The EPA acknowledges several important limitations of the non-EGU cost analysis included in this TSD, which include the following:

Boundary of the cost analysis: In this cost analysis we include only the impacts to the regulated industry, such as the costs for purchase, installation, operation, and maintenance of control equipment over the lifetime of the equipment. Recordkeeping, reporting, testing and monitoring costs are not included. Additional profit or income may be generated by industries supplying the regulated industry, especially for control equipment manufacturers, distributors, or service providers. These types of secondary impacts are not included in this cost analysis.

Cost and effectiveness of control measures: Our application of control measures reflect nationwide average retrofit factors and equipment life. We do not account for regional or local variation in capital and annual cost items such as energy, labor, materials, and others. Our estimates of control measure costs may over- or under-estimate the costs depending on how the difficulty of actual retrofitting and equipment life compares with our control assumptions. In addition, our estimates of control efficiencies for control measures included in our analysis assume that the control devices are properly installed and maintained. There is also variability in scale of application that is difficult to reflect for small area sources of emissions.

⁹ Available at: <http://www.pabulletin.com/secure/data/vol46/46-17/694.html>

Discount (interest) rate: Because we obtain control cost data from many sources, we are not always able to obtain consistent data across original data sources. If disaggregated control cost data are not available (i.e., where capital, equipment life value, and operation and maintenance [O&M] costs are not shown separately), the EPA assumes that the estimated control costs are annualized using a 7 percent discount rate, which is the discount (interest) rate used in accordance with OMB guidance in Circular A-4. In general, we have some disaggregated data available for non-EGU point source controls. In addition, while these interest rates are consistent with OMB guidance, the actual interest rates may vary regionally or locally.

Accuracy of control costs: We estimate that there is an accuracy range of +/- 30 percent for non-EGU point source control costs. This level of accuracy is described in the EPA Air Pollution Control Cost Manual, which is a basis for the estimation of non-EGU control cost estimates included in this TSD. This level of accuracy is consistent with either the budget or bid/tender level of cost estimation as defined by the American Association for Cost Engineering (AACE) International. In addition, the accuracy of costs is also influenced by the availability of data underlying the cost estimates for individual control measures. For some control measures, we recognize that there is limited data available to generate robust cost estimates. This is reflected in the derivation of costs for some of the non-EGU NO_x control measures discussed in Appendix A for this TSD.

3.3 CoST Results

The results of the CoST analysis are displayed in Table 3. In Table 3, we display the source groups selected by CoST, the Source Classification Codes (SCCs) included in those groups¹⁰, the least-cost control technology for a given source group (selected by CoST), the current estimate (in dollars per ton, using 2011 dollars) of the annualized cost per ton NO_x reduced of the control technology, the current estimate of the time necessary to install the selected control technology (not including permitting time), the estimated ozone season emissions in the East from the non-EGU source group in 2017 in the absence of the installation of the selected controls, and the estimated potential ozone season reductions in the East from the non-EGU source group in 2017 assuming the CoST selected controls could be fully installed and operational prior to the 2017 ozone season (which as discussed in more detail later, is not the case for many of the categories examined). Note that CoST does not account for installation time or time required for the permitting process. Instead it provides information on the control measures applicable to sources in the inventory, along with the cost of installation and operation and maintenance of the selected measures.

¹⁰ The CoST results do not indicate applicability of the recommended control technology to all sources in the source group but only to the specific SCCs for which control technologies are applicable. For example, for the cement kilns source group, Biosolid Injection Technology (BSI) is applicable only for the types of cement kilns covered by the listed SCCs.

Table 3: CoST Results: Non-EGU Source Groups with NOx Reductions

Non-EGU Source Group	SCCs	Control Technology Recommended by CoST	Current estimate of NOx \$/ton, CoST (2011 \$)	Time to install¹¹ ¹²(excluding permitting, reporting preparation, programmatic and administrative considerations¹³)	2017¹⁴ NOx Emissions (37 States + DC), OS tons, CoST	2017 Potential Reductions¹⁵ (37 States + DC), OS tons, CoST
Cement Kilns	30500622 (preheater kiln), 30500623 (preheater/precalciner); 39000201 (kiln/dryer); 39000288 (kiln in process coal)	Biosolid Injection Technology (BSI)	\$410	Uncertain	24,760	4,207

¹¹ Time to install is not an output of CoST, but are rather estimates determined by the EPA based on research from a variety of sources. See, “Typical Installation Timelines for NOx Emissions Control Technologies on Industrial Sources,” Institute of Clean Air Companies, December 2006 (all sources except Cement Kilns and RICE (Reciprocating Internal Combustion Engines)), “Cement Kilns Technical Support Document for the NOx FIP,” EPA, January 2001 (cement kilns), and “Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry,” Innovative Environmental Solutions Inc., July 2014 (prepared for the INGAA Foundation).

¹² In general, for control retrofits to non-EGU sectors, it appears that the full sector-wide compliance time is uncertain, but is longer than the installation time shown above for a typical unit. We have insufficient information on capacity and experience within the OEM suppliers and major engineering firms supply chain to offer conclusions on their availability to execute the project work for non-EGU sectors.

¹³ Non-EGUs of any type – boiler or turbine – that are not currently required to monitor and report in accordance with 40 CFR Part 75 and/or not currently participating in the CSAPR program will require additional time relative to EGUs that are currently equipped with Part 75 monitoring and reporting and/or participating in the current CSAPR program. Installation of NOx monitors for the reporting of NOx mass requires the construction of platforms, CEM shelters, procurement of equipment, certification testing, and electronic data reporting programming of a data handling system. These added timing considerations for infrastructure on the non-EGU sources combined with the additional programmatic adoption measures necessary make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources.

¹⁴ Emissions and potential reductions for Gas Turbines (\$163/ton grouping), Cement Kiln/Dryer (Bituminous Coal) (\$942/ton grouping), Coal Cleaning – Thermal Dryer (2), Spreader Stokers, Petroleum Refinery Process Heaters, Incinerators, Boilers & Process Heaters, Gas-Fired Process Heaters, Coal Boilers, By-Product Coke Manufacturing, ICI Boilers – Residual Oil, Ammonia Production, Glass Manufacturing, ICI Boilers, Iron & Steel - In-Process Combustion - Bituminous Coal, Industrial Processes Miscellaneous, Catalytic Cracking, Process Heaters, & Coke Ovens, Petroleum Refinery Gas-Fired Process Heaters, Glass Manufacturing – Pressed, Glass Manufacturing – Container, Petroleum Refinery Gas-Fired Process Heaters, and RICE source groups were calculated for 2018, however they are likely to be virtually identical to projections for 2017. Non-EGU source groups with projected aggregate 2017 NOx emissions below 100 OS tons are excluded from this table.

¹⁵ Potential reductions assume fully implemented controls by the start of the 2017 ozone season.

Cement Mfg (dry)	30500606 Industrial Processes, Mineral Products, Cement Manufacturing (Dry Process), Kilns	Selective Non-Catalytic Reduction (SNCR)	\$1,255	42-51 weeks	13,006	6,501
Cement Mfg (wet)	30500706 Industrial processes, mineral products, Cement Manufacturing (Wet Process), Kilns	Mid-Kiln Firing	\$73	5-7 months	7,971	2,287
Coal Cleaning – Thermal Dryer (1)	30502508 Construction Sand & Gravel, Dryer; 30501001 Industrial Processes, Mineral Products, Coal Mining, Cleaning, and Material Handling, Fluidized Bed Reactor	Low NOx Burner (LNB)	\$1,125	6-8 months	503	165
Coal Cleaning – Thermal Dryer (2)	30501001 Industrial Processes, Mineral Products, Coal Mining, Cleaning, and Material Handling, Fluidized Bed Reactor	Low NOx Burner (LNB)	\$1,640	6-8 months	154	63
Cement Kiln/Dryer (Bituminous Coal)	39000201 Industrial Processes, In-process Fuel Use, Bituminous Coal, Cement Kiln/Dryer (Bituminous Coal)	SNCR	\$942	42-51 weeks	520	260
Iron and Steel Mills - Reheating	30300934 (303015) Primary Metal Production: Steel; 30300933	Low NOx Burner (LNB) & Flue Gas Recirculation (FGR)	\$620	6-8 months	1,064	664
Steel Production	30490033 Industrial Processes, Secondary Metal Production, Fuel Fired Equipment, Natural Gas: Furnaces; 30400704 Industrial Processes, Secondary Metal Production, Steel Foundries, Heat Treating Furnace	Low NOx Burner (LNB)	\$928	6-8 months	281	141
Nitric Acid Mfg	30101301 Chemical Manufacturing, Nitric Acid, Absorber Tail Gas (Pre-1970 Facilities); 30101302 Chemical Manufacturing, Nitric Acid, Absorber Tail Gas (Post-1970 Facilities)	NSCR	\$900	6-14 weeks	1,290	724
Petroleum Refinery Process Heaters	30600106 Industrial Processes, Petroleum Industry, Process Heaters, Process Gas-fired	SCR-95%	\$940-\$1101	28-58 weeks	179	177

Gas Turbines	20200201 Natural Gas, Turbine; 20200203 Natural Gas, Turbine: Cogeneration; 20300202 Natural Gas, Turbine	Low NOx Burner (LNB)	\$163	12 months	945	793
Gas Turbines	20200201 Natural Gas, Turbine; 20200203 Natural Gas, Turbine: Cogeneration; 20300202 Natural Gas, Turbine; 20300203 Natural Gas, Turbine: Cogeneration	Low NOx Burner (LNB)	\$800	6-8 months	16,036	4,713
Natural Gas RICE Pipeline Compressors	20200202 Internal Combustion Engines, Industrial, Natural Gas, Reciprocating	Adjust Air to Fuel Ratio and Ignition Retard	\$249	Uncertain	10,099	2,958
Natural Gas RICE Miscellaneous	20100202 Internal Combustion Engines, Electric Generation, Natural Gas, Reciprocating; 20200202 Internal Combustion Engines, Industrial, Natural Gas, Reciprocating; 20200204, Internal Combustion Engines, Industrial, Natural Gas, Reciprocating: Cogeneration; 20300201, Internal Combustion Engines, Commercial/Institutional, Natural Gas, Reciprocating	Adjust Air to Fuel Ratio and Ignition Retard	\$447	Uncertain	27,600	8,085
Natural Gas RICE Pipeline Compressors, Rich Burn	20200253 Internal Combustion Engines, Industrial, Natural Gas, 4-cycle Rich Burn	NSCR	\$517	Uncertain	11,758	10,571
Natural Gas RICE Pipeline Compressors, Lean Burn / Clean Burn	20200252 Internal Combustion Engines, Industrial, Natural Gas, 2-cycle Lean Burn; 20200254 Internal Combustion Engines, Industrial, Natural Gas, 4-cycle Lean Burn; 20200255 Internal Combustion Engines, Industrial, Natural Gas, 2-cycle Clean Burn; 20200256 Internal Combustion Engines, Industrial, Natural Gas, 4-cycle Clean Burn	Low Emission Combustion (LEC)	\$649	Uncertain	47,321	41,169
Diesel / Dual Fuel RICE	20200401 Internal Combustion Engines, Industrial, Large Bore Engine, Diesel; 20200402 Internal Combustion Engines, Industrial, Large Bore Engine, Dual Fuel (Oil/Gas)	Ignition Retard	\$1,255	Uncertain	865	216

Catalytic Cracking (1)	30600201 Industrial Processes, Petroleum Industry, Catalytic Cracking Units, Fluid Catalytic Cracking Unit	Low NOx Burner (LNB) & Flue Gas Recirculation (FGR)	\$1,375	6-8 months	255	140
Spreader Stokers	10100204 External Combustion Boilers, Electric Generation, Bituminous/Subbituminous Coal, Spreader Stoker (Bituminous Coal)	SNCR	\$1,390	42-51 weeks	394	158
Petroleum Refinery Process Heaters	30600106 Industrial Processes, Petroleum Industry, Process Heaters, Process Gas-fired	SCR-95%	\$1,406-\$1,501	28-58 weeks	161	157
Incinerators	50200102, 50200103, 50200104, 50200504, 30190013, 30190014, 50300101, 50300106, 50300112, 50300113, 50300501, 50300503, 50300504, 50300599, 50100101, 50100102, 50100103, 50100506, 50100515, 50100516, 39990024 Incineration	SNCR	\$1,842	42-51 weeks	6,556	2,950
Boilers & Process Heaters	10200203, 10200217, 10300216, 10200204, 10200205, 10300207, 10300209, 10200799 External Combustion Boilers; 30190002, 30600103 Industrial Process Heaters	SCR	\$2,235	28-58 weeks	13,146	10,358
Natural Gas RICE Electric Generation	20100206 Internal Combustion Engines, Electric Generation, Natural Gas, Reciprocating; Evaporative Losses (Fuel Delivery System)	Adjust Air to Fuel Ratio and Ignition Retard	\$2,347	Uncertain	107	32
Catalytic Cracking (2)	30600201 Industrial Processes, Petroleum Industry, Catalytic Cracking Units, Fluid Catalytic Cracking Unit; 30600202 Industrial Processes, Petroleum Industry, Catalytic Cracking Units, Catalyst Handling System	Low NOx Burner (LNB) & Flue Gas Recirculation (FGR)	\$2,369	6-8 months	274	97
Gas-Fired Process Heaters (1)	30600104 Industrial Processes, Petroleum Industry, Process Heaters, Gas-fired	SCR-95%	\$2,376	28-58 weeks	211	204
Coal Boilers	10200206, 10200224, 10200225, 10300102, 10300208, 10300224, 10300225	SNCR	\$2,413	42-51 weeks	1099	495

Gas-Fired Process Heaters (2)	30600104 Industrial Processes, Petroleum Industry, Process Heaters, Gas Fired	Ultra-Low NOx Burners	\$2,419-\$2,638	6-8 months	137	64
By-Product Coke Manufacturing	30300306 Industrial Processes, Primary Metal Production, By-Product Coke Manufacturing, Oven Underfiring	SNCR	\$2,673	42-51 weeks	2,366	1,420
ICI Boilers – Residual Oil	10200401, 10200402, 10200404, 10300401, 10300402 External Combustion Boilers, Residual Oil	LNB & SNCR	\$2,850	6-8 months	991	689
Ammonia Production	30100306 Industrial Processes, Chemical Manufacturing, Ammonia Production, Primary Reformer: Natural Gas Fired	SCR	\$2,896	28-58 weeks	2,508	2,257
Glass Manufacturing - Flat	30501403 Industrial Processes, Mineral Products, Glass Manufacture, Flat Glass: Melting Furnace	OXY-Firing	\$3,097	Uncertain	9,721	7,880
ICI Boilers	10200201, 10200202, 10200212, 10300205, 10200501, 10200504, 10200601, 10200602, 10200603, 10200604, 10201401, 10300601, 10300602, 10200701, 10200704, 10200707, 10201402 External Combustion Boilers	Low NOx Burner & SCR	\$3,456	6-8 months (LNB) 28-58 weeks (SCR)	31,005	28,204
Iron & Steel - In-Process Combustion - Bituminous Coal	30300819, 30300824, 30300913, 30300914, 30301522 Industrial Processes, Primary Metal Production	SCR	\$3,705	28-58 weeks	829	746
Diesel RICE Miscellaneous	20100102 Internal Combustion Engines, Electric Generation, Distillate Oil (Diesel), Reciprocating; 20100107 Internal Combustion Engines, Electric Generation, Distillate Oil (Diesel), Reciprocating: Exhaust; 20200102 Internal Combustion Engines, Industrial, Distillate Oil (Diesel), Reciprocating; 20200106 Internal Combustion Engines, Industrial, Distillate Oil (Diesel), Reciprocating: Evaporative Losses (Fuel Storage and Delivery System);	SCR	\$3,814	28-58 weeks	1,091	869

	20200107 Internal Combustion Engines, Industrial, Distillate Oil (Diesel), Reciprocating; Exhaust; 20300101 Internal Combustion Engines, Commercial/Institutional, Distillate Oil (Diesel), Reciprocating; 20400403 Internal Combustion Engines, Engine Testing, Reciprocating Engine, Distillate Oil					
Catalytic Cracking, Process Heaters, & Coke Ovens	30600201, 30390004, 39000701, 39000702, 39000797	LNB & FGR	\$5,199	6-8 months	1,989	1,094
Petroleum Refinery Gas-Fired Process Heaters (3)	30600104 Industrial Processes, Petroleum Industry, Process Heaters, Gas-fired, 30600106 Industrial Processes, Petroleum Industry, Process Heaters, Process Gas-fired	SCR-95%	\$8,885-\$9,140	28-58 weeks	370	316
Glass Manufacturing - Pressed	30501404 Industrial Processes, Mineral Products, Glass Manufacture, Pressed and Blown Glass: Melting Furnace	OXY-Firing	\$6,356	Uncertain	1,001	851
Petroleum Refinery Gas-Fired Process Heaters (2)	30600104 Industrial Processes, Petroleum Industry, Process Heaters, Gas-fired, 30600106 Industrial Processes, Petroleum Industry, Process Heaters, Process Gas-fired	SCR-95%	\$7,533-\$8,120	28-58 weeks	362	304
Industrial Processes Miscellaneous	30600201 Industrial Processes, Petroleum Industry, Catalytic Cracking Units, Fluid Catalytic Cracking Unit; 39000701 Industrial Processes, In-process Fuel Use, Process Gas, Coke Oven or Blast Furnace	LNB & FGR	\$4,026	6-8 months	871	479
Glass Manufacturing - Container	30501402 Industrial Processes, Mineral Products, Glass Manufacture, Container Glass: Melting Furnace	OXY-Firing	\$7,481	Uncertain	3,107	2,628
Petroleum Refinery Gas-	30600104 Industrial Processes, Petroleum Industry, Process Heaters, Gas-fired; 30600106 Industrial	SCR-95%	\$5,609-\$5,884	28-58 weeks	372	338

Fired Process Heaters (1)	Processes, Petroleum Industry, Process Heaters, Process Gas-fired					
Taconite Ore Processing	30302351, 30302352, 30302359 Industrial Processes, Primary Metal Production, Taconite Ore Processing, Induration	SCR	\$6,449	28-58 weeks	1,188	991
Diesel RICE Electric Generation	20200102 Internal Combustion Engines, Electric Generation, Distillate Oil (Diesel), Reciprocating	SCR	\$1,499	28-58 weeks	778	622

3.4 Discussion of Non-EGU Source Groups

The below discussion utilizes the information in Table 3 in order to assess whether significant aggregate NOx mitigation is achievable from non-EGU sources by the 2017 ozone season.

It is clear that a number of source categories have been identified by CoST using the least-cost procedure that have the potential for non-EGU stationary source emissions reductions. There are some notable source categories that have the potential for substantial non-EGU stationary source emissions reductions below \$10,000 per ton.¹⁶ However, for the purposes of this analysis, the EPA did not further examine control options above \$3,400 per ton. This is consistent with the range we analyzed for EGUs in the proposed and final rules, and is also consistent with what the EPA has identified in previous transport rules as highly cost-effective, including the NOx SIP call.¹⁷ Again, this was done because the objective of this analysis is to characterize whether significant aggregate NOx mitigation is achievable from non-EGU sources by the 2017 ozone season, so we focused the search on categories with highly cost-effective technologies. This focus excludes several source groups with high emissions reduction potential because reductions from those source groups are not available for \$3,400 per ton or less, including: ICI boilers using SCR & LNB; Catalytic Cracking, Process Heaters, & Coke Ovens using LNB & FGR; and Pressed and Container Glass Manufacturing using OXY-Firing.

At a cost level of \$3,400 per ton or less, there are a number of source groups with substantial reduction potential. However the table also identifies several source groups whose reduction potential is not significant, and which the EPA did not weigh heavily in assessing the aggregate non-EGU NOx emission reduction potential. This is because the aggregate potential reductions from these “insignificant” source groups is small. These “insignificant” source groups comprise those source groups with many small sources, as well those containing a limited number of larger sources; for either of these types of groups, potential aggregate emission reductions are small relative to reductions available from other source categories. The EPA does not believe that small sources have significant emission reduction potential in the aggregate because most small sources emit less than 100 tons of NOx per year. (It is worth noting that small sources account for a significant percentage of the total number of non-EGU point sources. See Appendix A/B for more information on the number of sources within certain states.) The EPA therefore excludes from the focus of this analysis these insignificant source groups, namely, those with aggregate potential reductions of 1,000 tons per year or less (which represents less than 0.1 percent of the anthropogenic ozone season inventory).

The EPA will now focus on the several source groups with significant cost-effective reductions identified in Table 3. These source groups include cement kilns, two types of cement manufacturing (dry and wet), gas turbines, four separate groups of natural gas reciprocating IC engines (RICE), incinerators, boilers & process heaters, by-product coke

¹⁶ \$10,000 per ton represents the cost/ton for Best Available Control Technology (BACT) determinations, which usually do not exceed \$10,000/ton in the Eastern U.S.

¹⁷ \$3,400 per ton represents the \$2,000 per ton value (in 1990 dollars) used in the NOx SIP call, adjusted to the 2011 dollars used throughout this proposal. Adjustment of costs was made using the Chemical Engineering Plant Cost Index (CEPCI) annual values for 1990 and 2011.

manufacturing, ammonia production, and flat glass manufacturing. These source groups are listed below with their control technologies, estimated annualized control costs, and estimated installation time. These groups have been organized into 7 categories for clarity, based on either common control technologies (categories 1 through 6) or similarity of source groups (category 7).

Category 1	Control Tech.	Est. Cost	Est. Inst. Time
-Cement Mfg (dry)	SNCR	\$1,255	42-51 weeks
-Incinerators	SNCR	\$1,842	42-51 weeks
-By-Product Coke Manufacturing	SNCR	\$2,673	42-51 weeks
Category 2			
-Cement Kilns	Biosolid Injection Technology (BSI)	\$410	Uncertain
Category 3			
-Gas Turbines	Low NOx Burner (LNB)	\$800	6-8 months
Category 4			
-Cement Mfg (wet)	Mid-Kiln Firing	\$73	5-7 months
Category 5			
-Boilers & Process Heaters	SCR	\$2,235	28-58 weeks
-Ammonia Production	SCR	\$2,896	28-58 weeks
Category 6			
-Glass Manufacturing - Flat	OXY-Firing	\$3,097	Uncertain
Category 7			
-Gas RICE Pipeline Compressors	Adjust AFR and Ignition Retard	\$249	Uncertain
-Gas RICE Miscellaneous	Adjust AFR and Ignition Retard	\$447	Uncertain
-Gas RICE Pipeline Compressors, Rich Burn	NSCR	\$517	Uncertain
-Gas RICE Pipeline Compressors, Lean/Clean Burn	Low Emission Combustion (LEC)	\$649	Uncertain

The EPA makes the following observations about the potential reductions from these significant cost-effective categories.

The source groups listed in Category 1 would utilize SNCR as the recommended control technology. The time necessary to install SNCR equipment is generally well known. A typical installation timeline of 42-51 weeks is generally needed to complete a SNCR project

going from the bid evaluation through startup, which installation timeline is specific to non-EGUs. Based on this fact alone (which does not consider additional time likely necessary for permitting or installation of monitoring equipment), the ability for SNCR technology to be installed and operational in time for the 2017 ozone season seems very unlikely.

The source group listed in Category 2 contains a specific source of uncertainty in regards to biosolid injection technology (BSI). Due in large part to the lack of widespread use of this control technology, research performed by the EPA has been unable to uncover any reliable information on the time required to install the necessary BSI equipment on cement kilns. Compliance timing with regard to biosolid injection technology should therefore be considered extremely uncertain. Based on this fact alone (and aside from additional time likely necessary for permitting or installation of monitoring equipment), the ability for this technology to be installed and operational at all facilities in this category in time for the 2017 ozone season is unknown.

The source group listed in Category 3 would utilize LNB as the recommended control technology, with a necessary installation time of approximately 6-8 months. Some of the LNB combustion control technology identified for non-EGU sources reflects a different technology that may have different timing considerations than that considered for EGU boilers. For instance, LNB at non-EGU combustion turbines in this assessment refers to “dry low-NO_x burners” (DLNB) which, in addition to the usual diffusion burner, typically also include provisions to “premix” natural gas and combustion air prior to combustion. In spite of the similarity in naming, this is a different technology than the LNB technology examined and assumed for reductions at EGU boilers. Therefore, the same timing assumptions assumed and demonstrated on the EGU side are not necessarily applicable to combustion control technology for non-EGU sources. Moreover, non-EGUs of any type – boiler or turbine – that are not currently required to monitor and report in accordance with 40 CFR Part 75 will require additional time relative to EGUs that are currently equipped with Part 75 monitoring and reporting (such as those EGUs covered under federal transport rulemakings and this one). Installation of NO_x monitors for the reporting of NO_x mass requires the construction of platforms, Continuous Emissions Monitoring (CEM) shelters, procurement of equipment, certification testing, and electronic data reporting programming of a data handling system. These timing considerations on the non-EGU sources make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources.

The source group listed in Category 4 would utilize mid-kiln firing as the recommended control technology. A fairly well-known aspect is the time necessary to install this equipment; typically, 5-7 months is needed to complete a mid-kiln firing project going from the bid evaluation through startup. However, the above-discussed issues regarding monitoring and reporting of NO_x mass on non-EGU sources that currently lack such monitoring equipment make installation of controls by the 2017 timeframe of this rule less likely and more uncertain for industrial sources such as those in the cement manufacturing (wet) source group.

The source groups listed in Category 5 would utilize SCR as the recommended control technology, with an installation time of 28-58 weeks for SCR (dependent on exhaust gas flow rates; larger systems require longer installation times). Based on the installation time frame alone (which does not consider additional time likely necessary for permitting or installation of monitoring equipment), the ability for SCR technology to be installed and operational in time for the 2017 ozone season seems unlikely. In addition to this uncertainty, the above-discussed issues regarding monitoring and reporting of NO_x mass on non-EGU sources that currently lack such monitoring equipment make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources such as those in Category 5 source groups.

The source group listed in Category 6 would utilize OXY-Firing as the recommended control technology, with an uncertain necessary installation. A specific source of uncertainty with regard to the estimated installation time of this control technology is that OXY-Firing is generally installed only at the time of a furnace rebuild, which rebuilds may occur at infrequent intervals of a decade or more.¹⁸ In addition to this uncertainty, the above-discussed issues regarding monitoring and reporting of NO_x mass on non-EGU sources that currently lack such monitoring equipment make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources such as those in Category 6 source group.

Finally, the source groups listed in Category 7 are all RICE. While some of the recommended control technologies may involve installation timelines that are relatively short on a per-engine basis, there is substantial uncertainty in large-scale installation over numerous sources. References indicate that implementation of NO_x controls of any type on a large number of RICE will require significant lead time to train and develop resources to implement emission reduction projects; market demand could significantly exceed the available resource base of skilled professionals.¹⁹ Additionally, in order not to disrupt pipeline capacity, engine outages must be staggered and scheduled during periods of low system demands for those engines involved in natural gas pipelines (as is the case with 3 of the 4 RICE source groups with significant cost-effective reductions). In addition to this uncertainty, the above-discussed issues regarding monitoring and reporting of NO_x mass on non-EGU sources that currently lack such monitoring equipment make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources such as RICE.

4 Summary of Comments Received on Proposed Rule TSD

The EPA received relatively few comments on the draft Assessment of Non-EGU NO_x Emission Controls, Cost of Controls, and Time for Compliance TSD provided in the docket for this rule. None of these comments changed our conclusions reached in the draft TSD, as commenters generally agreed with the EPA's assessment with respect to the regulation of

¹⁸ See Appendix B.

¹⁹ "Availability and Limitations of NO_x Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry," Innovative Environmental Solutions Inc., July 2014.

non-EGUs in this rule. Detailed responses to these comments can be found in the response to comments document available in the docket for this final rule. A brief discussion of one comment containing data on control information is presented below.

Commenter Fuel Tech, Inc. (FTI) provided information on the installation time required for SNCR equipment, stating that “FTI has provided SNCR systems in 8-12 months (from contract award to performance guarantee certification)...”²⁰ This timeframe is largely consistent with the 42-51 week (9.7-11.7 month) timeframe estimate presented by the EPA in the draft TSD.

In addition, FTI provided information on a range of SNCR cost per ton based on installations from 2010 to 2015 on non-EGU sources, stating that “these recent examples show NO_x reduction cost effectiveness in the range of \$2,200 to \$2,900 per ton of NO_x removed on an annual basis.”²¹ FTI’s “Figure 1”²² also provided a chart of cost effectiveness (\$/ton) versus unit size (mmBTU/hr) for both annual and ozone season NO_x. A log fit of the ozone season curve shows cost effectiveness in the range of approximately \$2,000 to approximately \$6,500 per ton of ozone season NO_x removed, with installations tending to be more expensive for smaller unit sizes. Although FTI’s estimates are based on different interest rates and capital investments than our estimates, they are worthwhile to note in comparison to our stated estimate of \$1,300 to \$2,700 per ton of NO_x removed on an ozone season basis.

5 Conclusion

The above preliminary analysis performed by the EPA indicates that uncertainty exists regarding whether significant aggregate NO_x mitigation is achievable from non-EGU point sources by the 2017 ozone season. Reducing this uncertainty requires further understanding of potentially available control measures that could have annualized costs of \$3,400 per ton or less. In addition, further implementation of the recommendations in the Appendices to this TSD, the extent of which as determined by the EPA to be needed, may also reduce our uncertainty regarding the credibility of data for control measures included in future non-EGU NO_x control strategy efforts. Please note that while the information in these Appendices supports our conclusion regarding whether significant aggregate NO_x mitigation is achievable from non-EGU point sources by the 2017 ozone season, this final TSD is making no conclusions about the recommendations for further improvements.

While a number of source groups with control options were identified, the EPA did not further examine control options above \$3,400 per ton, consistent with the range analyzed for EGUs in the proposed and final rules and with what the EPA has identified in previous transport rules as highly cost-effective. A number of source groups were identified at a cost level of \$3,400 per ton or less, however the EPA believes several of these source groups may not be significant. Of the remaining source groups, a variety of factors indicated the ability for control technology to be installed and operational in time for the 2017 ozone

²⁰ EPA-HQ-OAR-2015-0500-0356, page 3.

²¹ EPA-HQ-OAR-2015-0500-0356, page 7.

²² EPA-HQ-OAR-2015-0500-0356, page 6.

season seemed unlikely, with an overarching consideration being that non-EGUs of any type that are not currently required to monitor and report in accordance with 40 CFR Part 75 will require additional time for implementation relative to EGUs that are currently equipped with Part 75 monitoring and reporting. These added timing considerations on the non-EQU sources make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources.

With all of these factors being considered, the limited available information points to an apparent scarcity of non-EQU reductions that could be accomplished by the beginning of the 2017 ozone season. As noted in the proposed and final rule, this conclusion has led the EPA to focus the final FIPs on EQU reductions. Both the proposal and the final rule acknowledge that this may not be the full remedy that is ultimately needed to eliminate an upwind state's significant contribution to nonattainment or interference with maintenance of the 2008 ozone NAAQS (or, for that matter, the 2015 ozone NAAQS) in other states. Emissions reductions from the non-EQU categories discussed above may be necessary, though on a longer timeframe than the 2017 compliance deadline being finalized in this rulemaking. The EPA intends to explore this question further in future ozone transport rulemakings.

May 2014

**Update of NO_x Control Measure Data in the
CoST Control Measure Database for Four
Industrial Source Categories:
Ammonia Reformers, NonEGU Combustion
Turbines, Glass Manufacturing, and Lean Burn
Reciprocating Internal Combustion Engines**

Final Report

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RTI Project Number 0212979.002.002



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Revised Draft Report

October 2014

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SECTION 1

INTRODUCTION

The U.S. Environmental Protection Agency (EPA) Health and Environmental Impacts Division (HEID) has developed the Control Strategy Tool (CoST) to support national- and regional-scale multipollutant air quality modeling analyses. CoST allows users to estimate the emissions reductions and costs associated with future-year emission control strategies, and then to generate emission inventories that reflect the effects of applying the control strategies. The tool uses EPA HEID's Control Measures Database (CMDB) to develop control strategies and provides a user interface to that database. The CMDB is a relational database that contains information on an extensive set of control measures for point sources, nonpoint sources, and mobile sources. Information contained in the database includes descriptions of the measures, control efficiencies for the pollutants affected, costs of control, and the types of sources or processes to which the control measures can be applied. The database includes robust cost equations to determine engineering costs for some control measures that take into account how control costs vary with respect to variables for the source such as unit size or flow rate. The database also includes simple cost factors for all source types in terms of dollars per ton of pollutant reduced that can be used to calculate the cost of the control measure if the applicable source variable data are unavailable or no equation has been developed.

This report presents the results of an effort to review and enhance the CMDB with new and/or updated NO_x control measure data for the following four industrial source categories: ammonia reformers, combustion turbines (nonEGU), glass manufacturing, and lean burn reciprocating internal combustion engines. Section 2 of this report describes the procedures used to locate more recent data than that currently in the CMDB for control measures applicable to ammonia reformers. Section 2 also identifies the source of the new data, describes any modifications to the assumptions or procedures in the referenced analyses needed to make the results consistent with results for other control measures in the database (such as operating hours for determination of total annual costs), and describes the specific recommended changes or additions to the database. Sections 3 through 5 of this report provide similar details for combustion turbines, glass manufacturing, and lean burn reciprocating internal combustion engines, respectively. Appendix A presents all of the records for ammonia reformer control measures in each of the CMDB tables showing their content after making the recommended revisions described in the report. Appendixes B through D provide comparable tables for the combustion turbine, glass manufacturing, and lean burn reciprocating internal combustion engine (RICE) source categories, respectively. Appendix E provides answers to questions on lean-burn RICE NO_x

emissions and available control measures. It should be noted that these revisions and updates will improve the accuracy and quality of NOx non-EGU control strategy and cost analyses for EPA rulemakings.

Appendix A

SECTION 2

AMMONIA REFORMERS SECTOR

The control measures database includes the following NO_x emissions control measures for ammonia reformers:

- Oxygen trim and water injection,
- Low NO_x burners and flue gas recirculation,
- Selective non-catalytic reduction (SNCR),
- Selective catalytic reduction (SCR), and
- Low NO_x burners.

In order to update the existing control measures database, a literature search was conducted using the following terms:

- reformer
- cost
- “NO_x” or “nitrogen oxide”
- “Low NO_x burner” or “LNB”
- “Flue gas recirculation” or “FGR”
- oxygen trim
- water injection
- “Selective catalytic reduction” or “SCR”
- “Selective non catalytic reduction” or “SNCR”
- emission reduction
- control efficiency

Due to the use of SCR and SNCR to control NO_x emissions and the fact that ammonia is used in the operation of SCR and SNCR, the literature search resulted in NO_x reductions on processes other than ammonia production.

In order to focus on ammonia production, a focused internet search for operating permits, BACT analyses, and NO_x controls was conducted using the 22 ammonia production facilities in the United States.

As a result of the following facts, most of the internet search results included NO_x reductions from the production of nitric acid production instead of ammonia production:

- The NO_x emissions from nitric acid production are covered by a New Source Performance Standard (NSPS) codified as Subpart G and Subpart Ga of Part 60.
- Nitric acid facilities covered by the NSPS are required to install NO_x continuous emission monitoring systems (CEMS).
- Many nitric acid facilities use SCR to control NO_x emissions.
- Many ammonia production facilities are co-located with nitric acid production facilities.

The internet search resulted in one new NO_x reduction project, which was the result of a voluntary agreement between Terra Nitrogen and the Indian Nations Council of Governments to install “ultra-low NO_x burner technology to an existing ammonia reformer [and] reduce the unit’s NO_x emissions by approximately 60% at a projected capital cost of two million dollars.” The existing ammonia reformer is located at Terra Nitrogen, L.P., Verdigris Plant in Claremore, Oklahoma.

Based on information known to EPA and collected for this report, Low NO_x burner technologies are known and demonstrated control techniques for ammonia reformers.

The following sections outline the deletions, additions, changes, and other comments recommended for the CMDB in relation to NO_x emissions from ammonia reformers.

2.1 Recommended Deletions

No deletions are recommended.

2.2 Recommended Additions

The only addition to the CMDB is to add the following reference: *Tulsa Metropolitan Area 8-Hour Ozone Flex Plan: 2008 8-O₃ Flex Program*. Prepared by Indian Nations Council of Governments (INCOG), 201 W. 5th Street, Suite 600, Tulsa, OK 74103. March 6, 2008.
<http://www.epa.gov/ozoneadvance/pdfs/Flex-Tulsa.pdf>.

This addition is shown in Appendix A as Table A-1.

2.3 Recommended Changes

Updates to costs and Efficiencies.

Changes to one record (LNB applied to large source types) are recommended to reflect the new reference dated March 6, 2008.

Using the new reference and a reference already contained in the CMDB, the following assumptions were made:

- NO_x reductions of 425 tons per year¹
- Capital cost of \$2 million¹
- Maintenance costs are 2.75% of capital costs²
- Equipment life of 10 years
- Interest rate of 7%
- Capital recovery factor of 0.1424.

The resulting annual costs are \$339,800 and the cost effectiveness is \$800 per ton of NO_x reduction (both in 2008 dollars). The capital to annual cost ratio is 5.9.

The previous entry showed a cost effectiveness of \$650 per ton of NO_x reduction (in 1990 dollars) and a capital to annual cost ratio is 5.5. The changes are included in Appendix A as Table A-2 and Table A-3. Changes are indicated by red, italic text.

Updates to Source Classification Codes.

The U.S. Environmental Protection Agency (USEPA) developed the Source Classification Code (SCC) system, which assigns an eight digit code to each emission unit based on the general criteria pollutant emission point type, the major industry group, specific industry group, and specific process unit/fuel combination. The system allows similar emission points to be grouped together for analyses.

For ammonia reformers, there are seven applicable SCCs, as shown in Table 2-1.

¹ Indian Nations Council of Governments (INCOG), 2008: Indian Nations Council of Governments (INCOG), "Tulsa Metropolitan Area 8-Hour Ozone Flex Plan: 2008 8-O3 Flex Program," March 6, 2008. Downloaded from <http://www.epa.gov/ozoneadvance/pdfs/Flex-Tulsa.pdf>.

² U.S. Environmental Protection Agency. Alternative Control Techniques Document— NO_x Emissions from Process Heaters (Revised), document EPA-453/R-93-034, dated September 1993.

Table 2-1. Applicable SCCs for the Ammonia Production Industry

SCC	SCC 1	SCC3	SCC6	SCC8
30100305	Industrial Processes	Chemical Manufacturing	Ammonia Production	Feedstock Desulfurization
30100306	Industrial Processes	Chemical Manufacturing	Ammonia Production	Primary Reformer: Natural Gas Fired
30100307	Industrial Processes	Chemical Manufacturing	Ammonia Production	Primary Reformer: Oil Fired
30100308	Industrial Processes	Chemical Manufacturing	Ammonia Production	Carbon Dioxide Regenerator
30100309	Industrial Processes	Chemical Manufacturing	Ammonia Production	Condensate Stripper
30100310	Industrial Processes	Chemical Manufacturing	Ammonia Production	Storage and Loading Tanks
30100399	Industrial Processes	Chemical Manufacturing	Ammonia Production	Other Not Classified

In an analysis of NO_x emissions for the Ozone Transport Region in 2011, four of the SCCs in Table 2-1 were identified. These SCCs are 30100306, 30100307, 30100310, and 30100399. Only SCCs 30100306 and 30100307 are associated with ammonia reformer NO_x controls in the current CMDB.

The known control techniques for ammonia reformers are typically used for point emission sources, such as stacks. Emissions from SCC 30100310 are not typically vented, so capture and control of these emissions is likely not feasible. Therefore, no changes related to SCC 30100310 are recommended for the CMDB.

For the purposes of this analysis, SCC 30100399 is assumed to include combustion emissions from gaseous fuels other than natural gas. Therefore, all control techniques that are applicable to natural gas fired ammonia reformers are assumed to also apply to SCC 30100399. Also, the cost to control NO_x emissions from gaseous fuels is assumed to be comparable to the cost to control NO_x emissions from natural gas. Therefore, the costs related to those control techniques are assumed to apply to SCC 30100399.

The applicable SCC from Table 2-1 was added to the Description field for each control technique in Table A-2 of Appendix A. SCC 30100306 was already included in the table; SCCs 30100305, 30100307, and 30100399 were added, where appropriate. Changes are indicated by red text.

2.4 Other Comments

Control measures used by ICI boilers. Review of NO_x control measures used for boilers was not included in this analysis. However, many of the SCR costs in the CMDB for natural gas fired ammonia reformers are based on SCR costs for Industrial/Commercial/Institutional (ICI) Boilers using Process Gas. No SCR costs specific to ammonia reformers were noted in the CMDB.

At a later time, it may be pertinent to review recent final ICI Boilers regulations or other sources for potential updates to the cost of SCR on ammonia reformers. The final major source NESHAP for ICI Boilers was promulgated on January 31, 2013 and the final area source NESHAP for ICI Boilers was promulgated on February 1, 2013.

Potential NO_x limits for ammonia reformers based on boiler NO_x limits. According to NO_x Reasonably Acceptable Control Technology (RACT), the states of New Jersey and New York have established emission limits for ICI Natural Gas Boilers (greater than 100 million BTU per hour) that could be applicable to natural gas ammonia reformers. These RACT limits are shown in Table 2-2.

Table 2-2. RACT NO_x Limits for ICI Natural Gas Boilers

State	Boiler Size	Limit (lb NO _x /MMBTU)	Effective Date
New Jersey ^a	>100 MMBTU	0.10	Already in effect
New York	>100 MMBTU and ≤ 250 MMBTU	0.06	7/1/14
New York	> 250 MMBTU	0.08	7/1/14

^a The limit also applies to other indirect heat exchangers.

SECTION 3

COMBUSTION TURBINES

The CMDB includes the following NO_x emissions control measures for Combustion Turbines:

- Water injection for natural gas-fired turbines (achieves 76 percent reduction)
- Steam injection for natural gas-fired turbines (achieves 80 percent reduction)
- Low NO_x Burners for natural gas-fired turbines (achieves 84 percent reduction)
- SCR on natural gas-fired turbines that also have water injection (achieves 95 percent reduction)
- SCR on natural gas-fired turbines that also have steam injection (achieves 95 percent control)
- SCR on natural gas-fired turbines that also have low NO_x burners (achieves 94 percent reduction)
- Water injection for oil-fired turbines (achieves 68 percent reduction)
- SCR on oil-fired turbines that also have water injection (achieves 90 percent reduction)
- Water injection for jet fuel-fired turbines (achieves 68 percent reduction)
- SCR on jet fuel-fired turbines that also have water injection (achieves 90 percent reduction)
- Water injection for aeroderivative turbines (achieves 40 percent reduction)

All of the cost data are in 1990 dollars, except the costs of water injection for aeroderivative turbines, which are in 2005 dollars. In addition, all of the costs are based on estimated operation for 8,000 hr/yr, except the costs of water injection for aeroderivative turbines, which are for intermittently operated units. The costs in 1990 dollars are based primarily on analyses in EPA's 1993 ACT document for NO_x Emissions from Stationary Gas Turbines (EPA, 1993). Capital and annual cost equations are provided for all of the controls except those for jet fuel-fired turbines and water injection for aeroderivative turbines.

Literature search. In order to update the existing CMDB, a literature search was conducted for articles and papers published since 2008. In addition, an internet search was conducted for BACT analysis reports and control technology reports prepared for federal and

state agencies and RPOs. The literature search did not identify any documents with cost data, but the internet search identified the documents listed in Section 3.5 of this report.

Changes to CMDB. The following sections outline the deletions, additions, and other changes recommended for the CMDB in relation to NO_x emissions from Combustion Turbines. All cost data and calculations are in an Excel Worksheet (RTI, 2014). Copies of the CMDB tables with recommended revisions to the records for combustion turbine controls are provided in Appendix B.

The coefficient of determination (R^2) is 1.0 for many of the regression equations presented in sections 3.2 and 3.3. The R^2 value is exactly 1.0 in cases where the analysis was based on only two data points; these cases are noted in the discussions for the particular control measure. In other cases, actual R^2 values greater than 0.995 have been rounded to 1.0. These high values likely are due to the fact that available data for most control measures are from a single source, and those sources may have already developed a correlation and then picked specific data points from that correlation for presentation in their documentation.

3.1 Recommended Deletions

RTI recommends deleting the record for water injection for aeroderivative turbines because the estimated costs are for combustion turbines that operate on a limited and intermittent basis (i.e., peaking EGUs). In principle, data for small EGU combustion turbines would be acceptable for estimating costs of control measures for nonEGUs. However, the limited operation of peaking units is inconsistent with the assumed operating time of about 8,000 hr/yr for all of the other nonEGU combustion turbine control measures in the database. For several SCCs that are currently associated with this control measure in the CMDB we are recommending applying other existing control measures, as discussed in Section 3.3.11 of this report.

The CMDB also currently applies several gas turbine control measures to reciprocating internal combustion engine SCCs and to gas turbine SCCs for evaporative losses from fuel storage and delivery systems. We recommend deleting these applications of the gas turbine control measures, as discussed in Section 3.3.11 and Section 5.9 of this report.

3.2 Recommended Additions

There are 3 control technique additions for emerging technologies to be added to the CMDB; these additions include:

- Catalytic Combustion; Gas Turbines—Natural Gas;

- EMx and Water Injection; Gas Turbines—Natural Gas;
- EMx and Dry Low NOx Combustion; Gas Turbines—Natural Gas.

3.2.1 Catalytic Combustion; Gas Turbines—Natural Gas (NCATCGTNG)

Catalytic combustion is a flameless process that allows fuel oxidation to occur at temperatures approximately 1800°F lower than those of conventional combustors (OSEC, 1999). Lower temperatures are desirable because NOx emissions levels are strongly correlated with temperature. One design that has been commercialized is the Xonon™ combustor (now called K-Lean™). In the Xonon combustor, a small amount of fuel is burned in a low temperature pre-combustor. Additional fuel is then mixed with the air and combustion gases from the pre-combustor and passed through a catalyst module. The catalyst promotes a flameless reaction between some of the fuel and oxygen. The gases then enter a burnout zone in which the remaining fuel burns. The maximum temperature in the system is between 2300°F and 2700°F. In addition to low NOx emissions, the catalytic combustor generates very little CO emissions. (Peltier, 2003; CARB, 2004; Leposky, 2004; Kawasaki, 2010; Quackenbush, 2012)

Since 1999 at least six Xonon combustors have been installed; all are 1.4 MW units (CARB, 2004; Kawasaki, 2010; Quackenbush, 2012). Testing of four of the operating Xonon combustors has shown NOx emissions less than 3 parts per million by volume on a dry basis (ppmvd) at 15% oxygen, and permit limits range from 3 ppmvd to 20 ppmvd at 15% oxygen (CARB, 2004; Quackenbush, 2012). Several companies have conducted research into developing larger catalytic combustors and other types of designs, but no information was found indicating that such units have been commercialized (CARB, 2004; Leposky, 2004; Cybulski, 2006).

Although one type of catalytic combustor has been commercialized, we recommend considering catalytic combustion as an emerging technology in the CMDB because so few units are in operation, and they are all only one size. In addition, as of 1999, issues with catalytic combustors include the need for the air-fuel mixture to have completely uniform temperature, composition, and velocity profile to assure effective use of all the catalyst and to prevent damage to the substrate from high temperatures. Also the catalyst durability is uncertain (OSEC, 1999).

The recommended costs are based on costs presented in a report by Onsite Sycom Energy Corporation (OSEC, 1999). The only change we made to the OSEC costs was to calculate capital recovery using an interest rate of 7 percent instead of 10 percent; this change makes the capital recovery costs consistent with guidance in Circular A-4 from the Office of Management and Budget. Table 3-1 summarizes the recommended cost effectiveness and capital to annual cost ratios for implementing the catalytic combustion NOx control technology. With an outlet

concentration of 3 ppmvd, catalytic combustion achieves an average reduction of 98 percent relative to uncontrolled conventional diffusion combustion.

Table 3-1. Summary of Cost Effectiveness and Supporting Data for Catalytic Combustion

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		Outlet Concentration, ppmvd	Cost Effectiveness, \$/ton NOx	Capital to Annual Cost Ratio
		Avg. ppmvd	tpy			
Small (5.2)	1999	150	<365	3	920	1.7
Small (26.3)	1999	130	>365	3	670	1.2
Large (170)	1999	210	>365	3	370	0.7

Based on regression of the data in the analysis, the best fit trend lines are represented by the following equations for the uncontrolled scenario:

$$\text{Total capital investment (1999 dollars)} = 20668 \times (\text{MMBtu/hr})^{0.57} \quad (R^2=1.0)$$

$$\text{Total annual cost (1999 dollars)} = 4254.2 \times (\text{MMBtu/hr})^{0.82} \quad (R^2=1.0)$$

For all but the smallest turbines, the incremental cost of catalytic combustors relative to conventional combustors is less than the incremental cost of DLN combustion versus conventional combustors. Thus, there are no incremental capital costs for catalytic combustion relative to conventional combustion. However, there are incremental annual costs because the cost of catalyst replacement is high. A best fit equation for incremental catalytic combustion total annual costs relative to a RACT baseline of DLN combustion is:

$$\text{Total annual cost (1999 dollars)} = 743.22 \times (\text{MMBtu/hr}) + 54105 \quad (R^2=1.0)$$

3.2.2 EMx and Water Injection; Gas Turbines—Natural Gas (NEMXWGTNG)

Like SCR, EMxTM (formerly called SCONOXTM) is a post-combustion catalytic NOx reduction technology. EMx uses a precious metal catalyst and a NOx absorption/regeneration process to convert CO and NOx to CO₂, H₂O, and N₂. NOx reacts with the potassium carbonate absorbent coating the surface of the oxidation catalyst in the EMx reactor, forming potassium nitrites and nitrates that are deposited onto the catalyst surface. Each segment, or “can,” within the reactor becomes saturated with potassium nitrites and nitrates over time and must be desorbed. Regeneration is accomplished by isolating the can via stainless steel lovers and

injecting hydrogen diluted with steam. Hydrogen is generated onsite with a small reformer that uses natural gas and steam as input streams. The hydrogen concentration of the reformed gas is typically 5 percent. Hydrogen and carbon dioxide react with the potassium nitrites and nitrates to form N₂ and H₂O and to regenerate the potassium carbonate for another absorption cycle. (OSEC, 1999; CARB, 2004)

At least 8 EMx systems at 6 facilities have been installed on combustion turbines with capacities up to 45 MW. Permit limits at most of these facilities have been set at 2.5 ppmvd for gas-fired operation. EPA has certified it as “demonstrated in practice” LAER-level technology that reduces NO_x to less than 5 ppmvd. The operating range of the catalyst is 300 to 700°F, which means the technology is not applicable for simple cycle turbines. The vendor for the technology has indicated that these systems also reduce carbon monoxide emissions to undetectable levels (essentially 100 percent reduction), reduce volatile organic compound emissions by greater than 90 percent, and reduce fine particulate matter emissions by 30 percent (EmeraChem, 2004). Test data documenting these reductions are not available. For the purposes of the CMDB database, we recommend that this control measure be listed as an emerging technology (rather than known) because its use has been limited to only a few small turbines.

The recommended costs for EMx in the combined EMx/water injection control measure are based on costs presented in a 2008 cost estimate prepared by EmeraChem Power for the Bay Area Air Quality Management District (ECP, 2008). For the purposes of developing 2008 cost inputs for the CMDB, we made the following changes to the data and assumptions used in the ECP analysis:

- Increased the indirect cost for engineering from \$200,000 to \$255,000 for the 50 MW turbine. ECP’s documentation indicated that this cost (as well as most of the other direct installation and indirect costs) would be the same as for an SCR system on the same turbine. The reported cost of \$200,000 was inconsistent with this statement.
- Increased the contingencies cost for the 50 MW turbine from \$76,486 to \$244,101. This change makes the cost consistent with ECP’s statement that the cost for contingencies is estimated to be equal to 5 percent of the total purchased equipment cost, excluding the cost of the precious metals in the catalyst, sales taxes, and freight.
- Added a cost for the performance loss due to back pressure from the EMx system for both turbines. ECP estimated the loss to be 0.5 percent, which is consistent with the estimate in the 1993 ACT for SCR and the estimate OSEC used in a cost analysis for SCONO_x (EPA, 1993; OSEC, 1999). However, the ECP analysis did not include a corresponding dollar amount for this element.

- Changed the operating hours from 7,884 hr/yr to 8,000 hr/yr. This change also had a small effect on the annual costs for utilities.
- Added costs for natural gas to generate steam for the 50 MW turbine using the same procedures presented in the ECP analysis for the 180 MW turbine. ECP did not report the basis for the amount of steam needed for the 180 MW turbine. Therefore, we plotted the reported steam consumption versus turbine size for this unit and for two turbines identified in a CARB analysis (CARB, 2004). We calculated the quantity of steam needed for EMx on the 50 MW turbine using the regression equation from this plot. Note that the unit cost for natural gas is \$9.75/1000 scf. This was a reasonable annual average cost in 2008, but it would be much too high for an analysis in 2014.
- Deleted the credit for recovery of precious metals in the spent catalyst because the cost for replacement catalyst considers only the difference between the total purchase price minus the value of the recovered material.
- Estimated the annualized cost of replacement catalyst (both the non-precious metal substrate and the precious metal coating) using the future worth factor, whereas the cost in the ECP analysis was the purchased cost divided by the 10-year replacement interval.
- Estimated the cost of annual catalyst cleaning based on the average if data reported by CARB (CARB, 2004) plus the amounts reported by ECP. Although ECP reported a slightly higher cleaning cost for the 180 MW turbine than for the 50 MW turbine, an analysis of all the cleaning data showed no correlation with turbine size. Thus, we used the average of all reported costs for both turbines.
- Revised the indirect annual cost for administrative charges. ECP estimated that these costs are the same as for an SCR system on the same turbines. We factored the cost as 2 percent of the TCI for the applicable EMx systems, which is consistent with the approach for all control devices in the EPA Control Cost Manual. This resulted in slightly higher costs.
- Increased the indirect costs for insurance, property tax, and capital recovery for both turbines because the ECP analysis excluded the precious metal costs from the TCI used in these calculations.
- Calculated capital recovery using an interest rate of 7 percent instead of 10 percent.

The capital costs for water injection in the combined EMx/water injection control measure were estimated in 1999 dollars using the regression equation for the water injection control measure (see Section 3.3.1) and then scaled to 2008 dollars using the Chemical Engineering Plant Cost Index (CEPCI). Total annual costs for water injection were first estimated in 1999 dollars using the regression equation for the water injection control option. On average, 25 percent of these costs were estimated to be for indirect costs that are factored from

the system capital cost, and the remaining 75 percent is for direct annual costs and overhead. To estimate the total annual costs for water injection in 2008, the indirect costs were scaled from the 1999 estimate using the CEPCI, and the direct annual costs and overhead were assumed to be the same as in 1999.

Table 3-2 summarizes the recommended cost effectiveness and capital to annual cost ratios for implementing the EMx plus water injection NOx control measure. With an outlet concentration of 2 ppmvd, this control measure achieves an average reduction of 99 percent relative to uncontrolled conventional diffusion combustion.

Table 3-2. Summary of Cost Effectiveness and Supporting Data for EMx Plus Water Injection

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		EMx Outlet Concentration, ppmvd	Cost Effectiveness, \$/ton NOx	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of WI, \$/ton NOx
		Avg ppmvd	tpy				
Large (50-180)	2008	160 ^a	>365	2.0	2,760	3.1	6,810

^aUncontrolled concentrations were not reported in the referenced analysis. Thus, the value used in this analysis is an assumed average that results in the estimated 84 percent reduction for DLN combustion, as described in Section 3.3.3 of this report.

Based on regression of the data in the analysis, the best fit trend lines are represented by the following power equations for the uncontrolled scenario (the $R^2 = 1.0$ for both equations because there were only two data points in the analysis):

$$\text{Total capital investment (2008 dollars)} = 196928 \times (\text{MMBtu/hr})^{\wedge 0.68}$$

$$\text{Total annual cost (2008 dollars)} = 18747 \times (\text{MMBtu/hr})^{\wedge 0.86}$$

Best fit equations for incremental EMx costs relative to a RACT baseline of water injection are:

$$\text{Total capital investment (2008 dollars)} = 156349 \times (\text{MMBtu/hr})^{\wedge 0.68}$$

$$\text{Total annual cost (2008 dollars)} = 17252 \times (\text{MMBtu/hr})^{\wedge 0.80}$$

3.2.3 EMx and Dry Low NOx Combustion; Gas Turbines—Natural Gas (NEMXDGTNG)

Table 3-3 summarizes the recommended cost effectiveness and capital to annual cost ratios for implementing the EMx plus dry low NOx combustion control measure. With an outlet concentration of 2 ppmvd, this control measure achieves an average reduction of 99 percent relative to uncontrolled conventional diffusion combustion. For the same reasons noted in Section 3.2.2, we recommend that this control measure be listed as an emerging technology in the CMDB.

Table 3-3. Summary of Cost Effectiveness and Supporting Data for EMx Plus Dry Low NOx Combustion

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		EMx Outlet Concentration, ppmvd	Cost Effectiveness, \$/ton NOx	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of DLN, \$/ton NOx
		Avg ppmvd	tpy				
Small (4.2)	1999	134	<365	2.0	2,860	3.9	14,940
Small (23)	1999	174	>365	2.0	1,720	4.1	10,270
Large (170)	1999	210	>365	2.0	840	3.9	6,600
Large (50-180)	2008	160 ^a	>365	2.0	2,050	4.1	12,390

^aUncontrolled concentrations were not reported in the referenced analysis. Thus, the value used in this analysis is an assumed average that results in the estimated 84 percent reduction for DLN combustion, as described in Section 3.3.3 of this report.

The recommended costs for EMx in 2008 dollars for the combined EMx/dry low NOx combustion control measure are the same as in the estimate for the EMx/water injection control measure described in Section 3.2.2. The recommended costs for EMx in 1999 dollars are based on an analysis prepared by Onsite Sycom Energy Corporation (OSEC, 1999). For this analysis the only changes we made to OSEC's analysis were to reduce the operating hours from 8,400 hr/yr to 8,000 hr/yr, which slightly reduced the energy penalty and utilities costs, and we calculated the capital recovery factor using an interest rate of 7 percent instead of 10 percent. Note that the total annual costs for natural gas (or purchased steam) are considerably lower in this analysis than in the 2008 analysis because the unit cost of natural gas was considerably lower in 1999.

The recommended total capital investment and total annual cost for dry low NOx combustion in 1999 dollars for the combined EMx/dry low NOx combustion control measure are the same as in the estimate for the dry low NOx combustion control measure alone as described in Section 3.3.3. The recommended total capital investment for dry low NOx combustion in 2008

dollars was estimated in 1999 dollars using the regression equation for the water injection control measure (see Section 3.3.1) and then scaled to 2008 dollars using the CEPCI. The recommended total annual costs for dry low NO_x combustion consist of capital recovery plus the cost for parts and repair; capital recovery costs in 2008 dollars were estimated by escalating the 1999 costs using the CEPCI, and annual parts and repairs costs were assumed to be the same in 2008 as in 1999.

Based on regression of the data in both the 1999 and 2008 cost analyses, the best fit trend lines are represented by the following power equations for the uncontrolled scenario (the $R^2 = 1.0$ for the equations in 2008 dollars because there were only two data points in the analysis; R^2 for the equations in 1999 dollars round to 1.0 when only two significant figures are presented):

$$\text{Total capital investment (1999 dollars)} = 58237 \times (\text{MMBtu/hr})^{\wedge 0.78}$$

$$\text{Total annual cost (1999 dollars)} = 15004 \times (\text{MMBtu/hr})^{\wedge 0.78}$$

$$\text{Total capital investment (2008 dollars)} = 126892 \times (\text{MMBtu/hr})^{\wedge 0.74}$$

$$\text{Total annual cost (2008 dollars)} = 20041 \times (\text{MMBtu/hr})^{\wedge 0.80}$$

Best fit equations for incremental EM_x costs relative to a RACT baseline of DLN combustion are:

$$\text{Total capital investment (1999 dollars)} = 65163 \times (\text{MMBtu/hr})^{\wedge 0.72}$$

$$\text{Total annual cost (1999 dollars)} = 13702 \times (\text{MMBtu/hr})^{\wedge 0.76}$$

$$\text{Total capital investment (2008 dollars)} = 156349 \times (\text{MMBtu/hr})^{\wedge 0.68}$$

$$\text{Total annual cost (2008 dollars)} = 17252 \times (\text{MMBtu/hr})^{\wedge 0.80}$$

3.3 Recommended Changes

This section presents updated cost estimates for combustion turbine control measures that are currently in the CMDB, and it describes the basis for such changes. These changes include both more recent costs for some control measures as well as minor revisions to existing estimates for other control measures. The changes affect both cost per ton values and equations.

This section also identifies applicable SCCs for the new control measures described in Section 3.2, and it identifies additional SCCs for which the control measures in this section are applicable.

3.3.1 Water Injection; Gas Turbines—Natural Gas (NWTINGTNG)

Recommended updates to the costs for water injection are based on analyses in a report prepared by OnSite Sycom Energy Corporation for the U.S. Department of Energy (OSEC, 1999). OSEC estimated costs for some of the same small turbine model sizes as in EPA's 1993 ACT document (4 MW and 23 MW). OSEC obtained water injection equipment costs in 1999 dollars. They then estimated total capital investment and total annual costs using the same procedures as in the 1993 ACT document, and they concluded that 1999 costs for water injection were essentially the same as the 1990 costs presented in the ACT document. Because the ACT analysis included a greater number of models over a wider range of sizes, RTI recommends continuing to use the cost data from the ACT analysis in the CMDB, except the cost year should be updated from 1990 to 1999. RTI also recommends the four additional changes noted below.

Our second recommendation is to split the record for small sources into two records—one for sources with uncontrolled emissions less than 365 tpy, and the other for emissions greater than 365 tpy. The 2006 AirControlNET Documentation Report indicates that small sources are turbines with design outputs up to 34.4 MW. Four model turbines in the ACT analysis have outputs below this threshold. The two turbines with uncontrolled emissions <365 tpy have an average cost effectiveness of \$1,790/ton of NO_x. The two turbines with uncontrolled emissions >365 tpy have an average cost effectiveness of \$1,000/ton of NO_x.

Our third recommendation is to revise the control efficiency for water injection from 76 percent to 72 percent. The 76 percent control level is the average reduction for all 6 model turbines in the 1993 ACT analysis. Five of those models were guaranteed to reduce NO_x emissions to less than 42 ppmvd, while the sixth was guaranteed to meet 25 ppmvd. Although water injection may be more effective on some combustion turbines than others, 42 ppmvd is the generally accepted threshold. Thus, we think this threshold should be incorporated in the CMDB. The average reduction of the 5 models in the 1993 ACT analysis with an outlet concentration of 42 ppmvd was 72 percent.

Our fourth recommendation is to use a capital to annual cost ratio of 2.4 in the new record for small sources with uncontrolled emissions >365 tpy; this is the average value for the two turbines in the ACT analysis in this size range. (The capital to annual cost ratio for the small sources with uncontrolled emissions <365 tpy would remain at 3.1 because this is the average

value for the two turbines in this size range; it is not clear why this value was applied for all small sources in the current version of the CMDB.) The total annual costs in this calculation are based on using a 7 percent interest rate in the calculation of capital recovery, instead of the 10 percent value in the 1993 ACT. Even if capital recovery was estimated using the 10 percent interest rate, it is not clear how the 3.1 value was developed.

Our fifth recommendation is to revise the constants in the CMDB table of equations for estimating capital and annual costs. Based on regression of the data in the 1993 ACT, the best fit trend lines are represented by the following revised power equations for both uncontrolled and RACT baseline scenarios:

$$\text{Total capital investment (1999 dollars)} = 27665 \times (\text{MMBtu/hr})^{0.69} \quad (R^2=0.97)$$

$$\text{Total annual cost (1999 dollars)} = 3700.2 \times (\text{MMBtu/hr})^{0.95} \quad (R^2=0.95)$$

3.3.2 Steam Injection; Gas Turbines—Natural Gas (NSTINGTNG)

The only available information on the cost of steam injection was in the 1999 report from Onsite Sycom Energy Corporation (OSEC, 1999). OSEC discussed steam injection only in the context of large GE Frame 7F turbines (170 MW). They noted that only the first such model, operational in 1990 when the ACT analysis was being conducted, was equipped with steam injection. All subsequent units (at least through 1999) were equipped with DLN combustion technology.

Because the limited available information suggests that steam injection costs, like water injection costs, were essentially the same in 1999 as in 1990, we recommend continuing to base the steam injection costs on the results in the 1993 ACT, but update the cost year from 1990 to 1999. In addition, as for water injection, we recommend splitting the one record for small sources into two records—one for sources with uncontrolled NO_x emissions <365 tpy, and the other for uncontrolled NO_x emissions >365 tpy. This split results in average cost effectiveness values of \$1,690/ton of NO_x for the small sources with uncontrolled NO_x emissions <365 tons/yr and \$820/ton of NO_x for the small sources with uncontrolled NO_x emissions >365 tons/yr. The capital cost to annual cost ratios also are slightly less than the current values in the CMDB.

Based on regression of the data in the 1993 ACT, the best fit trend lines are represented by the following revised power equations for both uncontrolled and RACT baseline scenarios:

$$\text{Total capital investment (1999 dollars)} = 43092 \times (\text{MMBtu/hr})^{\wedge 0.82} (R^2=0.95)$$

$$\text{Total annual cost (1999 dollars)} = 7282 \times (\text{MMBtu/hr})^{\wedge 0.76} (R^2=0.96)$$

3.3.3 Dry Low NO_x Combustion; Gas Turbines—Natural Gas (NDLNCGTNG)

Dry low NO_x (DLN) combustion technology premixes air and a lean fuel mixture that significantly reduces peak flame temperature and thermal NO_x formation. In some cases, this can be accomplished by using low NO_x burners, but in other cases, the combustor design itself differs as well as the burner design. For example, the DLN combustor volume is typically twice that of a conventional combustor (OSEC, 1999). Therefore, we recommend revising the current control technology name in the CMDB from “Low NO_x Burners” to “Dry Low NO_x Combustion.” In addition, the CM abbreviation should be changed from NLNBUGTNG to NDLNCGTNG.

Recommended updates to the costs for DLN Combustion are based on analyses in a report prepared by Onsite Sycom Energy Corporation for the U.S. Department of Energy (OSEC, 1999). OSEC estimated costs for some of the six turbines with design outputs ranging from 4 MW to 169 MW.

OSEC obtained installed equipment costs and annual repair costs in 1999 dollars from three turbine manufacturers, but there are some uncertainties in the data. Although the reported tabular summary indicates the equipment costs are incremental relative to the cost of a conventional combustor, the text of the report states that the costs for 169 MW turbines are the total cost to replace a conventional combustor (which may explain why the regression equation for the capital costs is linear rather than a power function). Annual costs for parts and repair for some of the turbines were proprietary for two of the small turbines and thus could not be reported. As a result, the annual costs for those turbines are biased low. In addition, because parts and repair costs were unavailable for the 169 MW turbine, OSEC assumed these costs could be represented by the costs for the 23 MW turbine.

The only change we made to the assumptions and data reported by OSEC was to calculate capital recovery using an interest rate of 7 percent instead of 10 percent.

Table 3-4 summarizes the recommended new cost effectiveness and capital to annual cost ratios for implementing the DLN combustion NO_x control technology. In addition to changing these costs in the CMDB, we also recommend changing the control efficiency for DLN combustion applied to small sources from 68 percent to 84 percent. The 84 percent level is

currently used for large sources, and it is consistent with the efficiency for DLN combustion (or low NO_x burners) in the 1993 ACT. It appears the 68 percent entry was a data transcription error because that is the control efficiency for water injection applied to oil-fired turbines.

Table 3-4. Summary of Cost Effectiveness and Supporting Data for DLN Combustion

Turbine Output, MW	Cost Year	Uncontrolled NO _x Emissions		Outlet Concentration, ppmvd	Cost Effectiveness, \$/ton NO _x	Capital to Annual Cost Ratio
		Avg. ppmvd	tpy			
Small (4-23)	1999	152	<365	25	300	5.0
Large (170)	1999	210	>365	25	130	7.4

Based on regression of the data in both analyses, the best fit trend lines are represented by the following revised equations for both uncontrolled and RACT baseline scenarios:

$$\text{Total capital investment (1999 dollars)} = 2860.6 \times (\text{MMBtu/hr}) + 25427 \quad (R^2=1.0)$$

$$\text{Total annual cost (1999 dollars)} = 584.5 \times (\text{MMBtu/hr})^{0.96} \quad (R^2=0.95)$$

3.3.4 SCR and Water Injection; Gas Turbines—Natural Gas (NSCRWGTNG)

Recommended updates to the costs for SCR combined with water injection are based on two sets of cost analyses. One set of costs is in 1999 dollars for three turbines ranging in size from 4.2 MW to 161 MW (OSEC, 1999). The second is in 2008 dollars for two larger turbines with design outputs of 50 MW and 180 MW (ECP, 2008). For SCR, the referenced analyses estimated direct installation costs and indirect costs based on scaling from the purchased equipment costs using standard factors as in the Control Cost Manual. Annual costs were estimated for the same cost elements that were used in the SCR analysis in the 1993 ACT. Water injection costs for the two smallest turbines in the 1999 analysis were estimated as described above for the water injection control option. Water injection costs for the large turbines were not estimated in the referenced analyses.

For the purposes of developing 1999 cost inputs for the CMDB, we made the following changes to the data and assumptions used in the OSEC analysis:

- Increased the engineering cost for SCR for the 161 MW turbine from \$100,000 to \$228,865. The revised value is equal to 10 percent of the purchased equipment cost, which is consistent with the approach used for the smaller turbines. The report did not explain why \$100,000 was used instead of the factor.

- Estimated performance penalty costs and electricity costs for the blower and pumps in the ammonia injection system using operating hours of 8,000 hr/yr instead of 8,400 hr/yr.
- Calculated capital recovery for the SCR system using an interest rate of 7 percent instead of 10 percent.
- Calculated annual catalyst replacement and disposal costs using a future worth factor instead of a capital recovery factor.
- Estimated total capital investment and total annual costs for the 161 MW turbine using the regression equations for the water injection control option. (Maybe it would be better to drop the large model from this analysis and just present 1999 costs for small turbines and 2008 costs for large turbines.)

For the purposes of developing 2008 cost inputs for the CMDB, we started with the ECP analysis for SCR costs and then made the following changes to the data and assumptions:

- Calculated the performance penalty for SCR using an electricity cost of \$0.06/kwh instead of \$0.1/kwh and 8,000 hr/yr instead of 8,400 hr/yr. In addition, although it appears that the referenced analysis assumed a performance loss equal to 0.5 percent of the turbine's design output, the cited cost was significantly greater than it should be for that percentage loss, even if the cited electricity cost and operating hours were used in the calculation. We changed the cost to be consistent with the calculated amount.
- Calculated capital recovery for the SCR system using an interest rate of 7 percent instead of 10 percent.
- Estimated capital costs for water injection in 1999 dollars using the regression equation for the water injection control option, and then scaled the costs to 2008 dollars using the CEPCI.
- Estimated total annual costs for water injection following the same procedure described in Section 3.2.2 for the water injection portion of a combined water injection and EMx control measure. Thus, the total annual costs for water injection are the same in both control measures.

Table 3-5 summarizes the recommended new cost effectiveness and capital to annual cost ratios values for implementing SCR plus water injection on natural gas-fired combustion turbines. Table 3-5 also presents revised incremental costs of SCR relative to a RACT baseline of water injection for the different categories of turbines. Note that the SCR outlet NO_x level was assumed to be 2.5 ppmvd in the ECP analysis, which results in an overall control efficiency of 98 percent versus the 94 percent for the OSEC and ACT analyses.

Table 3-5. Summary of Cost Effectiveness and Supporting Data for SCR Plus Water Injection

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		SCR Outlet Concentration, ppmvd	Cost Effectiveness, \$/ton NOx	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of WI, \$/ton NOx
		Avg. ppmvd	tpy				
Small (4.2)	1999	134	<365	9	2,790	3.0	5,840
Small (22.7)	1999	174	>365	9	1,370	2.9	3,130
Large (161)	1999	210	>365	9	1,070	1.5	1,690
Large (50-180)	2008	160 ^a	>365	2.5	1,830	2.7	3,170

^aUncontrolled concentrations were not reported in the referenced analysis. Thus, the value used in this analysis is an assumed average that results in the estimated 84 percent reduction for DLN combustion, as described in Section 3.3.3 of this report.

Based on regression of the data in both analyses, the revised best fit trend lines are represented by the following power equations for both uncontrolled scenarios ($R^2=1$ for the 2008 costs because the analysis was based on only two data points):

$$\text{Total capital investment (1999 dollars)} = 62962 \times (\text{MMBtu/hr})^{\wedge 0.66} (R^2=1.0)$$

$$\text{Total annual cost (1999 dollars)} = 8590 \times (\text{MMBtu/hr})^{\wedge 0.87} (R^2=0.99)$$

$$\text{Total capital investment (2008 dollars)} = 34533 \times (\text{MMBtu/hr})^{\wedge 0.85} (R^2=1.0)$$

$$\text{Total annual cost (2008 dollars)} = 6794 \times (\text{MMBtu/hr})^{\wedge 0.94} (R^2=1.0)$$

Revised best fit equations for incremental SCR costs relative to a RACT baseline of water injection are ($R^2=1$ for the 2008 costs because the analysis was based on only two data points):

$$\text{Total capital investment (1999 dollars)} = 37193 \times (\text{MMBtu/hr})^{\wedge 0.63} (R^2=1.0)$$

$$\text{Total annual cost (1999 dollars)} = 12065 \times (\text{MMBtu/hr})^{\wedge 0.64} (R^2=1.0)$$

$$\text{Total capital investment (2008 dollars)} = 10323 \times (\text{MMBtu/hr})^{\wedge 0.96} (R^2=1.0)$$

$$\text{Total annual cost (2008 dollars)} = 3106.1 \times (\text{MMBtu/hr})^{\wedge 0.94} (R^2=1.0)$$

3.3.5 SCR and Steam Injection; Gas Turbines—Natural Gas (NSCTSGTNG)

Combined costs for SCR and steam injection were not presented in any available references. Thus, costs for combined control systems were estimated in 1999 dollars for four model turbines ranging from 4 MW to 161 MW using the procedures described above for steam injection alone and for SCR as part of combined SCR and water injection control systems. Specifically, steam injection costs for each model turbine were assumed to be the same as in the 1993 ACT, consistent with the description above for steam injection control costs. Since OSEC did not estimate SCR costs for the specific turbines in this analysis, we estimated the SCR costs using the trendlines that we developed for incremental SCR costs relative to a RACT baseline of water injection. We then summed the separate SCR and steam injection costs to obtain the combined system costs.

We also estimated costs for a combined steam injection and SCR control measure in 2008 dollars. The SCR portion of the costs are the same as for SCR in the combined water injection plus SCR control measure, as described in Section 3.3.4. Total capital investment for the steam injection portion were estimated in 1999 dollars using the regression equation developed for steam injection alone, as described in Section 3.3.2. These costs were escalated to 2008 costs using the CEPCI. Total annual costs for steam injection were first estimated in 1999 dollars using the regression equation for the steam injection control option (see Section 3.3.2). On average, 40 percent of these costs were estimated to be for indirect costs that are factored from the system capital cost, and the remaining 60 percent is for direct annual costs and overhead. To estimate the total annual costs for steam injection in 2008, the indirect costs were scaled from the 1999 estimate using the CEPCI, and the direct annual costs and overhead were assumed to be the same as in 1999.

Table 3-6 summarizes the recommended new cost effectiveness and capital to annual cost ratios values for implementing SCR plus steam injection on natural gas-fired combustion turbines. Table 3-6 also presents revised incremental costs of SCR relative to a RACT baseline of steam injection for the different categories of turbines. Note that the incremental costs are slightly different from the costs in Table 3-5. The costs should be the same for a given turbine category. They differ because the two analyses examined a different number of turbines, and the sizes were not exactly the same. At a later date, the analysis could be improved by combining the SCR costs from both analyses and developing a single set of incremental SCR costs.

Table 3-6. Summary of Cost Effectiveness and Supporting Data for SCR Plus Steam Injection (SI)

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		SCR Outlet Concentration, ppmvd	Cost Effectiveness, \$/ton NOx	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of SI, \$/ton NOx
		Avg. ppmvd	tpy				
Small (4.2)	1999	155	<365	9	2,570	3.3	5,550
Small (26.8)	1999	142	>365	9	1,380	3.1	2,870
Large (83–161)	1999	300	>365	9	570	2.7	1,810
Large (50–180)	2008	160 ^a	>365	2.5	1,420	3.9	3,170

^aUncontrolled concentrations were not reported in the referenced analysis. Thus, the value used in this analysis is an assumed average that results in the estimated 84 percent reduction for DLN combustion, as described in Section 3.3.3 of this report.

Based on regression of the data in the analysis, the revised best fit trend lines are represented by the following power equations for the uncontrolled scenario ($R^2=1$ for the 2008 costs because the analysis was based on only two data points):

$$\text{Total capital investment (1999 dollars)} = 72169 \times (\text{MMBtu/hr})^{\wedge 0.66} (R^2=0.99)$$

$$\text{Total annual cost (1999 dollars)} = 17551 \times (\text{MMBtu/hr})^{\wedge 0.72} (R^2=0.98)$$

$$\text{Total capital investment (2008 dollars)} = 46492 \times (\text{MMBtu/hr})^{\wedge 0.82} (R^2=1.0)$$

$$\text{Total annual cost (2008 dollars)} = 8704 \times (\text{MMBtu/hr})^{\wedge 0.86} (R^2=1.0)$$

Revised best fit equations for incremental SCR costs relative to a RACT baseline of steam injection are assumed to be the same as noted above in the discussion of costs for SCR and water injection.

3.3.6 SCR and Dry Low NOx Combustion; Gas Turbines—Natural Gas (NSCRDGTNG)

Updated costs for combined SCR and DLN combustion control systems were estimated in 1999 dollars for all turbine sizes, 2007 dollars for small turbines, and 2008 dollars for large turbines. The 1999 costs were estimated by combining the separate costs for DLN combustion and SCR provided by Onsite Sycom Energy Systems (OSEC, 1999). The 2007 costs were estimated by combining SCR costs developed by Energy and Environmental Analysis in a report prepared for EPA with the OSEC costs for DLN combustion in 1999 dollars, escalated to 2007 dollars (EEA, 2008). Similarly, costs in 2008 dollars were estimated by combining SCR costs

developed by EmeraChem Power in an analysis for the Bay Area Air Quality Management District with escalated DLN combustion costs (ECP, 2008). The EEA analysis provided only capital costs; therefore, we estimated annual costs using the same factors provided in ECP's analysis of costs in 2008 dollars. For both the 2007 and 2008 cost estimates, DLN capital costs and capital recovery were escalated from 1999 dollars using the CEPCI, and annual parts and repairs costs were assumed to be the same in all three years.

Table 3-7 summarizes the recommended new cost effectiveness and capital to annual cost ratios values for implementing SCR plus dry low NO_x combustion on natural gas-fired combustion turbines. Table 3-7 also presents revised incremental costs of SCR relative to a RACT baseline of steam injection for the different categories of turbines. Note that the SCR outlet NO_x level was assumed to be 2.5 ppmvd in the ECP analysis, which results in an overall control efficiency of 98 percent versus the 94 percent for the OSEC analyses. We also used an outlet concentration of 2.5 ppmvd to estimate emissions to use with EEA's 2007 costs. The ECP and EEA analyses did not specify inlet NO_x emissions concentrations to the SCR; therefore, we assumed 25 ppmvd, as in other DLN analyses. We also assumed an average uncontrolled emissions level of 160 ppmvd for all models so that the overall control efficiency of the DLN combustion plus the SCR was 98 percent. Note that the incremental costs in 1999 dollars are significantly higher than those for SCR following water injection and steam injection; this is due to the inlet concentration being 25 ppmvd for this analysis and 42 ppmvd for water injection and steam injection.

Table 3-7. Summary of Cost Effectiveness and Supporting Data for SCR Plus DLN Combustion

Turbine Output, MW	Cost Year	Uncontrolled NO _x Emissions		SCR Outlet Concentration, ppmvd	Cost Effectiveness, \$/ton NO _x	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of DLN, \$/ton NO _x
		Avg. ppmvd	tpy				
Small (4.2)	1999	134	<365	9	1,800	2.9	11,900
Small (26.8)	1999	174	>365	9	990	3.6	6,320
Large (161)	1999	210	>365	9	390	4.2	3,340
Small (1–10.2)	2007	160 ^a	<365	2.5	2,910	4.3	18,900
Small (25)	2007	160 ^a	>365	2.5	1,460	3.8	7,510
Large (50–180)	2008	160 ^a	>365	2.5	1,040	4.5	5,560

^aUncontrolled concentrations were not reported in the referenced analysis. Thus, the value used in this analysis is an assumed average that results in the estimated 84 percent reduction for DLN combustion, as described in Section 3.3.3 of this report.

Based on regression of the data in each analysis, the best fit trend lines are represented by the following power equations for uncontrolled scenarios ($R^2=1$ for the 2008 costs because the analysis was based on only two data points, and note that the R^2 for the 2007 equations is not meaningful because the DLN portion of the costs are based on a regression equation instead of independent, model-specific data):

$$\text{Total capital investment (1999 dollars)} = 24854 \times (\text{MMBtu/hr})^{0.79} \quad (R^2=1.0)$$

$$\text{Total annual cost (1999 dollars)} = 12725 \times (\text{MMBtu/hr})^{0.69} \quad (R^2=1.0)$$

$$\text{Total capital investment (2007 dollars)} = 187647 \times (\text{MMBtu/hr})^{0.54} \quad (R^2=1.0)$$

$$\text{Total annual cost (2007 dollars)} = 2782 \times (\text{MMBtu/hr}) + 167494 \quad (R^2=1.0)$$

$$\text{Total capital investment (2008 dollars)} = 14790 \times (\text{MMBtu/hr})^{0.97} \quad (R^2=1.0)$$

$$\text{Total annual cost (2008 dollars)} = 5263.5 \times (\text{MMBtu/hr})^{0.90} \quad (R^2=1.0)$$

The equations to estimate incremental costs for SCR relative to a RACT baseline of dry low NO_x combustion in 1999 dollars and 2008 dollars are assumed to be the same as noted in Section 3.3.4 for incremental costs relative to a RACT baseline of water injection. Incremental costs for SCR relative to a RACT baseline of water injection in 2007 dollars are estimated using the following equations:

$$\text{Total capital investment (2007 dollars)} = 210883 \times (\text{MMBtu/hr})^{0.46} \quad (R^2=1.0)$$

$$\text{Total annual cost (2007 dollars)} = 1894 \times (\text{MMBtu/hr}) + 185570 \quad (R^2=0.99)$$

3.3.7 Water Injection; Gas Turbines—Oil (NWTINGTOL)

No new data are available on costs of water injection for oil-fired combustion turbines. However, because the water injection costs for natural gas-fired turbines were determined to be essentially the same in 1999 as in 1990, we assume the same would be true for water injection on oil-fired turbines; the costs for both types of turbines also were the same in the 1993 ACT analysis. Therefore, we recommend continuing to base costs on the results of the 1993 ACT analysis, but to update the cost year from 1990 to 1999. In addition, we changed the size of the large model in the ACT analysis from 83.3 MW to 84.7 MW because it appears the incorrect

model was used in the ACT analysis. As for the natural gas-fired turbines, we also recommend splitting the single record for small sources into two records—one for source with uncontrolled NOx emissions <365 tpy, and the other for sources with uncontrolled NOx emissions >365 tpy. The resulting cost effectiveness values for the turbines with uncontrolled NOx emissions <365 tpy and >365 tpy are \$1,630/ton of NOx and \$960/ton of NOx, respectively. The capital to annual cost ratios also change slightly.

As for other control technologies, the constants in the equations to estimate total capital costs and total annual costs differ from those in the regression analyses performed in Excel. In this case, the differences are small, but we recommend revising the constants so that all equations are developed based on the same approach. The revised equations for both the uncontrolled and RACT baseline scenarios are:

$$\text{Total capital investment (1999 dollars)} = 43255 \times (\text{MMBtu/hr})^{0.60} \quad (R^2=1.0)$$

$$\text{Total annual cost (1999 dollars)} = 6796.8 \times (\text{MMBtu/hr})^{0.80} \quad (R^2=1.0)$$

3.3.8 SCR and Water Injection; Gas Turbines—Oil (NSCRWGTNG)

SCR costs were developed in a BACT analysis for a 48 MW oil-fired combustion turbine (FMPA, 2004). Because water injection costs in 2004 dollars are not available, we calculated costs in 1999 dollars as described above for the water injection option, and then estimated costs in 2004 dollars by scaling up the 1999 capital costs (and capital recovery) using the CEPCI; other annual operating and maintenance costs were assumed to be unchanged. We used the SCR capital cost as presented in the FMPA analysis, but we made several changes to the annual costs. Although the original values may have been appropriate for the specific application evaluated by FMPA, the following changes were made to be consistent with the calculations for other controls in this analysis:

- Estimated O&M costs assuming operation for 8,000 hr/yr instead of 4,422 hr/yr.
- Excluded cost for one week of lost power generation while catalyst is being replaced, assuming that catalyst replacement can be performed during scheduled annual downtime.
- Reduced sales tax and freight cost for catalyst from 12.25 percent of the purchased cost to 8 percent of the purchased cost.
- Deleted capital recovery cost for catalyst because the catalyst is replaced annually.

- The reported annual cost for ammonia was based on a stoichiometric ratio of 1.4 (possibly because they assumed a significant generation of NO₂ relative to NO). They also applied a factor of 1.05, apparently to account for ammonia slip, as in the Control Cost Manual procedures for SCR on boilers. However, both factors should not be needed. For this analysis, we used just the 1.05 factor (also used the reported unit cost of \$750/ton of ammonia, which may have been high for 2004).
- Reduced the property tax factor from 2.75 percent of the TCI to 1 percent of the TCI.

Table 3-8 summarizes the recommended cost effectiveness and capital to annual cost ratios values for implementing SCR plus water injection on oil-fired combustion turbines. Table 3-8 also presents incremental costs of SCR relative to a RACT baseline of water injection. The 1990 costs are essentially the same as the costs currently in the CMDB, except that we recommend splitting the one record for small sources into two records.

Table 3-8. Summary of Cost Effectiveness and Supporting Data for SCR Plus Water Injection (WI) for Oil-Fired Turbines

Turbine Output, MW	Cost Year	Uncontrolled NO _x Emissions		SCR Outlet Concentration, ppmvd	Cost Effectiveness, \$/ton NO _x	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of WI, \$/ton NO _x
		Avg. ppmvd	tpy				
Small (3.3)	1990	179	<365	18	3,200	2.9	7,620
Small (26.3)	1990	211	>365	18	1,320	2.3	2,450
Large (84)	1990	228	>365	18	1,000	2.4	2,210
Large (48)	2004	200 ^a	>365	5	1,560	2.3	4,790

^aThe referenced analysis did not report an uncontrolled emissions level. The value used in this analysis is the average of the uncontrolled emissions concentrations for oil-fired model turbines in the 1993 ACT.

Based on regression of the data in the 1993 ACT, the best fit trend lines are represented by the following revised power equations for the uncontrolled scenario:

$$\text{Total capital investment (1990 dollars)} = 95837 \times (\text{MMBtu/hr})^{0.62} \quad (R^2=0.99)$$

$$\text{Total annual cost (1990 dollars)} = 25990 \times (\text{MMBtu/hr})^{0.70} \quad (R^2=1.0)$$

Revised best fit equations for incremental SCR costs relative to a RACT baseline of water injection are:

$$\text{Total capital investment (1990 dollars)} = 4744 \times (\text{MMBtu/hr}) + 368162 \quad (R^2=1.0)$$

$$\text{Total annual cost (1990 dollars)} = 1522.5 \times (\text{MMBtu/hr}) + 142643 \quad (R^2=1.0)$$

We could not develop equations for this control system in 2004 dollars because 2004 data are available for only one turbine, and thus are insufficient for this purpose.

3.3.9 Water Injection; Gas Turbines—Jet Fuel (NWTINGTJF)

The current CMDB assumes costs for jet fuel-fired turbines are the same as for oil-fired turbines. Thus, we recommend the same changes for jet fuel fired turbines as noted above for oil-fired turbines.

3.3.10 SCR and Water Injection; Gas Turbines—Jet Fuel (NSCTWGTJF)

The current CMDB assumes costs for jet fuel-fired turbines are the same as for oil-fired turbines. Thus, we recommend the same changes for jet fuel fired turbines as noted above for oil-fired turbines.

3.3.11 Applicable Control Measures for Gas Turbine SCCs

The first column in Table 3-9 lists all of the gas turbine SCCs that are associated with one or more gas turbine control measures in the CMDB table called “Table 03_SCCs.” In addition, the last seven SCCs in Table 3-9 are additional gas turbine SCCs that are not currently assigned any NO_x control measures in the CMDB. These seven SCCs, as well as many of the others at the top of Table 3-9, were identified with NO_x emissions in an EPA query of the NEI for facilities in the Ozone Transport Group Assessment Region (i.e., 37 states that are partially or completely to the east of 100°W longitude). The first 11 control measures in column headings in Table 3-9 are the gas turbine control measures that are currently in the CMDB; the last three column headings are the new control measures identified in this review and described in Section 3.2 of this report.

Each control measure that was determined to be applicable for a specific SCC is identified by either an “E” or an “N” in the cell at the intersection of the applicable SCC row and the control measure column. An “E” means the control measure is already listed in the CMDB for the particular SCC, and we concur with that designation. An “N” means the control measure is not currently linked to a particular SCC, but we recommend adding this link in the database. In some cases, we recommend applying new links between existing control measures and existing SCCs. For example, some of the SCCs are for turbines that are fired with relatively uncommon fuels such as landfill gas or gasoline. We have not located any analyses that determined the applicable controls and related costs for gas turbines fired with such fuels. In order to conduct CoST modeling analyses for these turbines, the most representative available control measures

Table 3-9. Recommended Control Measures for Gas Turbine SCCs

SCC ^a	SCC Level 1 ^b	SCC Level 2 ^c	SCC Level 3	SCC Level 4	Applicable Gas Turbine Control Measures for the SCC ^d													
					NWTINGTOL	NSCRWGTOL	NWTINGTJF	NSCRWGTJF	NWTINGTNG	NSTINGTNG	NDLNCGTNG	NSCRWGTNG	NSCRSGTNG	NSCRDGTNG	NWIGTAGT	NCATCGTNG	NEMXWGTNG	NEMXDGTTNG
20200101	ICE	Ind	Distillate Oil (Diesel)	Turbine	E	E												
20200103	ICE	Ind	Distillate Oil (Diesel)	Turbine: Cogeneration	E	E												
20200108	ICE	Ind	Distillate Oil (Diesel)	Turbine: Evap Losses	D	D												
20200109	ICE	Ind	Distillate Oil (Diesel)	Turbine: Exhaust	E	E												
20200201	ICE	Ind	Natural Gas	Turbine					E	E	E	E	E	E	D	N	N	N
20200203	ICE	Ind	Natural Gas	Turbine: Cogeneration					E	E	E	E	E	E	D	N	N	N
20200208	ICE	Ind	Natural Gas	Turbine: Evap Losses					D	D	D	D	D	D	D			
20200209	ICE	Ind	Natural Gas	Turbine: Exhaust					E	E	E	E	E	E	D	N	N	N
20200701	ICE	Ind	Process Gas	Turbine					N ^e	N ^e	N ^e	N ^e	N ^e	N ^e	D	N ^e	N ^e	N ^e
20200705	ICE	Ind	Process Gas	Refinery Gas: Turbine					N ^e	N ^e	N ^e	N ^e	N ^e	N ^e	D	N ^e	N ^e	N ^e
20200713	ICE	Ind	Process Gas	Turbine: Evap Losses											D			
20200714	ICE	Ind	Process Gas	Turbine: Exhaust					N ^e	N ^e	N ^e	N ^e	N ^e	N ^e	D	N ^e	N ^e	N ^e
20200901	ICE	Ind	Kerosene/Naphtha (Jet Fuel)	Turbine			E	E										
20200908	ICE	Ind	Kerosene/Naphtha (Jet Fuel)	Turbine: Evap Losses			D	D										
20200909	ICE	Ind	Kerosene/Naphtha (Jet Fuel)	Turbine: Exhaust			E	E										
20201008	ICE	Ind	Liquified Petroleum Gas (LPG)	Turbine: Evap Losses											D			

(continued)

Table 3-9. Recommended Control Measures for Gas Turbine SCCs (continued)

SCC ^a	SCC Level 1 ^b	SCC Level 2 ^c	SCC Level 3	SCC Level 4	Applicable Gas Turbine Control Measures for the SCC ^d														
					NWTINGTOL	NSCRWGTOL	NWTINGTJF	NSCRWGTJF	NWTINGTNG	NSTINGTNG	NDLNCGTNG	NSCRWGTNG	NSCRSGTNG	NSCRDGTNG	NWIGTAGT	NCATCGTNG	NEMXWGTNG	NEMXDGTING	
20201009	ICE	Ind	Liquified Petroleum Gas (LPG)	Turbine: Exhaust	N ^e	N ^e										D			
20201011	ICE	Ind	Liquified Petroleum Gas (LPG)	Turbine	N ^e	N ^e										D			
20201013	ICE	Ind	Liquified Petroleum Gas (LPG)	Turbine: Cogeneration	N ^e	N ^e										D			
20300102	ICE	C/I	Distillate Oil (Diesel)	Turbine	E	E													
20300108	ICE	C/I	Distillate Oil (Diesel)	Turbine: Evap Losses	D	D													
20300109	ICE	C/I	Distillate Oil (Diesel)	Turbine: Exhaust	E	E													
20300202	ICE	C/I	Natural Gas	Turbine					E	E	E	E	E	E	E	D	N	N	N
20300203	ICE	C/I	Natural Gas	Turbine: Cogeneration					E	E	E	E	E	E	E	D	N	N	N
20300208	ICE	C/I	Natural Gas	Turbine: Evap Losses					D	D	D	D	D	D	D	D			
20300209	ICE	C/I	Natural Gas	Turbine: Exhaust					E	E	E	E	E	E	E	D	N	N	N
20300701	ICE	C/I	Digester Gas	Turbine					N ^e	N ^e	N ^e	N ^e	N ^e	N ^e	N ^e	D	N ^e	N ^e	N ^e
20300708	ICE	C/I	Digester Gas	Turbine: Evap Losses												D			
20300709	ICE	C/I	Digester Gas	Turbine: Exhaust					N ^e	N ^e	N ^e	N ^e	N ^e	N ^e	N ^e	D	N ^e	N ^e	N ^e
20300801	ICE	C/I	Landfill Gas	Turbine					N ^e	N ^e	N ^e	N ^e	N ^e	N ^e	N ^e	D	N ^e	N ^e	N ^e
20300808	ICE	C/I	Landfill Gas	Turbine: Evap Losses												D			
20300809	ICE	C/I	Landfill Gas	Turbine: Exhaust					N ^e	N ^e	N ^e	N ^e	N ^e	N ^e	N ^e	D	N ^e	N ^e	N ^e
20400301	ICE	ET	Turbine	Natural Gas					N	N	N	N	N	N	N	D	N	N	N
20400304	ICE	ET	Turbine	Landfill Gas					N ^e	N ^e	N ^e	N ^e	N ^e	N ^e	N ^e	D	N ^e	N ^e	N ^e

(continued)

Table 3-9. Recommended Control Measures for Gas Turbine SCCs (continued)

SCC ^a	SCC Level 1 ^b	SCC Level 2 ^c	SCC Level 3	SCC Level 4	Applicable Gas Turbine Control Measures for the SCC ^d													
					NWNTINGTOL	NSCRWGTOL	NWNTINGTJF	NSCRWGTJF	NWNTINGTNG	NSTINGTNG	NDLNCGTNG	NSCRWGTNG	NSCRSGTNG	NSCRDGTNG	NWIGTAGT	NCATCGTNG	NEMXWGTNG	NEMXDGTNG
50100420	WD	SWD-G	Landfill Dump	Waste Gas Recovery: GT					N ^e	N ^e	N ^e	N ^e	N ^e	N ^e	D	N ^e	N ^e	N ^e
20201609	ICE	Ind	Methanol	Turbine: Exhaust	N ^e	N ^e												
20201701	ICE	Ind	Gasoline	Turbine	N ^e	N ^e												
20300901	ICE	C/I	Kerosene/Naphtha (Jet Fuel)	Turbine: JP-4			N	N										
20400302	ICE	ET	Turbine	Diesel/Kerosene	N	N												
20400303	ICE	ET	Turbine	Distillate Oil	N	N												
20400305	ICE	ET	Turbine	Kerosene/Naphtha			N	N										
20400399	ICE	ET	Turbine	Other Not Classified ^f	N ^e	N ^e												

^aSCCs in regular font are associated with one or more gas turbine control measures in the current CMDB. The SCCs in bold font represent gas turbine activities that were identified with NOx emissions in the Ozone Transport Assessment Group Region analysis but are not associated with gas turbine control measures in the current CMDB.

^bICE means “Internal Combustion Engines” and WD means “Waste Disposal.”

^cInd means “Industrial,” C/I means “Commercial/Institutional,” ET means “Engine Testing,” and SWD-G means “Solid Waste Disposal-Government.”

^dAn “E” means the control measure is currently associated with the SCC in the CMDB, and no changes are recommended. A “D” means the control measure is currently associated with the SCC, but this control measure should be deleted because it is not appropriate for the SCC. An “N” means the control measure is not currently associated with the SCC in the CMDB, but adding it is recommended.

^eThe control measure is assumed to be representative for the SCC; control cost data are unavailable for the specific fuel type for the SCC.

^fThe fuel type is unknown. For the purposes of this analysis it is assumed to be a liquid because most of the emissions identified for the engine testing SCCs in the analysis done in the Ozone Transport Assessment Group Region were from liquid fuel-fired turbines.

should be assigned. For turbines that burn miscellaneous gaseous fuels, the most representative control measures are those for natural gas-fired turbines. Similarly, for turbines that burn miscellaneous liquid fuels, the most representative available control measures are those for oil-fired turbines. The description field in the CMDB table called “Table 02_Efficiencies” could be revised to indicate that the control measures for natural gas units are assumed to be applicable for all gaseous fuel fired units, and the control measures for oil-fired units are assumed to be applicable for all liquid fuel-fired units (note that the separate control measures already in the CMDB for jet fuel-fired turbines are also based on the data for oil-fired units).

Finally, gas turbine SCCs for evaporative losses from turbine fuel storage and delivery systems are associated with NOx control measures in the current CMDB. We recommend deleting these NOx control measure/SCC records from the CMDB table called “Table 03_SCCs” because there should be no NOx emissions from the sources represented by these SCCs. These control measure/SCC combinations are identified with a “D” in the applicable cells in Table 3-9.

3.4 Example Emission Limits for NonEGU Combustion Turbines

NonEGU combustion turbines are subject to several emission regulations, including NSPS in 40 CFR part 60 and various state regulations. Example emission limits in state regulations are presented in Table 3-10.

Table 3-10. NOx Emissions Limits for NonEGU Combustion Turbines in New York

State	Type of Service	Type of Combustion Turbine Operating Cycle	Emission Limit	Effective Date
New York ^a	Any—gaseous fuel	Combined cycle	42 ppmdv (at 15% O2)	Current
		Simple cycle or regenerative cycle	50 ppmdv (at 15% O2)	Current
	Any—oil-fired	Combined cycle	65 ppmdv (at 15% O2)	Current
		Simple cycle or regenerative cycle	100 ppmdv (at 15% O2)	Current

^aThe requirements apply to combustion turbines with a maximum heat input rate greater than or equal to 10 million Btu per hour at major sources of NOx emissions. The specified limits apply until July 1, 2014; beginning on July 1, 2014, owners/operators must submit a proposal for RACT (NYCRR, 2014).

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SECTION 4

GLASS MANUFACTURING SECTOR

4.1 Introduction

The control cost database separates the glass manufacturing sector into four different types; flat glass, container glass, pressed glass, and general glass manufacturing. The CMDB listed six different control technologies for NO_x emissions which were all reviewed in 2006 and included cullet preheat, oxy-firing, electric boost, low NO_x burners, selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR). A literature and internet search was conducted to find any new control technologies for NO_x or any updates to existing controls regarding cost and efficiencies. Operating permits for some glass manufacturing plants were reviewed and control system vendors were also contacted for information. A brief summary of data from each reference reviewed is included in the spreadsheet “CoST_Glass Mfg.xlsx.”

4.2 Example NO_x Regulatory Limits

4.2.1 Wisconsin

Glass manufacturing furnace with a maximum heat input capacity equal to or greater than 50 mmBtu per hour, 2.0 pounds per ton of produced glass.¹

4.2.2 New Jersey

Commercial container glass, specialty container glass, borosilicate recipe glass, pressed glass, blown glass, and fiberglass manufacturing furnaces: 4.0 lbs/ton glass removed. Flat glass manufacturing furnaces: 9.2 lbs/ton glass removed.

4.2.3 New York

NO_x emissions are covered under NY’s case-by case RACT regulations.

4.3 Recommended Additions

The following NO_x controls are recommended additions for the glass manufacturing industry that are not currently in the control cost database, and a tabular summary of the costs is presented in Table 4-1.

- Electric Boost—Three entries for electric boost controls were in the CMDB for container, flat, and pressed glass manufacturing. A cost estimate for electric boost was found for “general” glass manufacturing (DOE, 2002), since the CMDB did not have a “general” entry for electric boost controls, an entry for “Electric Boost; Glass Manufacturing—General” was added with a new abbreviation of NELBOGMGN. The

¹ <http://dnr.wi.gov/About/NRB/2007/January/01-07-3A4.pdf>

reference provided an annualized cost of \$7,100 per ton of NOx removed based on a 250 ton of glass per day glass melting furnace operating with an emission rate of 8-lb NOx per ton glass produced and a NOx removal efficiency of 30 percent. Since the reference did not provide capital costs, the capital to annual cost ratio could not be determined, and the capital recovery factor was assumed to be the same as the electric boost entries for container, flat, and pressed glass (i.e., 0.1424, assuming equipment life of 10 years).

- Oxy-firing—Three entries for oxy-firing were in the CMDB for container, flat, and pressed glass manufacturing. Similar to electric boost controls, an updated cost estimate for oxy-firing was found for “general” glass manufacturing (DOE, 2002); since the CMDB did not have a “general” entry for oxy-firing, an entry for “OXY-Firing; Glass Manufacturing—General” was added to the CMDB with a new abbreviation of NOXYFGMGN. The reference provided an annualized cost of \$2,352 per ton of NOx removed based on a 250 ton of glass per day glass melting furnace emitting 8-lb NOx per ton glass produced and a NOx removal efficiency of 85 percent.¹ Since the capital costs were not provided the capital to annual cost ratio and the capital recovery factor were assumed to be the same as the oxy-firing entries for container, flat, and pressed glass, which all had the same values.
- Catalytic Ceramic Filter—This new control technology for NOx reduction was not previously in the database and was added for flat glass manufacturing with a new abbreviation of CATCFGMFT. A vendor was contacted for information (2013 Vendor Quote). The minimum and maximum cost per ton estimates were based on regenerative gas-fired furnace with pull rates of 600 tons per day and 490 tons per day, respectively. The estimate provided by the vendor included capital cost, annualized capital costs, and annual operational cost in 2013 dollars; it also included NOx reductions based on a 95 percent NOx efficiency.

Table 4-1. Summary of Cost Effectiveness and Supporting Data for Recommended Additions

Technology	Furnace Production Rate (ton/day)	Cost Year	NOx Removal Efficiency (%)	Cost Effectiveness, \$/ton NOx	Capital to Annual Cost Ratio
Electric Boost (general)	250	2002	30	7,100	N/A ^a
Oxy-firing General	250	2002	85	2,352	2.7
Catalytic Ceramic Filter	490	2013	95	1,045	4.6
	600	2013	95	997	4.6

^aThe ratio cannot be calculated because capital costs are not available.

4.4 Recommended Changes

Changes to the CMDDB are recommended for the following three types of control measures, which are also summarized in Table 4-2.

- Low NOx Burner General—Three entries for Low NOx burners were in the cost database for container, flat, and pressed glass manufacturing. An updated cost estimate for low NOx burners for flat glass and container glass manufacturing (EC, 2013) was found and entries NLNBUGMCN and NLNBUGMFT were updated. The reference provided capital costs and an annualized cost in euros per kilogram of NOx removed which was converted to dollars per ton of NOx. For flat glass the minimum cost per ton estimate was based on a 900 ton per day gas fired furnace, and the maximum cost per ton estimate was based on a 500 ton per day gas fired furnace. For container glass the minimum cost per ton estimate was based on 450 ton per day gas fired furnace, and the maximum cost per ton estimate was based on a 200 ton per day gas fired furnace. The capital recovery factor and the capital to annual cost ratio were also updated. We also recommend changing the equipment life for low NOx burners on flat glass furnaces from 3 years to 10 years (EC, 2013).

Additionally, equations for low NOx burners were added for entries NLNBUGMCN and NLNBUGMFT to “Table 04_Equations” of the CMDDB based on the best fit trend lines of the total capital investment and total annual cost for the facilities with the production levels described above, the best fit trend line results were as follows:

NLNBUGMCN (The correlation coefficients are high because the data are from a single source, and they may reflect data points from a correlation performed by that source)

$$\text{Total capital investment (2007 dollars)} = 30,930 \times (\text{tons/day})^{0.45} \quad (R^2 = 0.99)$$

$$\text{Total annual cost (2007 dollars)} = 9,377 \times (\text{tons/day})^{0.40} \quad (R^2 = 0.99)$$

NLNBUGMFT (The correlation coefficients are a perfect 1.0 because only two data points are available)

$$\text{Total capital investment (2007 dollars)} = 527 \times (\text{tons/day}) + 664,557 \quad (R^2 = 1.0)$$

$$\text{Total annual cost (2007 dollars)} = 132 \times (\text{tons/day}) + 150,105 \quad (R^2 = 1.0)$$

- Cullet Preheating—Two entries for cullet preheating controls were in the cost database for container and pressed glass manufacturing. An updated annualized cost per ton value and NOx efficiency for pressed and container glass entries (IT, 2002) were found and updated for entries NCLPTGMCN and NCUPHGMPD. The reference provided an annualized cost of \$5,000 per ton of NOx removed based on a 250 ton of glass per day glass melting furnace emitting 8-lb NOx per ton glass produced and a NOx removal efficiency of 5 percent.¹ Since the reference did not

¹ Annualized cost includes capital and O&M costs and is based on 2002 dollars.

provide capital costs separately, the capital to annual cost ratio and the capital recovery factor were not updated. Additionally, based on information from EPA's OECA staff, class entries for cullet preheating should be changed from "known" to "emerging" in Table 01_Summary of the CMDB because this control measure is technically feasible but has rarely been implemented.¹

- Selective Catalytic Reduction—Three entries for selective catalytic reduction were in the CMDB for container, flat, and pressed glass manufacturing. An updated cost estimate for SCR for flat glass and container glass manufacturing (EC, 2013) was found, and entries NSCRGMCN and NSCRGMFT were updated. The reference provided capital costs and an annualized cost in euros per kilogram of NO_x removed which was converted to dollars per ton of NO_x.² For flat glass the minimum and maximum cost per ton estimates were based on a 900 and 500 ton per day gas fired furnace, respectively. For container glass the minimum and maximum estimates were based on a 450 and 200 ton per day gas fired furnaces, respectively. The capital to annual cost ratio were also updated.

Equations for SCR were added for entries NSCRGMCN and NSCRGMFT to Table 4 of the CMDB based on the best fit trend lines of the total capital investment and total annual cost for the facilities with the production levels described above, the best fit trend line results were as follows:

NSCRGMCN (The correlation coefficients are high because the data are from a single source, and they may reflect data points from a correlation performed by that source)

$$\text{Total capital investment (2007 dollars)} = 79,415 \times (\text{tons/day})^{0.51} \quad (R^2 = 0.99)$$

$$\text{Total annual cost (2007 dollars)} = 643 \times (\text{tons/day}) + 135,302 \quad (R^2 = 1.0)$$

NSCRGMFT (The correlation coefficients are a perfect 1.0 because only two data points are available)

$$\text{Total capital investment (2007 dollars)} = 3681 \times (\text{tons/day}) + 1.0\text{E}+06 \quad (R^2 = 1.0)$$

$$\text{Total annual cost (2007 dollars)} = 842 \times (\text{tons/day}) + 424,930 \quad (R^2 = 1.0)$$

¹ Personal communication. Katie McClintock, US EPA/OECA, with Larry Sorrels, US EPA/OAR/OAQPS, Feb. 13, 2014.

² Conversion based on 2008 average exchange rate of 0.711. Source: <http://www.irs.gov/Individuals/International-Taxpayers/Yearly-Average-Currency-Exchange-Rates>

Table 4-2. Summary of Cost Effectiveness and Supporting Data for Recommended Additions

Technology	Furnace Production Rate (ton/day)	Cost Year	NO _x Removed (tons/year)	Cost Effectiveness, \$/ton NO _x	Capital to Annual Cost Ratio
NLNBUGMCN	200	2007	66	1,365	4.2
	450	2007	100	1,072	4.3
NLNBUGMFT	500	2007	371	574	4.2
	900	2007	611	447	4.3
NCLPTGMCN	250	2002	5%	5,000	4.5
NCUPHGMPD	250	2002	5%	5,000	4.5
NSCRGMCN	200	2007	121	2,169	4.5
	450	2007	251	1,684	4.2
NSCRGMFT	500	2007	886	957	3.4
	900	2007	1,383	855	3.7

4.5 Recommended Deletions

- Selective Non-Catalytic Reduction—Three entries for selective non-catalytic reduction were in the cost database for container, flat, and pressed glass manufacturing. Based on conversations between EPA and OECA staff, SNCR entries for glass manufacturing should be removed based on recent NSR settlements that indicate SNCR is not a technically feasible control technology for the removal of NO_x.¹

4.6 Updates to Source Classification Codes

- There are twenty applicable SCCs for glass manufacturing as shown in Table 4-3.
- In an analysis of NO_x emissions for the Ozone Transport Assessment Group Region in 2011, fourteen of the SCCs in Table 4-3 were identified. The six SCCs not included in the Ozone Transport Region are shown at the bottom of Table 4-3. Four of the SCCs, 30501401, 30501402, 30501403, and 30501404 are associated with glass manufacturing NO_x controls in the current CMDB.
- Furnaces are the primary source of NO_x emissions in the glass manufacturing industry, therefore NO_x emission control techniques are typically for point emission sources associated with furnace emissions. The four SCCs identified in the CMDB pertain to four types of melting furnaces; general, flat, container, and pressed. The

¹ Personal communication. Katie McClintock, US EPA/OECA, with Larry Sorrels, US EPA/OAR/OAQPS, Feb. 13, 2014.

remaining sixteen SCCs in Table 4-3 are not associated with furnaces. Therefore, no changes related to SCCs are recommended for the CMDB.

- For new control techniques added to the CMDB for glass manufacturing, the applicable SCC from Table 4-3 was added to the Description field for each control technique in Table 01_Summary in the CMDB (Table C-1 of Appendix C of this report). These related control measures and SCCs should also be added to “Table 03_SCCs” in the CMDB.

Table 4-3. Applicable SCCs for the Glass Manufacturing Industry

SCC Code	SCC Level One	SCC Level Two	SCC Level Three	SCC Level Four
30501401 ^a	Industrial Processes	Mineral Products	Glass Manufacture	Furnace/General**
30501402 ^a	Industrial Processes	Mineral Products	Glass Manufacture	Container Glass: Melting Furnace
30501403 ^a	Industrial Processes	Mineral Products	Glass Manufacture	Flat Glass: Melting Furnace
30501404 ^a	Industrial Processes	Mineral Products	Glass Manufacture	Pressed and Blown Glass: Melting Furnace
30501406	Industrial Processes	Mineral Products	Glass Manufacture	Container Glass: Forming/Finishing
30501407	Industrial Processes	Mineral Products	Glass Manufacture	Flat Glass: Forming/Finishing
30501408	Industrial Processes	Mineral Products	Glass Manufacture	Pressed and Blown Glass: Forming/Finishing
30501410	Industrial Processes	Mineral Products	Glass Manufacture	Raw Material Handling (All Types of Glass)
30501411	Industrial Processes	Mineral Products	Glass Manufacture	General **
30501413	Industrial Processes	Mineral Products	Glass Manufacture	Cullet: Crushing/Grinding
30501414	Industrial Processes	Mineral Products	Glass Manufacture	Ground Cullet Beading Furnace
30501416	Industrial Processes	Mineral Products	Glass Manufacture	Glass Manufacturing
30501420	Industrial Processes	Mineral Products	Glass Manufacture	Mirror Plating: General
30501499	Industrial Processes	Mineral Products	Glass Manufacture	See Comment **
SCCs Not Included in the Ozone Transport Assessment Group Region:				
30501405	Industrial Processes	Mineral Products	Glass Manufacture	Presintering
30501412	Industrial Processes	Mineral Products	Glass Manufacture	Hold Tanks **
30501415	Industrial Processes	Mineral Products	Glass Manufacture	Glass Etching with Hydrofluoric Acid Solution
30501417	Industrial Processes	Mineral Products	Glass Manufacture	Briquetting
30501418	Industrial Processes	Mineral Products	Glass Manufacture	Pelletizing
30501421	Industrial Processes	Mineral Products	Glass Manufacture	Demineralizer: General

^aDenotes SCCs included in the CMDB.

4.7 References

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Vendor Quote 2013 – Confidential Business Information

SECTION 5

LEAN BURN ENGINES

The CMDB includes the following NO_x emissions control measures for Lean Burn Engines:

- Air to fuel ratio (AFR) (achieves 20 percent reduction)
- Air to fuel ratio (AFR) and Ignition retard (IR) (achieves 30 percent reduction)
- Ignition retard (IR) (achieves 20 percent reduction)
- Low emission combustion (achieves 87 percent reduction)
- Low emissions combustion, low speed (achieves 87 percent reduction)
- Low emissions combustion, medium speed (achieves 87 percent reduction)
- Nonselective catalytic reduction (NSCR) (achieves 90 percent reduction)
- Selective catalytic reduction (SCR) (achieves 90 percent reduction)
- Selective noncatalytic reduction (SNCR) (achieves 90 percent reduction)

Based on the literature review and the new cost data identified for Lean Burn control technologies, several changes to the CMDB are recommended. No changes to existing records in CMDB are recommended. The following sections outline the additions and other comments recommended for the CMDB in relation to NO_x emissions from Lean Burn Engines.

5.1 Literature Search

In order to update the existing control measures database, a literature search was conducted for articles and papers published since 2008 (to include 2008 through August 2013) using the following terms:

- engine
- lean burn
- cost
- NO_x or “nitrogen oxides”
- scr or “selective catalytic reduction”
- turbocharge

- air/fuel ratio
- layered combustion
- high energy ignition
- high pressure fuel injection
- “low emission control” or LEC
- electronic engine control
- combustion modification
- timing
- exhaust gas recirculation
- lean NOx catalyst
- lean NOx trap
- control efficiency
- emission reduction

The literature search identified a total of 19 references, and the abstracts for these references were reviewed. Three references of potential interest were identified and two of these were obtained for review in the lean burn engine control device study.

5.2 Document Review

A brief summary of data from each reference reviewed is included in the spreadsheet “CoST_leanburn.xlsx,” in worksheet “Overall Sum—New Ref Review.” The information and data available from each reference is provided in table format, along with indication of whether the data were used or not.

There are 6 control technique additions to be added to the CMDB from 5 references.

The recommended additions include:

- Low Emission Combustion, LEC (for natural gas engines);
- Layered Combustion, LC (for 2 stroke natural gas engines);
- Layered Combustion, LC (for 2 stroke Large Bore natural gas engines);

- Air to Fuel Ratio Controller, AFRC;
- Selective Catalytic Reduction, SCR (for 4 stroke natural gas engines); and
- SCR (for diesel engines).

Recent cost data for these control techniques were available from reports dated 2001 through 2012.

The references for the added control techniques are included on the “**Table 06 References**” worksheet and are as follows:

OTC 2012. Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions. Final. October 17, 2012.

SJVAPCD 2003. RULE 4702—Internal Combustion Engines—Phase 2. Appendix B, Cost Effectiveness Analysis for Rule 4702 (Internal Combustion Engines—Phase 2). San Joaquin Valley Air Pollution Control District. July 17, 2003.
www.arb.ca.gov/pm/pmmeasures/ceffect/rules/sjvapcd_4702.pdf

CARB 2001. Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines. California Environmental Protection Agency, Air Resources Board, Stationary Source Division, Emissions Assessment Branch, Process Evaluation Section. November 2001.

EPA 2010. Alternative Control Techniques Document: Stationary Diesel Engines. March 5, 2010.

PA DEP 2013. Technical Support Document General Permit GP-5. Pennsylvania Department of Environmental Protection, Bureau of Air Quality. January 31, 2013.

5.3 Low Emission Combustion (LEC) (NLEICENG)

The costs and cost effectiveness for applying LEC to natural gas Lean Burn engines are obtained from the document *Appendix B, Cost Effectiveness Analysis for Rule 4702 (Internal Combustion Engines—Phase 2)* (SJVAPCD 2003). Information was provided on Capital costs, Annual costs, uncontrolled emissions, and reduction efficiency. The assumptions for the original reference analysis are provided in Table 5-1 for LEC along with changes in assumptions for the current analysis.

LEC are described as retrofit kits that allow engines to operate on extremely lean fuel mixtures to minimize NOx emissions. The LEC retrofit may include: (1) redesign of cylinder head and pistons to improve mixing (on smaller engines), (2) Precombustion chamber (on larger engines), lower cost, simple versions, (3) Turbocharger, (4) High energy ignition system,

Table 5-1. LEC for Natural Gas Lean Burn Engines

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: 80%	None.
Capital costs: provided for multiple models	None.
Annual Costs	
Equipment life: 10 yr	None.
Interest rate: 10%	Interest rate: 7%
Operating hours: 2000 hr/yr	None.
Emission rate, uncontrolled: 740 ppmv	Emission rate, uncontrolled: Assumed mid to upper end hp rating for each model.
Emission rate, controlled: 80% reduction	None.
Annualized equipment cost: provided for multiple model sizes	CRF: 0.1424
Annual O&M cost: assumed \$0.	None.

(5) Aftercooler, and (6) Air to fuel ratio controller. (A discussion of individual technologies is provided in Appendix B of the original reference, pp. B-1 to B-28). No detail was provided on the exact combination of combustion modifications included in the example cost analysis; some references indicate that LEC on larger engines often includes a PCC (p.B-10) (CARB 2001). LEC are known or demonstrated control techniques for lean burn engines. An 80 percent NO_x emission reduction can be achieved by LEC with little or no fuel penalty (in fact, LEC technologies are expected to decrease fuel consumption because they result in leaner burning engine, though the costs do not account for fuel consumption decrease). The original reference assumed an 80 percent reduction in the cost example.

Capital and annual costs were provided for multiple size ranges of engines. The capital costs ranged from \$14,000 to \$256,000. Costs for the 1000 to 3000 hp model were given as \$40,000 to \$256,000, and a mid-range cost of \$148,000 was assumed in the current analysis. The total annual costs ranged from \$2,000 to \$21,000 (these costs are very similar to the costs calculated in the original reference analysis). The original reference assumed there are no annual operation and maintenance costs incurred from the combustion modification technologies, and the only annual cost provided is for annualized capital costs. No emission reductions are provided in the document (however the final cost effectiveness values are provided and the reduction assumed in the original analysis can be back-calculated). In the current analysis, a hp

rating based on the middle or upper end of each size range was assumed for estimating the uncontrolled NOx emissions. An estimate of emissions was made in the current analysis. Uncontrolled NOx emissions were estimated based on an uncontrolled NOx concentration of 740 ppmv (this equates to approximately 9 g/bhp-hr), the operating hours were provided as 2000 hr/yr in the original reference, and controlled emissions were estimated based on 80 percent reduction as stated in the reference. Uncontrolled NOx emissions ranged from 1.1 to 34 tpy for the models, and the NOx reductions ranged from 0.90 to 27 tpy for the models.

The current analysis shows a cost effectiveness of \$2,200/ton of NOx reduction to \$780/ton for 2000 hr/yr operation, and the average cost effectiveness across all the models is \$1,000/ton of NOx reduction.

The cost year is not provided in the reference; assumed the cost year is the date of the cited reference, 2001\$.

Based on the cost calculations for engines of varying hp, the following equations were developed for the capital cost and annual costs for LEC on natural gas Lean Burn engines:

$$\text{Capital cost} = 16019 e^{0.0016 \times (\text{hp})}$$

$$\text{Annual cost} = 2280.8 e^{0.0016 \times (\text{hp})}$$

The R² value for these equations is 0.96. These equations should be included in the CoST database file under a new equation type.

See the cost calculations in worksheet "LEC (CARB)-2001" of the Excel file.

5.4 Layered Combustion (LC), 2 Stroke (NLCICE2SNG)

The costs and cost effectiveness for applying LC to natural gas Lean Burn engines (2 stroke) are obtained from the document *Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions* (OTC 2012). Information was provided on Capital costs; assumptions were made to determine Annual costs, uncontrolled emissions, and reduction efficiency. The assumptions for the original reference analysis are provided in Table 5-2 for LC for 2 stroke engines, along with changes in assumptions for the current analysis.

LC consists of multiple combustion modification technologies. The combustion modifications included in this example are related to (1) Air supply; (2) Fuel supply, (3) Ignition, (4) Electronic controls, and (5) Engine monitoring (a discussion of individual technologies is provided on pp. 17 to 19 for 2 stroke Lean Burn engines). No significant detail was provided on which specific combustion modification technologies were applied. In the example study, 3 of

the most representative manufacturer and models of 2 stroke Lean Burn engines used for integral compressors were selected for evaluation; these 3 engines were Cooper GMVH-10 2250 hp,

Table 5-2. LC for Natural Gas Lean Burn Engines, 2-stroke

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: Not provided.	Control efficiency: derived value is 97% (this is high)
Capital costs: based on cited ERLE 2009 project (First unit upgrade costs)	Capital costs: used average based on the provided range for each make/model engine.
Annual Costs	
Equipment life: Not provided.	Equipment life: 10 yr
Interest rate: Not provided.	Interest rate: 7%
Operating hours: Not provided.	Operating hours: 2000 hr/yr
Emission rate, uncontrolled: Not provided	Emission rate, uncontrolled: 16.8 g/bhp-hr
Emission rate, controlled: 0.5 g/bhp-hr	None.
Annualized equipment cost: Not provided.	CRF: 0.1424
Annual O&M cost: Not provided.	Annual O&M cost: \$0.

Clark TLA-6 2000 hp, and Cooper GMW-10 2500 hp (cited ERLE 2009 report “ERLE Cost Study of the Retrofit Legacy Pipeline Engines to Satisfy 0.5 g/bhp-hr NO_x”). LC are known or demonstrated control techniques for lean burn, 2 stroke engines. A NO_x emissions rate of 0.5 g/bhp-hr was achieved. The OTC 2012 document provided an estimate of the capital cost range for retrofitting technologies to achieve the outlet NO_x limit for each engine. An average cost based on the range was estimated for each engine and used in the current analysis. Details on the buildup of these costs are not provided in the OTC 2012 document. No annual costs are provided in the document. No emission reductions are provided in the document.

Based on the review of other references in this analysis, it was assumed that there are no additional annual operating costs incurred from the combustion modification technologies, except for annualized capital costs (CARB 2001). Because no emission reduction data were provided, an estimate of emissions was made in the current analysis. Uncontrolled NO_x emissions were assumed to be 16.8 g/bhp-hr (EPA 2003), controlled emissions were 0.5 g/bhp-hr as stated in the reference, and the operating hours were assumed to be 2000 hr/yr (this assumption is consistent with the LEC operating hours in the CARB 2001 document).

Uncontrolled NOx emissions for the 3 similar sized engines ranged from 74 to 93 tpy, and the NOx reductions ranged from 72 to 90 tpy.

Based on the 3 make and model engines, the average cost was estimated to be \$2,800,000 for approximately 2250 hp engines (average hp of the 3 units), and the average total annual cost was estimated to be \$390,000. The average cost effectiveness is \$4,900/ton of NOx reduction for 2000 hr/yr operation.

The cost year is not provided in the reference; we assumed the cost year is the date of the cited Cameron 2010 retrofit project, 2010\$.

See the cost calculations in worksheet "Overall Sum—New Ref Review" of the Excel file, rows 21 through 25.

5.5 Layered Combustion (LC), Large Bore, 2 Stroke, Low Speed (NLCICE2SLBNG)

The costs and cost effectiveness for applying LC to natural gas Lean Burn engines (2 stroke Large Bore) are obtained from the document *Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions* (OTC 2012). Large Bore RICE are those with large piston diameters. The larger the bore (or piston diameter), the larger the volume available for engine combustion, and hence the greater the power delivered by the engine. Information was provided on Capital costs; assumptions were made to determine Annual costs, uncontrolled emissions, and reduction efficiency. The assumptions for the original reference analysis are provided in Table 5-3 for LC for large bore 2 Stroke engines, along with changes in assumptions for the current analysis.

LC consists of multiple combustion modification technologies. The combustion modifications included (1) High pressure fuel injection; (2) Turbocharging, (3) Precombustion chamber, and (4) Cylinder head modifications (a discussion of individual technologies is provided on pp. 18 to 19 for 2 stroke Lean Burn engines). LC are known or demonstrated control techniques for lean burn, large bore, 2 stroke engines. These modifications achieved a NOx emissions rate of 0.5 g/bhp-hr. The OTC 2012 document provided ranges of capital costs for retrofitting combustion modifications for large bore 2 stroke Lean Burn engines from 200 to 11,000 hp (cited Cameron 2011 presentation "Available Emission Reduction Technology for Existing Large Bore Slow Speed Two Stroke Engines." A copy of this presentation was not found.). Details on the buildup of these costs are not provided in the OTC 2012 document. No annual costs are provided in the document. No emission reductions are provided in the document.

Based on the review of other references in this analysis, it was assumed that there are no additional annual operating costs incurred from the combustion modification technologies, except for annualized capital costs (CARB 2001). Because no emission reduction data were provided, an estimate of emissions was made in the current analysis. Uncontrolled NOx

Table 5-3. LC for Natural Gas Lean Burn Engines, Large Bore 2-stroke

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: Not provided.	Control efficiency: derived value is 97% (this is high)
Capital costs: based on cited Cameron 2010 project	None.
Annual Costs	
Equipment life: Not provided.	Equipment life: 10 yr
Interest rate: Not provided.	Interest rate: 7%
Operating hours: Not provided.	Operating hours: 2,000 hr/yr
Emission rate, uncontrolled: Not provided	Emission rate, uncontrolled: 16.8 g/bhp-hr
Emission rate, controlled: 0.5 g/bhp-hr	None.
Annualized equipment cost: Not provided.	CRF: 0.1424
Annual O&M cost: Not provided.	Annual O&M cost: \$0.

emissions were assumed to be 16.8 g/bhp-hr (EPA 2003), controlled emissions were 0.5 g/bhp-hr as stated in the reference, and the operating hours were assumed to be 2000 hr/yr (this assumption is consistent with the LEC operating hours in the CARB 2001 document). Uncontrolled NOx emissions were estimated to be 410 tpy for the larger 11,000 hp engines and were estimated to be 7.4 tpy for the smaller 200 hp engines.

For the larger 11,000 hp engines, the current analysis shows a cost effectiveness of \$1,500/ton of NOx reduction, and for the smaller 200 hp engines, the cost effectiveness is \$38,000/ton of NOx reduction.

The cost year is not provided in the reference; assumed the cost year is the date of the cited Cameron 2010 retrofit project, 2010\$.

See the cost calculations in worksheet “Overall Sum—New Ref Review” of the Excel file, rows 12 and 13.

5.6 Air to Fuel Ratio Controller (AFRC) (NAFRCICENG)

The costs and cost effectiveness for applying AFRC to natural gas Lean Burn engines are obtained from the document *Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines* (CARB 2001). Information was provided on Capital costs; assumptions were made to determine Annual costs, uncontrolled emissions, and reduction efficiency. The assumptions for the original reference analysis are provided in Table 5-4 for AFRC, along with changes in assumptions for the current analysis.

Table 5-4. AFRC for Natural Gas Lean Burn Engines

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: not provided	Control efficiency: assumed 20%
Capital costs: provided for multiple models	None.
Annual Costs	
Equipment life: 10 yr	None.
Interest rate: 10%	Interest rate: 7%
Operating hours: 2000 hr/yr	None.
Emission rate, uncontrolled: 740 ppmv	Emission rate, uncontrolled: Assumed mid to upper end hp rating for each model.
Emission rate, controlled: 80% reduction	None.
Annualized equipment cost: provided for multiple model sizes	CRF: 0.1424
Annual O&M cost: assumed \$0.	None.

AFRC are electronic engine controls that typically monitor engine parameters and atmospheric conditions to determine the correct air/fuel mixture for the operating condition, such as varying engine load or speed conditions, varying ambient conditions, or startup/shutdown conditions. (OTC 2012) (A discussion of individual technologies is provided in Appendix B of the original reference, CARB 2001, pp. B-1 to B-28). AFRC are known or demonstrated control techniques for lean burn engines. An 80 percent NO_x emission reduction can be achieved by AFRC in combination with other combustion modifications, however a fuel consumption penalty of up to 3 percent can occur due to AFRC.

Capital were provided for multiple size ranges of engines. The capital costs ranged from \$4,200 to \$6,500 per engine.

No annual costs were provided in the document. No emissions reductions were provided in the document. Based on the cost analysis for other combustion technology controls in this document, it was assumed that there are no additional annual operating costs incurred from the combustion modification technologies, except for annualized capital costs (this assumption ignores the fuel penalty issue). The total annual costs ranged from \$600 to \$930. Because no emission reductions were provided in the document, an estimate of emissions was made in the current analysis. In the current analysis, a hp rating based on the middle or upper end of each size range was assumed for estimating the uncontrolled NOx emissions. Uncontrolled NOx emissions were estimated based on an uncontrolled NOx concentration of 740 ppmv (this equates to approximately 9 g/bhp-hr), the operating hours were assumed to be 2000 hr/yr (similar to the operating hours for other control technology analyses provided in the document), and controlled emissions were estimated based on an assumption of 20 percent reduction. Uncontrolled NOx emissions ranged from 1.1 to 34 tpy for the models, and the NOx reductions ranged from 0.22 to 6.7 tpy for the models.

The current analysis shows a cost effectiveness of \$2,700/ton of NOx reduction to \$140/ton for 2000 hr/yr operation, and the average cost effectiveness across all the models is \$810/ton of NOx reduction.

The cost year is not provided in the reference; assumed the cost year is the date of the cited reference, 2001\$.

Based on the cost calculations for engines of varying hp, the following equations were developed for the capital cost and annual costs for AFRC on natural gas Lean Burn engines:

$$\text{Capital cost} = 1.3007 \times (\text{hp}) + 4354.5$$

$$\text{Annual cost} = 0.1852 \times (\text{hp}) + 619.99$$

The R² value for these equations is 0.87. These equations should be included in the CoST database file under a new equation type.

See the cost calculations in worksheet “AFRC (CARB)-2001” of the Excel file.

5.7 SCR (for 4 Stroke Natural Gas Engines) (NSCRICE4SNG)

The costs and cost effectiveness for applying SCR to natural gas engines are obtained from the document *Appendix B, Cost Effectiveness Analysis for Rule 4702 (Internal Combustion*

Engines—Phase 2) (SJVAPCD 2003). Information was provided on Capital costs, Annual costs, uncontrolled emissions, and reduction efficiency. The assumptions for the original reference analysis are provided in Table 5-5 for SCR for natural gas engines along with changes in assumptions for the current analysis. SCR is a known or demonstrated control technique for lean burn engines, although multiple references indicate that the feasibility of SCR application for lean burn engines is highly site-specific.

Table 5-5. SCR for Natural Gas Lean Burn Engines, 4-stroke.

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: 90%	None.
Capital costs: based on RACT/BARCT Determination.	None.
Annual Costs	
Equipment life: 10 years	None.
Interest rate: 10%	Interest rate: 7%
Operating hours rate 1: 2190 hr/yr (equivalent to capacity factor of 0.25)	None.
Operating hours rate 2: 6570 hr/yr (equivalent to capacity factor of 0.75)	None.
Emission rate, uncontrolled: 740 ppmv NOx	None.
Emission rate, controlled: 65 ppmv NOx	None.
Annualized equipment cost: based on RACT/BARCT Determination.	None.
Annual O&M cost: based on RACT/BARCT Determination.	None.

The installed equipment capital cost ranged from \$45,000 to \$185,000 for 50 hp engines and 1500 hp engines, respectively. The total annual costs ranged from \$27,000 for a 50 hp engine to \$140,000 for a 1500 hp engine (these costs are very similar to the costs calculated in the original reference analysis; the only difference in annual costs is related to the CRF, i.e., changing the interest rate from 10 percent in the original reference analysis to 7 percent in the current analysis). NOx emissions are provided for two cases: a capacity factor of 0.25 (2190 hr/yr) and a capacity factor of 0.75 (6570 hr/yr). The uncontrolled NOx emissions ranged from 1.2 to 37 tpy for the lower capacity case, and the NOx reductions ranged from 1.1 to 33 tpy. For the higher capacity case, uncontrolled NOx emissions ranged from 3.7 to 110 tpy, and the NOx reductions achieved ranged from 3.3 to 100 tpy. The current analysis shows an average cost

effectiveness of \$8,700/ton of NO_x reduction for 2190 hr/yr of operation, and \$2,900/ton of NO_x reduction for 6570 hr/yr operation (these cost effectiveness values are very similar to the costs shown in the original reference analysis).

Based on the cost calculations for engines of varying hp and annual capacity operating, the following linear equations were developed for the capital cost and annual costs for SCR on natural gas 4-stroke lean burn engines:

$$\text{Capital cost} = 107.1 \times (\text{hp}) + 27186$$

$$\text{Annual cost} = 83.64 \times (\text{hp}) + 14718$$

The R² values for these equations are 0.95 for capital cost and 0.98 for annual cost. These equations should be included in the CoST database file under a new equation type for linear equations.

The cost year is not provided in the reference; assumed the cost year is the date of the cost-basis document, 2001\$.

See the cost calculations in worksheet “SCR NG (SJVAPCD)-2003” of the Excel file. [Other cost effectiveness values for SCR are available from the PA DEP that are higher than the cost effectiveness values shown for the SJVAPCD SCR analysis, and other analyses. See the summary of SCR costs in worksheet “Other SCR Cost Info” of the Excel file.]

5.8 SCR (for Diesel Engines) (NSCRICEDS)

The costs and cost effectiveness for applying SCR to diesel lean burn engines is provided in *Alternative Control Techniques Document: Stationary Diesel Engines* (EPA 2010). The assumptions for the original reference analysis are provided in Table 5-6 for SCR for diesel engines, along with changes in assumptions for the current analysis. SCR is a known or demonstrated control technique for lean burn, diesel engines.

Approximately 76 percent of the population of stationary diesel engines is less than 300 hp and the remaining 24 percent is greater than 300 hp. Applications for stationary engines under 300 hp include standby power generation, agriculture, and industrial applications, and less than 5 percent are used for continuous power generation. Applications for stationary engines greater than 300 hp are primarily power generation and are almost evenly divided between continuous duty and standby applications.

The cost analysis provided in the original reference includes an assumption that stationary diesel lean burn engines operate approximately 1000 hr/yr. This assumption is likely appropriate for the majority of those units that are less than 300 hp and for half of the diesel engines greater than 300 hp, i.e., approximately 87 percent of diesel lean burn engines (this ignores the “fewer than 5 percent” used for continuous power generation). For the remaining 13 percent of engines that are greater than 300 hp and used in continuous power generation applications, an assumption for longer operating hours, such as 8000 hr/yr, may be needed to estimate the cost effectiveness.

Table 5-6. SCR for Diesel Lean Burn Engines—Assumptions

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: 90 %	None.
Equipment life: 15 year	None.
Interest rate: 7%	None.
Capital costs: \$98/hp	None.
Annual Costs	
Operating hours: 1000 hr/yr	None.
Annual costs: \$40/hp (based on 1000 hr/yr operation; already includes Capital Recovery)	None.

The original reference analysis provided a capital cost of \$98/hp, and based on the mid-range hp rating for four model engines, the capital costs ranged from \$7,300 to \$98,000 for SCR. The original reference analysis provided an annual cost of \$40/hp, and the annual costs ranged from \$3,000 to \$40,000 per year. Uncontrolled NOx emissions factors in the original reference were based on Tier 0 to Tier 3 values¹ and an assumption of 1000 hr/yr operation. Uncontrolled NOx emissions range from 0.25 to 9.2 tpy across the four models, and the NOx reductions ranged from 0.22 to 8.3 tpy.

The current analysis shows an average cost effectiveness of \$9,300/ton of NOx reduction for 1000 hr/yr of operation (no weighting to the average based on engine age was applied). The cost effectiveness over the engine size range varied from \$4,800/ton to \$16,000/ton for diesel engines (and are very similar to the costs shown in the original reference analysis). It is

¹ Federal Standards, from the *Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling—Compression Ignition*. EPA Publication No. EPA420-P-04_009. April 2004.

important to note that the cost effectiveness is correlated to the manufacturing year of the diesel engine, i.e., the Tier limit for NOx emissions. Older engines manufactured prior to 1998 have the most lenient emissions limit while later model years have more stringent NOx emission limits (lower baseline emissions). The overall magnitude of emission reduction achieved by the SCR is lower for later model years as compared to earlier years, and therefore, the cost effectiveness values are higher for later model years.

[Note: This analysis shows emission reductions and cost effectiveness for existing and new diesel engines through approximately 2011, the last year for phase in of the Tiered emission values. The original reference provided information (circa 2005) on the age of the stationary engine population, with approximately 57 percent of engines at that time being manufactured prior to 1994 and approximately 42 percent manufactured after 1994 (note that the grouping of the age data does not align well with the Tier years, in that the age data shows breaks in 1994 and 2003 while the Tier ranges show breaks in 1996, 1998, 2002, 2003, etc.). As the diesel engine population continues to age and older engines are retired (i.e., those diesel engines subject to the Pre-1998 and the Tier 1 (1998 to 2003) or Tier 1 (1996 to 2001), etc. and are replaced with newer engines achieving lower NOx baseline emissions, the cost effectiveness for new engines would tend to be in the higher end shown for each model and would contribute to a somewhat higher average cost-effectiveness value. The average cost effectiveness will likely move toward the \$13,000/ton to \$16,000/ton of NOx reduction range.]

See the cost calculations in worksheet “SCR Diesel (EPA Dies ACT)-2010” of the Excel file.

5.9 Applicable SCCs for Lean Burn Engine Control Measures

Table 5-7 lists all of the ICE SCCs that are associated with one or more gas lean burn ICR control measures in the CMDB table called “Table 03_SCCs.” These SCCs were identified with NOx emissions in an EPA query of the NEI for facilities in the Ozone Transport Group Assessment Region (i.e., 37 states that are partially or completely to the east of 100oW longitude). The control measures shown in the column headings in Table 5-7 are the ICE control measures that are currently in the CMDB. Each control measure that was determined to be applicable for a specific SCC is identified with an “N” in the cell, meaning the control measure is “new,” i.e., not currently linked to this particular SCC, but we recommend adding this link in the database. In some cases, we recommend applying new links between existing control measures and existing SCCs. For example, some of the SCCs are for ICE that are fired with relatively uncommon fuels such as process gas, methanol, digester gas, or landfill gas. While we have not

Table 5-7. Potential Reciprocating Engine SCCs to Add to the CMDB and Applicable Control Measures

SCC ^a	SCC Level 1 ^b	SCC Level 2 ^c	SCC Level 3	SCC Level 4	Applicable Control Measures for the Reciprocating Engine SCC ^d										
					NAFRICGS	NAFRICGS	NIRICGD	NIRICGS	NIRICOL	NIRRICOL	NSCRICGD	NSCRICGS	NSCRICOL	NSCRRICOL	NSNCRICGS
20200702	ICE	Ind	Process Gas	Reciprocating Engine	N	N		N					N		N
20200712	ICE	Ind	Process Gas	Reciprocating: Exhaust	N	N		N					N		N
20201602	ICE	Ind	Methanol	Reciprocating Engine			N					N			
20201607	ICE	Ind	Methanol	Reciprocating: Exhaust			N					N			
20201702	ICE	Ind	Gasoline	Reciprocating Engine			N					N			
20201707	ICE	Ind	Gasoline	Reciprocating: Exhaust			N					N			
20280001	ICE	Ind	Equipment Leaks	Equipment Leaks											
20282001	ICE	Ind	Wastewater, Aggregate	Process Area Drains											
20300702	ICE	C/I	Digester Gas	Reciprocating: POTW Digester Gas	N	N		N					N		N
20300707	ICE	C/I	Digester Gas	Reciprocating: Exhaust	N	N		N					N		N
20300802	ICE	C/I	Landfill Gas	Reciprocating	N	N		N					N		N
20400401	ICE	ET	Reciprocating Engine	Gasoline			N					N			
20400402	ICE	ET	Reciprocating Engine	Diesel/Kerosene			N		N	N	N		N	N	
20400404	ICE	ET	Reciprocating Engine	Process Gas	N	N		N							N
20400406	ICE	ET	Reciprocating Engine	Kerosene/Naphtha (Jet Fuel)			N					N			
20400409	ICE	ET	Reciprocating Engine	Liquified Petroleum Gas (LPG)			N					N			

^aSCCs represent reciprocating engine activities that were identified with NOx emissions in the Ozone Transport Assessment Group Region analysis but are not associated with reciprocating engine control measures in the current CMDB.

^bICE means “Internal Combustion Engines.”

^cInd means “Industrial,” C/I means “Commercial/Institutional,” and ET means “Engine Testing.”

^dThe control measure is assumed to be representative for the SCC; control cost data are unavailable for the specific fuel type for the SCC.

located any analyses that determined the applicable controls and related costs for ICE fired with such fuels, similar control measures can be assigned to these SCCs. In order to conduct CoST modeling analyses for these ICE, the most representative available control measures could be assigned. For ICE that burn miscellaneous gaseous fuels, the most representative control measures are those for natural gas-fired ICE. Similarly, for ICE that burn miscellaneous liquid fuels such as methanol, gasoline, kerosene/diesel, and LPG, the most representative available control measures are those for gas- or diesel-fired ICE. Also, for ICE that burn liquid fuels such as diesel/kerosene, the most representative available control measures are those for gas-, diesel-, or oil-fired ICE.

Six new control measures have been added to the CMDB for lean burn engines under this review and these control measures are described in Sections 5.3 through 5.8 of this report. Table 5-8 lists those SCCs that should be associated with the newly added lean burn engine control measures. Each control measure that was determined to be applicable for a specific SCC is identified by a “Y,” which means yes.

In Table 5-9, a number of recommendations were made to delete NOx control measure/SCC combinations from the CMDB. ICE SCCs for evaporative losses from fuel storage and delivery systems are incorrectly associated with NOx control measures in the current CMDB, and we recommend deleting these all NOx control measure/SCC records from the CMDB table called “Table 03_SCCs” because there should be no NOx emissions from the sources represented by these SCCs. In addition, multiple ICE control measures are misassigned to turbine SCCs and we recommend deleting these NOx control measure/SCC records. The reverse issue also exists where multiple turbine control measures are misassigned to ICE SCCs, and we recommend deleting these NOx control measure/SCC records, as well. These control measure/SCC combinations are identified in Table 5-9.

5.10 Pennsylvania General Permit 5 (GP-5) for Natural Gas Compression and/or Processing Facilities

Pennsylvania DEP recently released a general permit for Natural Gas Compression and/or Processing Facilities that includes limits on NOx emissions from ICE. NOx emission limits from this general permit, along with other NOx limits for Pennsylvania, are shown in Table 5-10. Typical emission rates and the cost-effectiveness values for applying certain control measures are shown for lean burn and rich burn engines in Table 5-11.

Table 5-8. Recommended New Control Measures to Associate With Lean Burn Reciprocating Engine SCCs in the CMDB

SCC ^a	SCC Level 1	SCC Level 2	SCC Level 3	SCC Level 4	Applicable Control Measures for the Lean Burn Reciprocating Engine SCC					
					NLEICENG	NLCICE2SNG	NLCICE2SLBNG	NAFRICENG	NSCRICE4SNG	NSCRICEDS
20200102	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Reciprocating						Y
20200107	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Reciprocating; Exhaust						Y
20200252	Internal Combustion Engines	Industrial	Natural Gas	2-cycle Lean Burn	Y	Y	Y	Y	Y	
20200254	Internal Combustion Engines	Industrial	Natural Gas	4-cycle Lean Burn	Y	Y	Y	Y	Y	
20200255	Internal Combustion Engines	Industrial	Natural Gas	2-cycle Clean Burn	Y	Y	Y	Y	Y	
20200256	Internal Combustion Engines	Industrial	Natural Gas	4-cycle Clean Burn	Y	Y	Y	Y	Y	
20200401 ^b	Internal Combustion Engines	Industrial	Large Bore Engine	Diesel			Y			
20200402 ^b	Internal Combustion Engines	Industrial	Large Bore Engine	Dual Fuel (Oil/Gas)			Y			
20200403 ^b	Internal Combustion Engines	Industrial	Large Bore Engine	Cogeneration: Dual Fuel			Y			

^aSCCs represent reciprocating engine activities that were identified with NO_x emissions in the recent Ozone Transport Region analysis but are not associated with reciprocating engine control measures in the current CMDB.

^bThe control measure is assumed to be representative for the SCC; control cost data are unavailable for the specific fuel type for the SCC.

Table 5-9. Recommended Control Measure Deletions From SCCs in the CMDB

SCC	SCC Level 1	SCC Level 2	SCC Level 3	SCC Level 4	Control Measures Recommended for Deletion
20200106	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Reciprocating: Evap Losses	All NOx control measures
20200206	Internal Combustion Engines	Industrial	Natural Gas	Reciprocating: Evap Losses	All NOx control measures
20200306	Internal Combustion Engines	Industrial	Gasoline	Reciprocating: Evap Losses	All NOx control measures
20200406	Internal Combustion Engines	Industrial	Large Bore Engine	Reciprocating: Evap Losses	All NOx control measures
20200506	Internal Combustion Engines	Industrial	Residual/Crude Oil	Reciprocating: Evap Losses	All NOx control measures
20200906	Internal Combustion Engines	Industrial	Kerosene/Naphtha (Jet Fuel)	Reciprocating: Evap Losses	All NOx control measures
20201006	Internal Combustion Engines	Industrial	Liquified Petroleum Gas (LPG)	Reciprocating: Evap Losses	All NOx control measures
20300106	Internal Combustion Engines	Commercial/Institutional	Distillate Oil (Diesel)	Reciprocating: Evap Losses	All NOx control measures
20300206	Internal Combustion Engines	Commercial/Institutional	Natural Gas	Reciprocating: Evap Losses	All NOx control measures
20300306	Internal Combustion Engines	Commercial/Institutional	Gasoline	Reciprocating: Evap Losses	All NOx control measures
20301006	Internal Combustion Engines	Commercial/Institutional	Liquified Petroleum Gas (LPG)	Reciprocating: Evap Losses	All NOx control measures
20200108	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Turbine: Evap Losses	All NOx control measures
20200109	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Turbine: Exhaust	NNSCRRBIC
20200208	Internal Combustion Engines	Industrial	Natural Gas	Turbine: Evap Losses	All NOx control measures
20200209	Internal Combustion Engines	Industrial	Natural Gas	Turbine: Exhaust	NNSCRRBIC2
20200908	Internal Combustion Engines	Industrial	Kerosene/Naphtha (Jet Fuel)	Turbine: Evap Losses	All NOx control measures
20200909	Internal Combustion Engines	Industrial	Kerosene/Naphtha (Jet Fuel)	Turbine: Exhaust	NNSCRRBGD

(continued)

Table 5-9. Recommended Control Measure Deletions From SCCs in the CMDB (continued)

SCC	SCC Level 1	SCC Level 2	SCC Level 3	SCC Level 4	Control Measures Recommended for Deletion
20201008	Internal Combustion Engines	Industrial	Liquified Petroleum Gas (LPG)	Turbine: Evap Losses	All NOx control measures
20201009	Internal Combustion Engines	Industrial	Liquified Petroleum Gas (LPG)	Turbine: Exhaust	NNSCRRBGD
20201011	Internal Combustion Engines	Industrial	Liquified Petroleum Gas (LPG)	Turbine	NNSCRRBGD
20201013	Internal Combustion Engines	Industrial	Liquified Petroleum Gas (LPG)	Turbine: Cogeneration	NNSCRRBGD
20300108	Internal Combustion Engines	Commercial/Institutional	Distillate Oil (Diesel)	Turbine: Evap Losses	All NOx control measures
20300109	Internal Combustion Engines	Commercial/Institutional	Distillate Oil (Diesel)	Turbine: Exhaust	NNSCRRBIC
20300208	Internal Combustion Engines	Commercial/Institutional	Natural Gas	Turbine: Evap Losses	All NOx control measures
20300209	Internal Combustion Engines	Commercial/Institutional	Natural Gas	Turbine: Exhaust	NNSCRRBIC2
20200105	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Reciprocating: Crankcase Blowby	NNSCRWGTOL, NWTINGTOL
20200107	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Reciprocating: Exhaust	NSCRWGTOL, NWTINGTOL
20200205	Internal Combustion Engines	Industrial	Natural Gas	Reciprocating: Crankcase Blowby	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200207	Internal Combustion Engines	Industrial	Natural Gas	Reciprocating: Exhaust	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200252	Internal Combustion Engines	Industrial	Natural Gas	2-cycle Lean Burn	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200253	Internal Combustion Engines	Industrial	Natural Gas	4-cycle Rich Burn	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200254	Internal Combustion Engines	Industrial	Natural Gas	4-cycle Lean Burn	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200255	Internal Combustion Engines	Industrial	Natural Gas	2-cycle Clean Burn	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG

(continued)

Table 5-9. Recommended Control Measure Deletions From SCCs in the CMDDB (continued)

SCC	SCC Level 1	SCC Level 2	SCC Level 3	SCC Level 4	Control Measures Recommended for Deletion
20200256	Internal Combustion Engines	Industrial	Natural Gas	4-cycle Clean Burn	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200905	Internal Combustion Engines	Industrial	Kerosene/Naphtha (Jet Fuel)	Reciprocating: Crankcase Blowby	NSCRWGTJF, NWTINGTJF
20200907	Internal Combustion Engines	Industrial	Kerosene/Naphtha (Jet Fuel)	Reciprocating: Exhaust	NSCRWGTJF, NWTINGTJF
20300105	Internal Combustion Engines	Commercial/Institutional	Distillate Oil (Diesel)	Reciprocating: Crankcase Blowby	NNSCRWGTOL, NWTINGTOL
20300107	Internal Combustion Engines	Commercial/Institutional	Distillate Oil (Diesel)	Reciprocating: Exhaust	NSCRWGTOL, NWTINGTOL
20300205	Internal Combustion Engines	Commercial/Institutional	Natural Gas	Reciprocating: Crankcase Blowby	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20300207	Internal Combustion Engines	Commercial/Institutional	Natural Gas	Reciprocating: Exhaust	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG

Table 5-10. NO_x Control Requirements for RICE in Pennsylvania

State	Source Category Covered	NO _x Control Level	Reference
Pennsylvania	153 ton NO _x /season	≥2400 hp: 3 g/bhp-hr (220 ppm)	IEPA 2007
Pennsylvania (proposed values) [Assume proposal was 2011Mar26]	General Permit—Natural Gas Production and Processing Facility, SI, ICE	Existing LB or RB, 100 to 1500 hp: 2 g/bhp-hr New, Reconfigured, LB ≤100 hp: 2 g/bhp-hr New, Reconfigured, LB 100 to 637 hp: 1 g/bhp-hr New, Reconfigured, LB >637 hp: 0.5 g/bhp-hr	OTC 2012
Pennsylvania (amended 2013Feb02)	Natural Gas Compression and Processing, NG, SI, ICE, includes facilities with actual or potential emissions <100 tpy NO _x , and <25 tpy NO _x in 5 counties.	New, Reconfigured LB or RB, ≤100 hp: 2 g/bhp-hr New, Reconfigured LB, 100 to 500 hp: 1 g/bhp-hr New, Reconfigured LB, >500 hp: 0.5 g/bhp-hr New, Reconfigured RB, 100 to 500 hp: 0.25 g/bhp-hr New, Reconfigured RB, >500 hp: 0.2 g/bhp-hr	PA DEP 2013
Pennsylvania	Interstate Pollution Transport Reduction, Emission of NO _x from Stationary ICE	LB, >2400 hp: 3.0 g/bhp-hr RICE, RB, >2400 hp: 1.5 g/bhp-hr	DE 2012

Table 5-11. Characteristics of NO_x Emissions and Controls for RICE

Engine Type and Size	Uncontrolled Emissions	Emissions	Cost Effectiveness for NO _x Reductions	Reference
Lean burn				
LB >500 hp	NA	SCR, stack test, 0.22 to 0.50 g/bhp-hr	SCR: \$71,000 to \$60,000/ton (for 500 to 4000 hp)	PA DEP 2013, p. 22
LB 100 to 500 hp	1 to 16.4 g/bhp-hr	NA	SCR: >\$42,000/ton	PA DEP 2013, p. 20
LB <100 hp	2 g/bhp-hr	2 g/bhp-hr	SCR: >\$48,000/ton	PA DEP 2013, p. 17
Rich burn				
RB >500 hp	13 to 16 g/bhp-hr	NSCR: stack test, 0.02 to 0.14 g/bhp-hr	NA	PA DEP 2013, p. 28, 29
RB 100 to 500 hp	13 to 16.4 g/bhp-hr.	NA	NSCR: \$177/ton	PA DEP 2013, p. 25, 26
RB <100 hp	11.41 to 21.08 g/bhp-hr	NSCR: <2 g/bhp-hr, at least 90% reduction	NSCR: <\$650/ton for 100 hp NSCR: <\$1200/ton for 50 hp	PA DEP 2013, p. 17

APPENDIX A
AMMONIA REFORMERS

Copies of database tables showing all records for ammonia reformer controls, highlighting revisions.

Appendix A

Table A-1. CMDB Table 06 References (New)

Data Source	Description
AR-1	Indian Nations Council of Governments (INCOG), 2008: Indian Nations Council of Governments (INCOG), "Tulsa Metropolitan Area 8-Hour Ozone Flex Plan: 2008 8-O3 Flex Program," March 6, 2008. Downloaded from http://www.epa.gov/ozoneadvance/pdfs/Flex-Tulsa.pdf

Table A-2. CMDB Table 01 Summary

cmname	Cm Abbreviation	Pechan Meas Code	Major Poll	Control Technology	Source Group	Sector	Class	Equip Life	Net Device Code	Date Reviewed	Data Source	Months	Description
Low NOx Burner; Ammonia—NG-Fired Reformers	NLNBFRNG	N0561	NOx	Low NOx Burner	Ammonia—NG-Fired Reformers	ptnonipm	Known	10	204 205	2013	AR-1 186		Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to small (<1 ton NOx per OSD) ammonia production operations with natural gas-fired reformers (SCC 30100306) and uncontrolled NOx emissions greater than 10 tons per year. Discussion: LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Low NOx Burner and Flue Gas Recirculation; Ammonia—NG-Fired Reformers	NLNBFRNG	N0562	NOx	Low NOx Burner and Flue Gas Recirculation	Ammonia—NG-Fired Reformers	ptnonipm	Known	10		2006	72 172 175 179 186		Application: This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to small (<1 ton NOx per OSD) ammonia production operations with natural gas-fired reformers (SCC 30100306) and uncontrolled NOx emissions greater than 10 tons per year. Discussion: LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Low NOx Burner and Flue Gas Recirculation; Ammonia—Oil-Fired Reformers	NLNBFROL	N0572	NOx	Low NOx Burner and Flue Gas Recirculation	Ammonia—Oil-Fired Reformers	ptnonipm	Known	10		2006	72		Application: This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to ammonia production operations with oil-fired reformers (SCC 30100307). Discussion: LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Low NOx Burner and Flue Gas Recirculation; Ammonia Prod; Feedstock Desulfurization	NLNBFAFD	N0622	NOx	Low NOx Burner and Flue Gas Recirculation	Ammonia Prod; Feedstock Desulfurization	ptnonipm	Known	10		2006	72 172 175 179 185		Application: This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to small (<1 ton per OSD) feedstock desulfurization processes in ammonia products operations (SCC 30100305) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: It is assumed that the superheated steam needed to regenerate the activated carbon bed used in the desulfurization process is the NOx source. LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Oxygen Trim and Water Injection; Ammonia—NG-Fired Reformers	NOTWIFRNG	N0563	NOx	Oxygen Trim and Water Injection	Ammonia—NG-Fired Reformers	ptnonipm	Known	10		2006	72 172 175 179 184 185		Application: This control is the use of OT + WI to reduce NOx emissions This control is applicable to small (<1 ton NOx per OSD) ammonia production operations with natural gas-fired reformers (SCC 30100306) and uncontrolled NOx emissions greater than 10 tons per year. This control is also applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).

(continued)

Table A-2. CMDB Table 01 Summary (continued)

cmname	Cm Abbreviation	Pechan Meas Code	Major Poll	Control Technology	Source Group	Sector	Class	Equip Life	Net Device Code	Date Reviewed	Data Source	Months	Description
Selective Catalytic Reduction; Ammonia—NG-Fired Reformers	NSCRFRNG	N0564	NOx	Selective Catalytic Reduction	Ammonia—NG-Fired Reformers	ptnonipm	Known	20	139	2006	72 167 175 179 224 225 226		Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. Applies to natural-gas fired reformers involved in the production of ammonia (SCC 30100306) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water.
Selective Catalytic Reduction; Ammonia—Oil-Fired Reformers	NSCRFROL	N0573	NOx	Selective Catalytic Reduction	Ammonia—Oil-Fired Reformers	ptnonipm	Known	20	139	2006	72		Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. Applies to natural-gas fired reformers involved in the production of ammonia (SCC 30100306) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or sup-ports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).

(continued)

Table A-2. CMDB Table 01 Summary (continued)

cmname	Cm Abbreviation	Pechan Meas Code	Major Poll	Control Technology	Source Group	Sector	Class	Equip Life	Net Device Code	Date Reviewed	Data Source	Months	Description
Selective Non-Catalytic Reduction—Ammonia; NG-Fired Reformers	NSNCRFRNG	N0565	NOx	Selective Non-Catalytic Reduction	Ammonia—NG-Fired Reformers	ptnonipm	Known	20	107	2006	72 172 175 179 185		Application: This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to small (<1 ton NOx per OSD) ammonia production natural gas fired reformers (SCC 30100306) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: SNCR is the reduction of NOx in flue gas to N2 and water vapor. This reduction is done with a nitrogen based reducing reagent, such as ammonia or urea. The reagent can react with a number of flue gas components. However, the NOx reduction reaction is favored for a specific temperature range and in the presence of oxygen (EPA, 2002). Both ammonia and urea are used as reagents. The cost of the reagent represents a large part of the annual costs of an SNCR system. Ammonia is generally less expensive than urea. However, the choice of reagent is also based on physical properties and operational considerations (EPA, 2002). Ammonia can be utilized in either aqueous or anhydrous form. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Urea based systems have several advantages, including several safety aspects. Urea is a nontoxic, less volatile liquid that can be stored and handled more safely than ammonia. Urea solution droplets can penetrate farther into the flue gas when injected into the boiler, enhancing mixing (EPA, 2002). Because of these advantages, urea is more commonly used than ammonia in large boiler applications.
Low NOx Burner; Ammonia—Oil-Fired Reformers	NLNBUFROL	N0571	NOx	Low NOx Burner	Ammonia—Oil-Fired Reformers	ptnonipm	Known	10	204 205	2006	72		Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to ammonia production operations with oil-fired reformers (SCC 30100307). Discussion: LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Selective Non-Catalytic Reduction—Ammonia; Oil-Fired Reformers	NSNCRFROL	N0574	NOx	Selective Non-Catalytic Reduction	Ammonia—Oil-Fired Reformers	ptnonipm	Known	20	107	2006	72		Application: This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to ammonia production natural gas fired reformers (SCC 30100306) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: SNCR is the reduction of NOx in flue gas to N2 and water vapor. This reduction is done with a nitrogen based reducing reagent, such as ammonia or urea. The reagent can react with a number of flue gas components. However, the NOx reduction reaction is favored for a specific temperature range and in the presence of oxygen (EPA, 2002). Both ammonia and urea are used as reagents. The cost of the reagent represents a large part of the annual costs of an SNCR system. Ammonia is generally less expensive than urea. However, the choice of reagent is also based on physical properties and operational considerations (EPA, 2002). Ammonia can be utilized in either aqueous or anhydrous form. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Urea based systems have several advantages, including several safety aspects. Urea is a nontoxic, less volatile liquid that can be stored and handled more safely than ammonia. Urea solution droplets can penetrate farther into the flue gas when injected into the boiler, enhancing mixing (EPA, 2002). Because of these advantages, urea is more commonly used than ammonia in large boiler applications.

(continued)

Table A-2. CMDB Table 01 Summary (continued)

cmname	Cm Abbreviation	Pechan Meas Code	Major Poll	Control Technology	Source Group	Sector	Class	Equip Life	Net Device Code	Date Reviewed	Data Source	Months	Description
Low NOx Burner; Ammonia Production; Other Not Classified	NLNBUAONC		NOx	Low NOx Burner	Ammonia Production—Other Not Classified	ptnonipm	Known	10	204 205	2013	AR-1 186		Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Low NOx Burner and Flue Gas Recirculation; Ammonia Production; Other Not Classified	NLNBFAONC		NOx	Low NOx Burner and Flue Gas Recirculation	Ammonia Production—Other Not Classified	ptnonipm	Known	10		2013	72 172 175 179 186		Application: This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Selective Non-Catalytic Reduction—Ammonia; Ammonia Production; Other Not Classified	NSNCRAONC		NOx	Selective Non-Catalytic Reduction	Ammonia Production—Other Not Classified	ptnonipm	Known	20	107	2013	72 172 175 179 185		Application: This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control is applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: SNCR is the reduction of NOx in flue gas to N2 and water vapor. This reduction is done with a nitrogen based reducing reagent, such as ammonia or urea. The reagent can react with a number of flue gas components. However, the NOx reduction reaction is favored for a specific temperature range and in the presence of oxygen (EPA, 2002). Both ammonia and urea are used as reagents. The cost of the reagent represents a large part of the annual costs of an SNCR system. Ammonia is generally less expensive than urea. However, the choice of reagent is also based on physical properties and operational considerations (EPA, 2002). Ammonia can be utilized in either aqueous or anhydrous form. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Urea based systems have several advantages, including several safety aspects. Urea is a nontoxic, less volatile liquid that can be stored and handled more safely than ammonia. Urea solution droplets can penetrate farther into the flue gas when injected into the boiler, enhancing mixing (EPA, 2002). Because of these advantages, urea is more commonly used than ammonia in large boiler applications.
Oxygen Trim and Water Injection; Ammonia Production; Other Not Classified	NOTWIAONC		NOx	Oxygen Trim and Water Injection	Ammonia Production—Other Not Classified	ptnonipm	Known	10		2013	72 172 175 179 184 185		Application: This control is the use of OT + WI to reduce NOx emissions This control is applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).

(continued)

Table A-2. CMDB Table 01 Summary (continued)

cmname	Cm Abbreviation	Pechan Meas Code	Major Poll	Control Technology	Source Group	Sector	Class	Equip Life	Net Device Code	Date Reviewed	Data Source	Months	Description
Selective Catalytic Reduction; Ammonia Production; Other Not Classified	NSCRAONC		NOx	Selective Catalytic Reduction	Ammonia Production—Other Not Classified	ptnonipm	Known	20	139	2013	72 167 175 179 224 225 226		Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control is applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water.

Table A-3. CMDB Table 02 Efficiencies

cmabbreviation	Pollutant	Locale	Effective Date	existingmeasureabbr	nelexistingdevcode	minemissions	maxemissions	controlefficiency	costyear	costper ton	ruleeff	rulepen	equationtype	caprefactor	discountrate	capannratio	incrementalcpt	Details
NLNBFAFPD	NOx				0	0	365	60	1990	2560	100	100	cpton	0.1424		5.9	2470	Applied to small source types
NLNBFAFPD	NOx				0	365		60	1990	590	100	100	cpton	0.1424		7.5	280	Applied to large source types
NLNBFFRNG	NOx				0	0	365	60	1990	2560	100	100	cpton	0.1424		5.9	2470	Applied to small source types
NLNBFFRNG	NOx				0	365		60	1990	590	100	100	cpton	0.1424		7.5	280	Applied to large source types
NLNBFFROL	NOx				0	0	365	60	1990	1120	100	100	cpton	0.1424		5.9	1080	Applied to small source types
NLNBFFROL	NOx				0	365		60	1990	390	100	100	cpton	0.1424		7.5	190	Applied to large source types
NLNBUFROL	NOx				0	0	365	50	1990	400	100	100	cpton	0.1424		5.5		Applied to small source types
NLNBUFROL	NOx				0	365		50	1990	430	100	100	cpton	0.1424		5.5		Applied to large source types
NOTWIFRNG	NOx				0	0	365	65	1990	680	100	100	cpton	0.1424		2.9		Applied to small source types
NOTWIFRNG	NOx				0	365		65	1990	320	100	100	cpton	0.1424		2.9		Applied to large source types
NSCRFRNG	NOx				0	0	365	90	1999	2366	100	100	cpton	0.0944		10		Applied to small source types
NSCRFRNG	NOx				0	365		90	1999	2366	100	100	cpton	0.0944		9.6		Applied to large source types
NSCRFROL	NOx				0	0	365	80	1990	1480	100	100	cpton	0.0944		10	1910	Applied to small source types
NSCRFROL	NOx				0	365		80	1990	810	100	100	cpton	0.0944		9.6	940	Applied to large source types
NSNCRFRNG	NOx				0	0	365	50	1990	3870	100	100	cpton	0.0944		9.4	2900	Applied to small source types
NSNCRFRNG	NOx				0	365		50	1990	1570	100	100	cpton	0.0944		8.2	840	Applied to large source types
NSNCRFROL	NOx				0	0	365	50	1990	2580	100	100	cpton	0.0944		9.4	1940	Applied to small source types
NSNCRFROL	NOx				0	365		50	1990	1050	100	100	cpton	0.0944		8.2	560	Applied to large source types
NLNBUFRNG	NOx				0	0	365	50	1990	820	100	100	cpton	0.1424		5.5		Applied to small source types; no new information was available for small sources during 2013 update
NLNBUFRNG	NOx				0	365		50	2008	800	100	100	cpton	0.1424		5.9		Applied to large source types; equipment life of 10 years and 7% interest

APPENDIX B

COMBUSTION TURBINES

Copies of the database tables for showing all records for Combustion Turbines NOx controls are provided. Changes are highlighted in red font.

- Table B-1. CMDB Table 01_Summary
- Table B-2. CMDB Table 02_Efficiencies
- Table B-3. CMDB Table 04_Equations
- Table B-4. Additional CMDB Table 06_References

Table B-1. CMDB Table 01_Summary

cmname	cmabbreviation	pechanmea scode	majorpoll	controltechnology	sourcegroup	sector	class	equiplife	neidevicecode	datereviewed	datasource	months
Dry Low NOx Combustion; Gas Turbines—Natural Gas	NDLNCGTNG	N0243	NOx	Dry Low NOx Combustion	Gas Turbines— Natural Gas	ptnonipm	Known	15	204 205	2013	72 172 175 179 22 3 CT-2 CT-6	
SCR + Dry Low NOx Combustion; Gas Turbines—Natural Gas	NSCRDGTNG	N0244	NOx	SCR + DLN Combustion	Gas Turbines— Natural Gas	ptnonipm	Known	15		2013	72 172 175 179 22 3 224 CT-2 CT- 3 CT-4 CT-6 CT-8	
Selective Catalytic Reduction and Steam Injecti; Gas Turbines— Natural Gas	NSCRSGTNG	N0245	NOx	Selective Catalytic Reduction and Steam Injection	Gas Turbines— Natural Gas	ptnonipm	Known	15		2013	72 172 175 179 22 3 224 CT-2 CT-3	
Selective Catalytic Reduction and Water Injecti; Gas Turbines— Jet Fuel	NSCRWGTJF	N0502	NOx	Selective Catalytic Reduction and Water Injection	Gas Turbines— Jet Fuel	ptnonipm	Known	15		2013	72 172 175 179 22 3 CT-2 CT-7	
Selective Catalytic Reduction and Water Injecti; Gas Turbines— Natural Gas	NSCRWGTNG	N0246	NOx	Selective Catalytic Reduction and Water Injection	Gas Turbines— Natural Gas	ptnonipm	Known	15		2013	72 172 175 179 22 3 224 CT-2 CT- 3 CT-8	
Selective Catalytic Reduction and Water Injecti; Gas Turbines— Oil	NSCRWGTOL	N0232	NOx	Selective Catalytic Reduction and Water Injection	Gas Turbines— Oil	ptnonipm	Known	15		2013	72 172 175 179 22 3 224 CT-2 CT-7	
Steam Injection; Gas Turbines—Natural Gas	NSTINGTNG	N0242	NOx	Steam Injection	Gas Turbines— Natural Gas	ptnonipm	Known	15		2013	72 172 175 184 22 3 CT-2	
Water Injection; Gas Turbines—Jet Fuel	NWTINGTJF	N0501	NOx	Water Injection	Gas Turbines— Jet Fuel	ptnonipm	Known	15		2013	72 172 175 184 22 3 CT-2	
Water Injection; Gas Turbines—Natural Gas	NWTINGTNG	N0241	NOx	Water Injection	Gas Turbines— Natural Gas	ptnonipm	Known	15		2013	72 172 175 184 22 3 CT-2	
Water Injection; Gas Turbines—Oil	NWTINGTOL	N0231	NOx	Water Injection	Gas Turbines— Oil	ptnonipm	Known	15		2013	72 172 175 184 22 3 CT-2	
Catalytic Combustion; Gas Turbine—Natural Gas	NCATCGTNG	N/A	NOx	Catalytic Combustion	Gas Turbines— Natural Gas	ptnonipm	Emerging	15		2013	CT-1 CT-2	
EMx and Dry Low NOx Combustion; Gas Turbines—Natural Gas	NEMXDGTNG	N/A	NOx	EMx and Dry Low NOx Combustion	Gas Turbines— Natural Gas	ptnonipm	Emerging	15		2013	CT-1 CT-2 CT- 3 CT-4 CT-5	
EMx and Water Injection; Gas Turbines—Natural Gas	NEMXWGTNG	N/A	NOx	EMx and Water Injection	Gas Turbines— Natural Gas	ptnonipm	Emerging	15		2013	CT-1 CT-3	

*For ease in reading this table, the Description field is included on separate pages.

Table B-1. CMDB Table 01_Summary (continued)

cmabbreviation	Description
NDLNCGTNG	Application: This control is the use of dry low NOx combustion (DLN) technology to reduce NOx emissions. DLN combustion reduces the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control applies to large (83.3 MW to 161 MW) natural gas fired turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: LNBs are designed to “stage” combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
NSCRDGTNG	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to natural gas fired turbines with NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or supports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSCRSGTNG	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to natural gas fired turbines with NOx emissions greater than 10 tons per year.

(continued)

Table B-1. CMDB Table 01_Summary (continued)

cmabbreviation	Description
NSCRSGTNG (cont.)	Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or supports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSCRWGTJF	Application: This control is the selective catalytic reduction of NOx through add-on controls in combination with water injection. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to jet fuel-fired turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water.

(continued)

Table B-1. CMDB Table 01_Summary (continued)

cmabbreviation	Description
NSCRWGTJF (cont.)	Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or supports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSCRWGTNG	Application: This control is the selective catalytic reduction of NOx through add-on controls in combination with water injection. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N₂) and water vapor (H₂O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to natural gas-fired gas turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or supports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSCRWGTOL	Application: This control is the selective catalytic reduction of NOx through add-on controls in combination with water injection. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N₂) and water vapor (H₂O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to oil-fired turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002).

(continued)

Table B-1. CMDB Table 01_Summary (continued)

cmabbreviation	Description
NSCRWGTOL (cont.)	Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx.
	The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required.
	The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water.
	Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or supports, providing thermal and structural stability or to increase surface area (EPA, 2002).
	The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSTINGTNG	Application: This control is the use of steam injection to reduce NOx emissions.
	This control applies to small (3.3 MW to 34.4MW) natural gas-fired gas turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Steam is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The steam can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).
NWTINGTJF	Application: This control is the use of water injection to reduce NOx emissions.
	This control applies to small (3.3 MW to 34.4MW) jet fuel-fired turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).
NWTINGTNG	Application: This control is the use of water injection to reduce NOx emissions.
	This control applies to small (3.3 MW to 34.4MW) natural gas-fired gas turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).
NWTINGTOL	Application: This control is the use of water injection to reduce NOx emissions.
	This control applies to small (3.3 MW to 34.4MW) oil-fired turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).

(continued)

Table B-1. CMDB Table 01_Summary (continued)

cmabbreviation	Description
NCATCGTNG	Application: This control is the use of catalytic combustion to reduce NO_x emissions. Catalytic combustors reduce the amount of NO_x created by oxidizing fuel at lower temperatures (and without a flame) than in conventional combustors. Catalytic combustion uses a catalytic bed to oxidize a lean air fuel mixture within a combustor instead of burning with a flame. The fuel and air mixture oxidizes at lower temperatures than in a conventional combustor, producing less NO_x. Currently installed only on a few 1.4 MW combustion turbines, and commercially available for turbines rated up to 10 MW (CT-1).
NEMXDGTNG	Application: This control is the use of EMx in combination with dry low NO_x combustion. EMx is a post-combustion catalytic oxidation and absorption technology that uses a two-stage catalyst/absorber system for the control of NO_x as well as CO, VOC, and optionally SO_x. A coated catalyst oxidizes NO to NO₂, CO to CO₂, and VOC to CO₂ and water. The NO₂ is then absorbed onto the catalyst surface where it is chemically converted to and stored as potassium nitrates and nitrites. A proprietary regeneration gas is periodically passed through the catalyst to desorb the NO₂ from the catalyst and reduce it to elemental nitrogen (N₂). EMx has been successfully demonstrated on several small combustion turbine projects up to 45 MW. The manufacturer has claimed that EMx can be effectively scaled up to larger turbines (CT-1). Cost estimates for DLN combustion in 2008 dollars are not available. Thus, the total system cost in this analysis in 2008 dollars was developed from 1999 cost estimates for DLN combustion that were escalated to 2008 dollars and added to the available 2008 estimate for the EMx system.
NEMXWGTNG	Application: This control is the use of EMx in combination with water injection. Cost estimates for water injection in 2008 dollars are not available. Thus, the total system cost in this analysis in 2008 dollars was developed from 1999 cost estimates for water injection that were escalated to 2008 dollars and added to the available 2008 estimate for the EMx system.

Table B-2. CMDB Table 02_Efficiencies

cnabbreviation	pollutant	locale	Effective Date	existingmeasureabbr	netexistingdevcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equationtype	caprefactor	discountrate	capannratio	incrementalcpt	details
NWTINGTNG	NOx				0	0	365	72	1999	1790	100	100	cpton	0.1098		3.1		Applied to small source types (<34.4 MW), uncontrolled emissions <365 tpy
NWTINGTNG	NOx				0	365		72	1999	1000	100	100	cpton	0.1098		2.4		Applied to small source types (<34.4 MW), uncontrolled emissions >365 tpy
NWTINGTNG	NOx				0	365		72	1999	730	100	100	cpton	0.1098		1.6		Applied to large source types
NSCRWGTNG	NOx				0	0	365	94	1999	2790	100	100	cpton	0.1098		3	5840	Applied to small source types (3 to 26 MW), uncontrolled emissions <365 tpy.
NSCRWGTNG	NOx				0	365		94	1999	1370	100	100	cpton	0.1098		2.9	3130	Applied to small source types (3 to 26 MW), uncontrolled emissions >365 tpy.
NSCRWGTNG	NOx				0	365		94	1999	1070	100	100	cpton	0.1098		1.5	1690	Applied to large source types (~80 to 160 MW)
NSCRWGTNG	NOx				0	365		98	2008	1960	100	100	cpton	0.1098		2.5	3170	Applied to large source types (~50 to 180 MW), 1999 costs for WI assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed the costs were essentially the same for NG-fired units. 1999 WI capital and indirect annual costs were escalated to 2008 dollars using ratio of 2008 to 1999 CEP cost indexes, direct annual costs for WI were assumed to be the same in 2008 as in 1999, and resulting 2008 costs were added to the 2008 SCR costs from ref CT-3.
NEMXWGTNG	NOx				0	365		99	2008	2960	100	100	cpton	0.1098		2.9	7120	Applied to large source types (50 to 180 MW); WI costs estimated using the same procedure as for NSCRWGTNG applied to large sources.
NSTINGTNG	NOx				0	0	365	80	1999	1690	100	100	cpton	0.1098		3.5		Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy, 1999 costs for SI assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed WI costs were essentially the same for NG-fired units (assumed same pattern holds for steam injection).
NSTINGTNG	NOx				0	365		80	1999	820	100	100	cpton	0.1098		3.5		Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy, 1999 costs for SI assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed WI costs were essentially the same for NG-fired units (assumed same pattern holds for steam injection).
NSTINGTNG	NOx				0	365		80	1999	500	100	100	cpton	0.1098		3.0		Applied to large source types (~80 to 160 MW), 1999 costs for SI assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed WI costs were essentially the same for NG-fired units (assumed same pattern holds for steam injection).
NSCRSGTNG	NOx				0	0	365	95	1999	2570	100	100	cpton	0.1098		3.3	5550	Applied to small source types (3 to 26 MW), uncontrolled emissions <365 tpy.

(continued)

Table B-2. CMDB Table 02_Efficiencies (continued)

cmabbreviation	pollutant	locale	Effective Date	existingmeasreabbr	netexistingdevcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equationtype	caprefactor	discountrate	capannratio	incrementalcpt	details
NSCRSGTNG	NOx				0	365		95	1999	1380	100	100	cpton	0.1098		3.1	2870	Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy.
NSCRSGTNG	NOx				0	365		95	1999	570	100	100	cpton	0.1098		2.7	1810	Applied to large source types (~80 to 160 MW)
NSCRGYNG	NOx				0	365		95	2008	1420	100	100	cpton	0.1098		3.9	3170	Applied to large source types (50 to 180 MW)
NDLNCGTNG	NOx				0	0	365	84	1999	300	100	100	cpton	0.1098		5	540	Applied to small source types
NDLNCGTNG	NOx				0	365		84	1999	130	100	100	cpton	0.1098		7.4	140	Applied to large source types
NSCRDGTNG	NOx				0	0	365	94	1999	1800	100	100	cpton	0.1098		2.9	11900	Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy.
NSCRDGTNG	NOx				0	365		94	1999	990	100	100	cpton	0.1098		3.6	6320	Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy.
NSCRDGTNG	NOx				0	365		94	1999	390	100	100	cpton	0.1098		4.2	3340	Applied to large source types (~160 MW)
NSCRDGTNG	NOx				0	365			2007								18900	Applied to small source types (up to 40 MW, uncontrolled emissions <365 tpy)
NSCRDGTNG	NOx				0		365		2007								7510	Applied to small source types (up to 40 MW, uncontrolled emissions >365 tpy)
NSCRDGTNG	NOx				0	365		94	2008	1040	100	100	cpton	0.1098		4.6	5560	Applied to large source types (~50 to 180 MW), 1999 costs for DLN were estimated based on data in ref CT-2. Escalated these costs to 2008 dollars using ratio of 2008 to 1999 CEP cost indexes and added to the 2008 SCR costs from ref CT-3.
NEMXDGTNG	NOx						365		1999	2860							14940	Applied to small source types (<26 MW), uncontrolled emissions <365 tpy
NEMXDGTNG	NOx					365			1999	1720							10270	Applied to small source types (<26 MW), uncontrolled emissions >365 tpy
NEMXDGTNG	NOx					365			1999	840							6600	Applied to large source types (170 MW), uncontrolled emissions >365 tpy
NEMXDGTNG	NOx				0		365											Applied to small source types
NEMXDGTNG	NOx				0	365		99	2008	2040	100	100	cpton	0.1098		4.1	12370	Applied to large source types (50 to 180 MW); DLN costs estimated in 1999 dollars were escalated to 2008 dollars using the CEPCL, except parts and repair costs were assumed to be the same in 2008 as in 1999.
NCATCGTNG	NOx				0		365	98	1999	920	100	100	cpton	0.1098		1.7	4760	Applied to small source types (3 to 26 MW), uncontrolled emissions <365 tpy.
NCATCGTNG	NOx				0		365	98	1999	670	100	100	cpton	0.1098		1.2	2580	Applied to small source types (3 to 26 MW), uncontrolled emissions >365 tpy.
NCATCGTNG	NOx				0	365		98	1999	370	100	100	cpton	0.1098		0.7	2200	Applied to large source types (~170 MW)
NWTINGTOL	NOx				0	0	365	68	1999	1630	100	100	cpton	0.1098		3.0		Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy, 1999 costs assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed the costs were essentially the same for NG-fired units.

Table B-2. CMDB Table 02_Efficiencies (continued)

cmabbreviation	pollutant	locale	Effective Date	existingmeasureabbr	neexistingdevcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equationtype	caprefactor	discountrate	capannratio	incrementalcpt	details
NWTINGTOL	NOx				0	365		68	1999	960	100	100	cpton	0.1098		1.8		Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy, 1999 costs assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed the costs were essentially the same for NG-fired units.
NWTINGTOL	NOx				0	365		68	1999	650	100	100	cpton	0.1098		1.6		Applied to large source types (~83 MW), uncontrolled emissions >365 tpy, 1999 costs assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed the costs were essentially the same for NG-fired units.
NSCRWGTOL	NOx				0	0	365	90	1990	3190	100	100	cpton	0.1098		2.9	7620	Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy.
NSCRWGTOL	NOx				0	365		90	1990	1320	100	100	cpton	0.1098		2.3	2450	Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy.
NSCRWGTOL	NOx				0	365		97	2004	1560	100	100	cpton	0.1098		2.3	4790	Applied to large source types (~83 MW), uncontrolled emissions >365 tpy, 1999 costs for WI assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed the costs were essentially the same for NG-fired units. Escalated these costs to 2004 dollars using ratio of 2004 to 1999 CEP cost indexes and added to the 2004 SCR costs from ref CT-7. Control efficiency based on data from analysis for one unit (ref CT-7).
NWTINGTJF	NOx				0	0	365	68	1999	1630	100	100	cpton	0.1098		3.0		Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy, costs assumed to be the same as for oil-fired turbines.
NWTINGTJF	NOx				0	365		68	1999	960	100	100	cpton	0.1098		1.8		Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy, costs assumed to be the same as for oil-fired turbines.
NWTINGTJF	NOx				0	365		68	1999	650	100	100	cpton	0.1098		1.6		Applied to large source types (~83 MW), uncontrolled emissions >365 tpy, costs and control efficiency assumed to be the same as for oil-fired turbines.
NSCRWGTJF	NOx				0	0	365	90	1990	3190	100	100	cpton	0.1098		2.9	7620	Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy, costs assumed to be same as for oil-fired turbines.
NSCRWGTJF	NOx				0	365		90	1990	1320	100	100	cpton	0.1098		2.3	2450	Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy, costs assumed to be same as for oil-fired turbines.
NSCRWGTJF	NOx				0	365		97	2004	1560	100	100	cpton	0.1098		2.3	4790	Applied to large source types (~83 MW), uncontrolled emissions >365 tpy, costs and control efficiency assumed to be same as for oil-fired turbines).

Appendix A

Table B-3. CMDB Table 04_Equations^a

cmabbreviation	cmeqntype	pollutant	costyear	var1	var2	var3	var4	var5	var6	var7	var8	var9	var10
NWTINGTNG	Type 2	NOx	1999	27665	0.69	3700.2	0.95	27665	0.69	3700.2	0.95		
NSCRWGTNG	Type 2	NOx	1999	62962	0.66	8590	0.87	37193	0.63	12065	0.64		
NSCRWGTNG	Type 2	NOx	2007					210883	0.46				
NSCRWGTNG	Type “L”	NOx	2007							1893.8	185570		
NSCRWGTNG	Type 2	NOx	2008	34533	0.85	7236	0.94	10323	0.96	3106	0.94		
NEMXWGTNG	Type 2	NOx	2008	200894	0.68	19215	0.86	160409	0.67	20174	0.78		
NSTINGTNG	Type 2	NOx	1999	43092	0.66	7282.3	0.76	43092	0.66	7282.3	0.76		
NSCRSGTNG	Type 2	NOx	1999	72169	0.66	17551	0.72	37193	0.63	12065	0.64		
NSCRSGTNG	Type 2	NOx	2008	46492	0.82	9434.1	0.86	10323	0.96	3106	0.94		
NDLNCGTNG	Type 2	NOx	1999			676.37	0.96			676.37	0.96		
NDLNCGTNG	Type “L”	NOx	1999	2860.6	25427			2860.6	25427				
NSCRDGTNG	Type 2	NOx	1999	24854	0.79	12725	0.69	37193	0.63	12065	0.64		
NSCRDGTNG	Type 2	NOx	2007	187647	0.54			210883	0.46				
NSCRDGTNG	Type “L”	NOx	2007			2782	167494			1893.8	185570		
NSCRDGTNG	Type 2	NOx	2008	14785	0.97	5250.8	0.9	10323	0.96	3106.1	0.94		
NEMXDGTNG	Type 2	NOx	1999	58237	0.78	15004	0.78	65163	0.72	13702	0.76		
NEMXDGTNG	Type 2	NOx	2008	129611	0.74	23051	0.78	160409	0.67	20174	0.78		
NCATCGTNG	Type 2	NOx	1999	20668	0.57	4254.2	0.82						
NCATCGTNG	Type “L”	NOx	1999					N/A	N/A	743.2	54105		
NWTINGTOL	Type 2	NOx	1999	42533	0.6	6776.7	0.8	42533	0.6	6776.7	0.8		
NSCRWGTOL	Type 2	NOx	1990	94337	0.63	25914	0.7						
NSCRWGTOL	Type “L”	NOx	1999					4868.5	349694	1546.1	139203		

^aType “L” is a linear equation; variables are the slope and intercept. No incremental TCI for NCATCGTNG relative to DLN because the capital costs for catalytic combustion are lower than the capital costs for DLN for all but the smallest turbines. The underlying data for 2008 costs for SCR and EMx are for large turbines (50 MW to 180 MW). The underlying data for 2007 costs are for 1 MW to 40 MW turbines.

Table B-4. Additional CMDB Table 06 References

Data Source	Description
CT-1	Bay Area Air Quality Management District, 2010. Preliminary Determination of Compliance. Marsh Landing Generating Station. March 2010. Available at: http://www.energy.ca.gov/sitingcases/marshlanding/documents/other/2010-03-24_Bay_Area_AQMD_PDOC.pdf
CT-2	Onsite Sycom Energy Corporation, 1999. "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines." Prepared for U.S. Department of Energy. Environmental Programs Chicago Operations Office. November 5, 1999. Available at: https://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/gas_turbines_nox_cost_analysis.pdf
CT-3	EmeraChem Power, 2008. Attachment in email from Jeff Valmus, EmeraChem Power, to Weyman Lee, BAAQMD. Request for EMx Cost Information. September 8, 2008. Available at: http://www.baaqmd.gov/~media/Files/Engineering/Public%20Notices/2010/18404/Footnotes/EMx%20BACT%20economic%20analysis%20final09072008.ashx
CT-4	CH2MHill, 2002. Walnut Energy Center Application for Certification." Prepared for California Energy Commission. November 2002. Available at: www.energy.ca.gov/sitingcases/turlock/documents/applicant_files/volume_2/App_08.01E_Eval_Control.pdf .
CT-5	CARB, 2004. California Environmental Protection Agency. Air Resources Board. Report to the Legislature. Gas-Fired Power Plant NOx Emission Controls and Related Environmental Impacts. Stationary Source Division. May 2004. Available at: http://www.arb.ca.gov/research/apr/reports/l2069.pdf
CT-6	Resource Dynamics Corporation, 2001. "Assessment of Distributed Generation Technology Applications." Prepared for Maine Public Utilities Commission. February 2001. Available at: http://www.distributed-generation.com/Library/Maine.pdf
CT-7	Florida Municipal Power Agency, 2004. Chapters 3 and 4 of PSD BACT analysis for Stock Island facility in Key West, Florida. Available at http://www.dep.state.fl.us/air/emission/construction/stockisland/BasisofBACT.pdf and http://www.dep.state.fl.us/air/emission/construction/stockisland/NOxBACT.pdf
CT-8	Energy and Environmental Analysis (An ICF International Company), 2008. Technology Characterization: Gas Turbines. Prepared for Environmental Protection Agency Climate Protection Partnership Division. December 2008. Available at: http://www.epa.gov/chp/documents/catalog_chptech_gas_turbines.pdf

APPENDIX C
GLASS MANUFACTURING

Copies of database tables showing all records for glass manufacturing controls, highlighting revisions.

Appendix A

Table C-1. CMDB Table 01 Summary

cmname	cmabbreviation	pechanm eascode	major poll	controltechnology	sourcegroup	Sector	Class	equiplife	neidevic ecode	daterevi ewed	datasource	Month s	Description
Cullet Preheat; Glass Manufacturing—Container	NCLPTGMCN	N0302	NOx	Cullet Preheat	Glass Manufacturing—Container	ptnonipm	Emerging	10		2013	72 175 182 GM-1		
Cullet Preheat; Glass Manufacturing—Pressed	NCUPHGMPD	N0322	NOx	Cullet Preheat	Glass Manufacturing—Pressed	ptnonipm	Emerging	10		2013	72 175 182 GM-1		
OXY-Firing; Glass Manufacturing—General	NDOXYFGMG	N/A	NOx	OXY-Firing	Glass Manufacturing—General	ptnonipm	Emerging	10			167		
Electric Boost; Glass Manufacturing—General	NELBOGMGN	N0301	NOx	Electric Boost	Glass Manufacturing—Container	ptnonipm	Known	10		2013	GM-1		
Electric Boost; Glass Manufacturing—Container	NELBOGMCN	N0301	NOx	Electric Boost	Glass Manufacturing—Container	ptnonipm	Known	10		2006	72 175 182		
Electric Boost; Glass Manufacturing—Flat	NELBOGMFT	N0311	NOx	Electric Boost	Glass Manufacturing—Flat	ptnonipm	Known	10		2006	72 175 182		
Electric Boost; Glass Manufacturing—Pressed	NELBOGMPD	N0321	NOx	Electric Boost	Glass Manufacturing—Pressed	ptnonipm	Known	10		2006	72 175 182		
Low NOx Burner; Glass Manufacturing—Container	NLNBUGMCN	N0303	NOx	Low NOx Burner	Glass Manufacturing—Container	ptnonipm	Known	10	204 205	2013	72 175 179 182 GM-2		
Low NOx Burner; Glass Manufacturing—Flat	NLNBUGMFT	N0312	NOx	Low NOx Burner	Glass Manufacturing—Flat	ptnonipm	Known	10	204 205	2013	72 175 179 182 GM-2		
Low NOx Burner; Glass Manufacturing—Pressed	NLNBUGMPD	N0323	NOx	Low NOx Burner	Glass Manufacturing—Pressed	ptnonipm	Known	10	204 205	2006	175 179 182		
OXY-Firing; Glass Manufacturing—General	NOXYFGMG	N0306	NOx	OXY-Firing	Glass Manufacturing—Container	ptnonipm	Known	10		2013	GM-1		
OXY-Firing; Glass Manufacturing—Container	NOXYFGMCN	N0306	NOx	OXY-Firing	Glass Manufacturing—Container	ptnonipm	Known	10		2006	72		
OXY-Firing; Glass Manufacturing—Flat	NOXYFGMFT	N0315	NOx	OXY-Firing	Glass Manufacturing—Flat	ptnonipm	Known	10		2006	72		
OXY-Firing; Glass Manufacturing—Pressed	NOXYFGMPD	N0326	NOx	OXY-Firing	Glass Manufacturing—Pressed	ptnonipm	Known	10		2006	72		
Selective Catalytic Reduction; Glass Manufacturing—Container	NSCRGMCN	N03403	NOx	Selective Catalytic Reduction	Glass Manufacturing—Container	ptnonipm	Known	10	139	2013	72 172 175 179 182 224 GM-2		
Selective Catalytic Reduction; Glass Manufacturing—Flat	NSCRGMFT	N0314	NOx	Selective Catalytic Reduction	Glass Manufacturing—Flat	ptnonipm	Known	10	139	2013	72 172 175 179 182 186 224 GM-2		
Selective Catalytic Reduction; Glass Manufacturing—Pressed	NSCRGMPD	N0325	NOx	Selective Catalytic Reduction	Glass Manufacturing—Pressed	ptnonipm	Known	10	139	2006	72 172 175 179 182 186 224		
Catalytic Ceramic Filter; Glass Manufacturing—Flat	CATCFGMFT		NOx	Catalytic Ceramic Filter	Glass Manufacturing—Flat	ptnonipm	Known	20		2013	GM-3		

Table C-1. CMDB Table 01 Summary—Description Field

cmabbreviation	description
NCLPTGMCN	Application: This control is the use of cullet preheat technologies to reduce NOx emissions from glass manufacturing operations. This control is applicable to container glass manufacturing operations classified under 305010402.
NCUPHGMPD	Application: This control is the use of cullet preheat technologies to reduce NOx emissions from glass manufacturing operations. This control is applicable to pressed glass manufacturing operations classified under 305010404.
NDOXYFGMG	Application: This control is the use of OXY-firing in glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called “oxy-firing.” Discussion: The basic rationale for oxy-firing is improved efficiency, i.e., more of the theoretical heat of combustion is transferred to the glass melt and is not lost in the flue gas. Many other combustion modification techniques (e.g., flue gas recirculation, staged combustion, and low excess air combustion) reduce NOx formation but also reduce the combustion efficiency. Oxy-firing was originally developed to improve the combustion efficiency primarily by eliminating the sensible heat lost in heating the nitrogen present in air, which is then lost in the flue gas.
NELBOGMGN	Application: This control is the use of electric boost technologies to reduce NOx emissions from glass manufacturing operations. This control applies to general glass manufacturing operations classified under SCC 30501401.
NELBOGMCN	Application: This control is the use of electric boost technologies to reduce NOx emissions from glass manufacturing operations. This control applies to container glass manufacturing operations classified under SCC 30501402. Discussion: The 250 tons per day plant is assumed to be representative of container glass plants (Pechan, 1998).
NELBOGMFT	Application: This control is the use of electric boost technologies to reduce NOx emissions from glass manufacturing operations. This control applies to flat glass manufacturing operations classified under SCC 30501403. Discussion: The 500 tons per day plant is assumed to be representative of flat glass plants (Pechan, 1998).
NELBOGMPD	Application: This control is the use of electric boost technologies to reduce NOx emissions from glass manufacturing operations. This control applies to pressed glass manufacturing operations classified under SCC 30501403. Discussion: The 50 tons per day plant is assumed to be representative of pressed glass plants (Pechan, 1998).
NLNBUGMCN	Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to container glass manufacturing operations classified under 305010402 with uncontrolled NOx emissions greater than 10 tons per year. Discussion: The 250 tons per day plant is assumed to be representative of container glass plants (Pechan, 1998). LNBs are designed to “stage” combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
NLNBUGMFT	Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to flat glass manufacturing operations classified under 305010404 with uncontrolled NOx emissions greater than 10 tons per year. Discussion: The 500 tons per day plant is assumed to be representative of flat glass plants (Pechan, 1998). LNBs are designed to “stage” combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).

(continued)

Table C-1. CMDB Table 01 Summary—Description Field (continued)

cmabbreviation	description
NLNBUGMPD	Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen used to burn the fuel in a glass furnace. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called “oxy-firing.”
NOXYFGMGN	This control applies to general manufacturing operations. This control applies to general glass manufacturing operations classified under SCC 30501401. Discussion: The basic rationale for oxy-firing is improved efficiency, i.e., more of the theoretical heat of combustion is transferred to the glass melt and is not lost in the flue gas. Many other combustion modification techniques (e.g., flue gas recirculation, staged combustion, and low excess air combustion) reduce NOx formation but also reduce the combustion efficiency. Oxy-firing was originally developed to improve the combustion efficiency primarily by eliminating the sensible heat lost in heating the nitrogen present in air, which is then lost in the flue gas.
NOXYFGMCN	Application: This control is the use of OXY-firing in container glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called “oxy-firing.” Discussion: The basic rationale for oxy-firing is improved efficiency, i.e., more of the theoretical heat of combustion is transferred to the glass melt and is not lost in the flue gas. Many other combustion modification techniques (e.g., flue gas recirculation, staged combustion, and low excess air combustion) reduce NOx formation but also reduce the combustion efficiency. Oxy-firing was originally developed to improve the combustion efficiency primarily by eliminating the sensible heat lost in heating the nitrogen present in air, which is then lost in the flue gas.
NOXYFGMFT	Application: This control is the use of OXY-firing in flat glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called “oxy-firing.” This control applies to flat-glass manufacturing operations with uncontrolled NOx emissions greater than 10 tons per year. Discussion: The basic rationale for oxy-firing is improved efficiency, i.e., more of the theoretical heat of combustion is transferred to the glass melt and is not lost in the flue gas. Many other combustion modification techniques (e.g., flue gas recirculation, staged combustion, and low excess air combustion) reduce NOx formation but also reduce the combustion efficiency. Oxy-firing was originally developed to improve the combustion efficiency primarily by eliminating the sensible heat lost in heating the nitrogen present in air, which is then lost in the flue gas.
NOXYFGMPD	Application: This control is the use of OXY-firing in pressed glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called “oxy-firing.” Discussion: The basic rationale for oxy-firing is improved efficiency, i.e., more of the theoretical heat of combustion is transferred to the glass melt and is not lost in the flue gas. Many other combustion modification techniques (e.g., flue gas recirculation, staged combustion, and low excess air combustion) reduce NOx formation but also reduce the combustion efficiency. Oxy-firing was originally developed to improve the combustion efficiency primarily by eliminating the sensible heat lost in heating the nitrogen present in air, which is then lost in the flue gas.

(continued)

Table C-1. CMDB Table 01 Summary—Description Field (continued)

cmabbreviation	description
NSCRGMCN	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N₂) and water vapor (H₂O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. Applies to glass-container manufacturing processes, classified under SCC 30501402 and uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or sup-ports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSCRGMFT	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N₂) and water vapor (H₂O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. Applies to large(>1 ton NOx per OSD) flat-glass manufacturing operations (SCC 30501403) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or sup-ports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).

(continued)

Table C-1. CMDB Table 01 Summary—Description Field (continued)

cmabbreviation	description
NSCRGMPD	Application: This control is the selective catalytic reduction of NO_x through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NO_x) into molecular nitrogen (N₂) and water vapor (H₂O). The SCR utilizes a catalyst to increase the NO_x removal efficiency, which allows the process to occur at lower temperatures. Applies to pressed-glass manufacturing operations, classified under SCC 30101404 and uncontrolled NO_x emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NO_x control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NO_x molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NO_x within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NO_x. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NO_x reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or sup-ports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NO_x removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NO_x concentration level; molar ratio of injected reagent to uncontrolled NO_x; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
CATCFGMFT	Application: Filter tubes have nanobits of proprietary catalyst are embedded throughout the filter walls. The system can achieve excellent NO_x removal using liquid ammonia that is injected upstream of the filters, reacting with NO_x at the catalyst to form nitrogen gas and water vapor. This control applies to general glass manufacturing operations classified under SCC 30501403.

Table C-2. CMDB Table 02 Efficiencies

cmabbreviation	pollutant	location	Effective Date	existing measure abbr	neexistingd evcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equation type	caprecfactor	discountrate	capannratio	incrementalcpt	details
NCLPTGMCN	NOx				0	365	0	5	2002	5000	100	100	cpton	0.1424		4.5		Applied to large source types
NCLPTGMCN	NOx				0	0	365	5	2002	5000	100	100	cpton	0.1424		4.5		Applied to small source types
NCUPHGMPT	NOx				0	365		5	2002	5000	100	100	cpton	0.1424		4.5		Applied to large source types
NCUPHGMPT	NOx				0	0	365	5	2002	5000	100	100	cpton	0.1424		4.5		Applied to small source types
NELBOGMCN	NOx				0	365		10	1990	7150	100	100	cpton	0.1424		0		Applied to large source types
NELBOGMCN	NOx				0	0	365	10	1990	7150	100	100	cpton	0.1424		0		Applied to small source types
NELBOGMFT	NOx				0	365		10	1990	2320	100	100	cpton	0.1424		0		Applied to large source types
NELBOGMFT	NOx				0	0	365	10	1990	2320	100	100	cpton	0.1424		0		Applied to small source types
NELBOGMPD	NOx				0	365		10	1990	8760	100	100	cpton	0.1424		0		Applied to large source types
NELBOGMPD	NOx				0	0	365	10	1990	2320	100	100	cpton	0.1424		0	8760	Applied to small source types
NELBOGMGN					0	365	0	30	2002	7100	100	100	cpton	0.1424		0		Applied to large source types
NELBOGMGN					0	0	365	30	2002	7100	100	100	cpton	0.1424		0		Applied to small source types
NLNBUGMCN	NOx				0	365		40	2007	1072	100	100	cpton	0.14		4.3	1690	Applied to large source types
NLNBUGMCN	NOx				0	0	365	40	2007	1365	100	100	cpton	0.14		4.2	1690	Applied to small source types
NLNBUGMFT	NOx				0	0	365	40	2007	574	100	100	cpton	0.14		4.2		Applied to small source types
NLNBUGMFT	NOx				0	365		40	2007	447	100	100	cpton	0.14		4.3		Applied to large source types
NLNBUGMPD	NOx				0	365		40	1990	1500	100	100	cpton	0.1424		2.2		Applied to large source types
NLNBUGMPD	NOx				0	0	365	40	1990	1500	100	100	cpton	0.1424		2.2		Applied to small source types
NOxYFGMCN	NOx				0	0	365	85	1990	4590	100	100	cpton	0.1424		2.7		Applied to small source types
NOxYFGMCN	NOx				0	365		85	1990	4590	100	100	cpton	0.1424		2.7		Applied to large source types
NOxYFGMFT	NOx				0	365		85	1990	1900	100	100	cpton	0.1424		2.7		Applied to large source types
NOxYFGMFT	NOx				0	0	365	85	1990	1900	100	100	cpton	0.1424		2.7		Applied to small source types
NDOXYFGMG	NOx				0			85	1999	4277	100	100	cpton					
NOxYFGMPD	NOx				0	0	365	85	1990	3900	100	100	cpton	0.1424		2.7		Applied to small source types
NOxYFGMPD	NOx				0	365		85	1990	3900	100	100	cpton	0.1424		2.7		Applied to large source types
NOxYFGMGN						365	0	85	2002	2353	100	100	cpton	0.1424		2.7		Applied to large source types
NOxYFGMGN						0	365	85	2002	2353	100	100	cpton	0.1424		2.7		Applied to small source types
NSCRGMCN	NOx				0	365	0	75	2007	1684	100	100	cpton	0.1424		4.2		Applied to large source types
NSCRGMCN	NOx				0	0	365	75	2007	2169	100	100	cpton	0.1424		4.5		Applied to small source types
NSCRGMFT	NOx				0	365	0	75	2007	855	100	100	cpton	0.1424		3.7	710	Applied to large source types
NSCRGMFT	NOx				0	0	365	75	2007	957	100	100	cpton	0.1424		3.4		Applied to small source types

(continued)

Table C-2. CMDB Table 02 Efficiencies (continued)

cmabbreviation	pollutant	locale	Effective Date	existing measure abbr	neexistingd evcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equation type	caprecfactor	discountrate	capannratio	incrementalcpt	details
NSCRGMPD	NOx				0	365		75	1990	2530	100	100	cpton	0.1424		1.3		Applied to large source types
NSCRGMPD	NOx				0	0	365	75	1990	2530	100	100	cpton	0.1424		1.3		Applied to small source types
CATCFGMFT	NOx				0	365	0	95	2013	997	100	100	cpton	0.05		4.6		Applied to large source types
CATCFGMFT	NOx				0	0	365	95	2013	1045	100	100	cpton	0.05		4.6		Applied to small source types

Table C-3. CMDB Table 06 References (New)

Data Source	Description
GM-1	Oxygen Enriched Air Staging a Cost-effective Method For Reducing NOx Emissions. Industrial Technologies. April 2002. Available at: http://www1.eere.energy.gov/manufacturing/resources/glass/pdfs/airstaging.pdf
GM-2	Best Available Techniques (BAT) Reference Document for the Manufacture of Glass. European Commission 2013. Available at: http://eippcb.jrc.ec.europa.eu/reference/BREF/GLS_Adopted_03_2012.pdf
GM-3	Confidential Vendor Quote

Table C-4. CMDB Table 04_Equations^a

cmabbreviation	cmeqntype	pollutant	costyear	var1	var2	var3	var4	var5	var6	var7	var8	var9	var10
NLNBUGMCN	Type 2	NOx	2008	30,930	0.45	9,377	0.40						
NLNBUGMFT	Type "L"	NOx	2008	527	664,557	132	150,105						
NSCRGMCN	Type 2	NOx	2008	79,415	0.51								
NSCRGMCN	Type "L"	NOx	2008			643	135,302						
NSCRGMFT	Type "L"	NOx	2008	3,681	1,000,000	842	424,930						

^aType "L" is a linear equation; variables are the slope and intercept.

APPENDIX D

LEAN BURN ENGINES

Copies of the database tables for showing all records for Lean Burn Engine NOx controls are provided:

- Table D-01_Summary
- Table D-02_Efficiencies
- Table D-03_SCCs
- Table D-04_Equations
- Table D-06_References

Table D-01_Summary

cmname	cmabbreviation	pechanme ascode	majorp oll	controltechn ology	sourcegr oup	sector	class	equiplife	neid evic eco de	datereviewe d	datasour ce	months	description
Low Emission Combustion; Lean Burn ICE—NG	NLECICENG		NOx	Low Emission Combustion	Lean Burn ICE— NG	PTNONIPM	Known	10		9/15/2013	ABCD3		Low Emission Combustion includes Precombustion chamber head and related equipment on a Lean Burn engine.
Layered Combustion; Lean Burn ICE 2 stroke—NG	NLCICE2SNG		NOx	Layered Combustion	Lean Burn ICE— NG	PTNONIPM	Known	10		9/15/2013	ABCD1		Layered combustion—2 stroke, Lean Burn, NG (Air Supply; Fuel Supply; Ignition; Electronic Controls; Engine Monitoring). Evaluation for 3 most representative made/models of 2 stroke LB compressor engines. All retrofit combustion-related controls may not be available for all manufacturers and models of 2-stroke lean burn engines. Actual NOx emission rates would be engine design specific. Efficiency achieved may range from 60 to 90%, depending on the make/model of engine (approximate range of NOx emissions of 3.0 to 0.5 g/bhp-hr).
Layered Combustion; Lean Burn ICE 2 stroke Large Bore—NG	NLCICE2SLBNG		NOx	Layered Combustion	Lean Burn ICE— NG	PTNONIPM	Known	10		9/15/2013	ABCD1		Layered combustion—for Large Bore, 2 stroke, Lean Burn, Slow Speed (High Pressure Fuel Injection achieves 90% reduction; Turbocharging achieves 75% reduction; Precombustion chambers achieves 90% reduction; Cylinder Head Modifications). All retrofit combustion-related controls may not be available for all manufacturers and models of 2-stroke lean burn engines. Actual NOx emission rates would be engine design specific. Efficiency achieved may range from 60 to 90%, depending on the make/model of engine (approximate range of NOx emissions of 3.0 to 0.5 g/bhp-hr).
Air to Fuel Ratio Controller; Lean Burn ICE—NG	NAFRCICENG		NOx	Air to Fuel Ratio Controller	Lean Burn ICE— NG	PTNONIPM	Known	10		12/5/2012	ABCD3		
Selective Catalytic Reduction; Lean Burn ICE 4 Stroke—NG	NSCRICE4SNG		NOx	Selective Catalytic Reduction	Lean Burn ICE— NG	PTNONIPM	Known	10		9/15/2013	ABCD1 ABCD2 ABCD3		SCR can be used on Lean Burn, NG engines. Assumed SCR can meet NOx emissions of 0.89 g/bh-hr. This is a Known technology, however there is indication that applicability is engine/unit specific.
Selective Catalytic Reduction; ICE—Diesel	NSCRICEDS		NOx	Selective Catalytic Reduction	ICE— Diesel	PTNONIPM	Known	7		9/15/2013	ABCD4		SCR can be used on Diesel engines.

Table D-02_Efficiencies

cmabbreviation	pollutant	locale	Effective Date	existing measurement abbr	neixisting d evcode	mine missions	maxemissions	control efficiency	cost year	cost per ton	rule eff	rule pen	equation type	cap rec factor	discount rate	cap ann ratio	incremental cap	details
NLEICICENG	NOx	NA	NA	NA	NA	0	365	80	2001	1,000	100	100	cpton	0.1424	7	7.025	NA	
NLCICE2SNG	NOx	NA	NA	NA	NA	0	365	97	2009	4,900	100	100	cpton	0.1424	7	7.024	NA	
NLCICE2SLBNG	NOx	NA	NA	NA	NA	365	0	97	2010	1,500	100	100	cpton	0.1424	7	7.024	NA	Apply to large source types. Assumed Interest Rate of 7 percent (not provided in documentation) to calculate annual costs.
NLCICE2SLBNG	NOx	NA	NA	NA	NA	0	365	97	2010	38,000	100	100	cpton	0.1424	7	7.024	NA	Apply to small source types.
NAFRCICENG	NOx	NA	NA	NA	NA	0	365	80	2001	200	100	100	cpton	0.1424	7	7.023	NA	
NSCRICE4SNG	NOx	NA	NA	NA	NA	0	365	96	2001	2,900	100	100	cpton	0.1424	7	1.401	NA	
NSCRICEDS	NOx	NA	NA	NA	NA	0	365	90	2005	9,300	100	100	cpton	0.1098	7	2.45	NA	

Table D-03_SCCs

cmabbreviation	Source Classification Code	Status
NLECICENG	20200252	
NLECICENG	20200254	
NLECICENG	20200255	
NLECICENG	20200256	
NLCICE2SNG	20200252	
NLCICE2SNG	20200254	
NLCICE2SNG	20200255	
NLCICE2SNG	20200256	
NLCICE2SLBNG	20200252	
NLCICE2SLBNG	20200254	
NLCICE2SLBNG	20200255	
NLCICE2SLBNG	20200256	
NLCICE2SLBNG	20200401	
NLCICE2SLBNG	20200402	
NLCICE2SLBNG	20200403	
NAFRICENG	20200252	
NAFRICENG	20200254	
NAFRICENG	20200255	
NAFRICENG	20200256	
NSCRICE4SNG	20200252	
NSCRICE4SNG	20200254	
NSCRICE4SNG	20200255	
NSCRICE4SNG	20200256	
NSCRICEDS	20200102	
NSCRICEDS	20200107	

Table D-04_Equations

cmabbreviation	cmeqntype	pollutant	costyear	var1	var2	var3	var4	var5	var6	var7	var8	var9	var10
NSCRICE4SNG	linear capital and annual	NOx	2001	107.1	27186	83.64	14718						
NLEICENG	capital and annual	NOx	2001	16019	0.0016	2280.8	0.0016						
NAFRCICENG	linear capital and annual	NOx	2001	1.0337	4354.5	0.1852	619.99						

Table D-06 References

Data Source	Description
ABCD1	OTC 2012. Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions. Final. October 17, 2012.
ABCD2	SJVAPCD 2003. RULE 4702—Internal Combustion Engines—Phase 2. Appendix B, Cost Effectiveness Analysis for Rule 4702 (Internal Combustion Engines—Phase 2). San Joaquin Valley Air Pollution Control District. July 17, 2003. www.arb.ca.gov/pm/pmmeasures/ceffect/rules/sjvapcd_4702.pdf
ABCD3	CARB 2001. Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines. California Environmental Protection Agency, Air Resources Board, Stationary Source Division, Emissions Assessment Branch, Process Evaluation Section. November 2001.
ABCD4	EPA 2010. Alternative Control Techniques Document: Stationary Diesel Engines. March 5, 2010.

APPENDIX E
NOTES PROVIDED HERE TO EPA QUESTIONS ON LEAN BURN RICE

Appendix A

EPA Question 1: What is the applicability of SCR to RICE, especially Lean Burn?

Notes for Question 1

In addition to the two documents cited in Section 5 of the report with costs for selective catalytic reduction (SCR) for Lean Burn (LB) engines, there are several other references that indicate SCR is feasible for LB engines and several that provide input on technical issues related to SCR use for LB engines. In summary, from the references reviewed, SCR seems to be technically feasible in most instances for LB engines, however, SCR application may not be feasible in all cases due to technical issues at individual sites and individual engines. In addition, SCR costs are higher relative to other NO_x control techniques for LB engines. See more detailed discussion below.

SCR can be applied to LB engines, achieving greater than 90 percent NO_x reductions (Table 4 on p. 6 provides a slightly different value, greater than 95 percent). The costs [assumed this referred to capital costs] ranged from \$50/hp to \$125/hp. No annual operating costs were provided. In discussions on p. 8 regarding “catalysts on IC engines” in general (including NSCR, SCR, oxidation, and Lean-NO_x), it is noted that “Thousands of stationary IC engine catalyst applications have been effectively used for stationary IC engine gaseous emission control for five years or more. Some installations, however, do experience performance loss over time,” however the text goes on to explain remedies for catalyst poisoning issues. Costs [capital] for SCR, LB ranged from \$50 to \$125/hp (no cost year provided). (MECA 1997)

The literature suggests that SCR is technically feasible for LB engines but there are problems that make SCR installation questionable. Two stroke (2S) LB engines are sensitive to changes in exhaust pressure, which could be problematic for retrofit of SCR on existing engines, but can be alleviated with proper design and sizing of airflow and exhaust components. This reference cited a presentation that indicated the following issues with SCR: applying SCR to pipeline engines is not feasible because the exhaust temperatures (T) are below the operating window for SCR or where SCR effectiveness is reduced; SCR installations are at unmanned facilities; and SCR has not been demonstrated for variable loads. However, the OTC 2012 reference responded to each of these issues, stating that there are several manufacturers and suppliers that offer SCR systems that indicate their catalysts are capable of effectively operating over a wide range of exhaust gas T; modern software based controls and SCADA communication technologies allow operation from a remote location; and SCR can function properly over a broad range of loads given catalysts that are effective over wide T ranges, modern controls regulate fuel and air flows to ensure combustion O₂ and T are at expected levels

and to regulate reagent flow. A study conducted for retrofitting existing pipeline engines indicates that SCR is a high cost alternative to combustion improvements, primarily due to the high cost of ongoing reagent consumption. (p. 25-26) (There is a similar discussion for SCR for four stroke (4S) LB on p. 39-40; cited presentation at Gas Machinery Conference in October 2011.) (OTC 2012)

Shell indicated they have installed SCR on diesel engines (LB) that they utilize in drilling rig operations. Shell indicated that have been able to achieve greater than 90 percent reduction in NOx emissions while encountering minimal operational issues (see p. 10). (OTC 2012)

The OTC 2012 document indicated that MECA has noted there have been limited examples to date of SCR retrofit on 2S LB engines as demonstration test programs, but the results of these programs have not been published (see p. 27). It appears that SCR for NOx does not appear to be technically infeasible generically but that individual 2S LB engine characteristics and installations may be greatly problematic or not cost effective, although this site-specific issue is not altogether different than other emission reduction technologies (see p.27, 40). (OTC 2012)

The OTC 2012 document indicated that MECA has stated the commercial use of SCR systems for LB stationary engines have been in place since the mid-1980's in Europe and since the early 1990s in the US. One MECA member company has installed over 400 SCR systems worldwide for stationary engines with varying fuel combinations, including dozens of NG compressor engines in the US. These 4S LB engines with urea-SCR achieve >90% NOx reduction (see p.40). (OTC 2012)

EF&EE announced in November 2010 that is received an order from Clean Air Power Inc. for 6 SCR systems, to be installed on large LB NG compressor engines at gas storage sites in TX and MS (see p.40). (OTC 2012)

Clean Air Power cited: 4 SCRs supplied at Pine Prairie Energy Center, Louisiana; 1 SCR supplied at EXTERRAN/TRESPALACIOS, Texas; and 4 SCRs supplied to EXTERRAN/LEAF River, Mississippi (see p.41). (OTC 2012)

A PowerPoint slide presentation from a MARAMA workshop discusses the use of SCR for RICE and LB. Johnson Matthey (JM) included SCR as a feasible control for LB engines in a presentation at a May 2011 MARAMA Workshop. (The SCR systems included Urea and Ethanol as reagents.) SCR operating temperatures range from 700 to 900°F for internal combustion (IC) engines and achieved 90 percent NOx reductions. The budgetary costs

[assumed this referred to capital costs] ranged from \$150/ hp for a 500 hp unit (approximately \$75,000) to \$42/hp for a 3000 hp unit (approximately \$126,000) (cost year not provided). No annual operating costs were provided. JM cited 4 LB engine installations of SCR on gas compressors at 2 locations, including Loudon Compressor Station in Clarksburg, WV and Lodi Compressor/Storage in Kirby Hills, CA. (Chu 2011) These engines are listed in the following table:

SCR for Lean Burn Engines—Johnson Matthey presentation at 2007 MARAMA Workshop

Engine Model	Engine hp	NOx, g/bhp-hr	NOx Reduction, %
CAT G3516	1,340	1.5	90%
CAT G3608	2,370	0.7	90%
CAT G3612	3,550	0.7	90%
CAT G3616	4,735	0.7	90%

References

- (MECA 1997). *Emission Control Technology for Stationary Internal Combustion Engines: Status Report*. Manufacturers of Emission Controls Association (MECA). July 1997.
- (Chu 2011). *NOx Control for Stationary Gas Engines*. W. Chu, Johnson Matthey. Presented at Advances in Air Pollution Control Technology, MARAMA Workshop. May 19, 2011.
- (OTC 2012). *Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions. Final*. October 17, 2012.

EPA Question 2: What are credible estimates of the percentage of RICE NO_x Emissions that are lean burn versus rich burn when RICE emissions are unspecified?

Notes for Question 2

There does not seem to be much information on NO_x emission totals for LB and rich burn (RB) engines. A few references attempted to provide information on the numbers or populations of LB and RB engines. Several of the references highlighted surveys of engine populations and summary information from various engine databases. These data in general tend to point to a large LB engine population, however most of the references noted that RB engines are typically not captured or covered in surveys, databases, or by permits because the RB engines tend to be smaller in size. In general, larger engines tend to be LB and smaller engines tend to be RB. The ERLE 2009 study noted that approximately 73% of the 5,600 engines/horsepower capacity covered in their study of NG pipeline systems are LB, and approximately 6% are RB (the balance is not known). In the KSU 2011 database, approximately 66% of the 4,729 engines used in E&P at major sources are LB and 34% are RB. In addition, the EDF 2008 document cited a 2007 survey conducted for DFW NAA and AA that attempted to identify those engines that did not meet reporting requirement thresholds and were therefore not included in the TCEQ inventory. This reference, which included small engines, indicated that for smaller engines <500 hp, approximately 96% are RB and 4% are LB. The reference also indicated that for larger engines >500 hp, there is approximately a 50-50 split of LB and RB engines and of horsepower capacity. The ETCG 2013 reference also highlights engines in the Barnett Shale region. Data from the TCEQ Barnett Shale Special Inventory (Phase I) survey indicated that the majority of engines in the Barnett Shale are RB (84%). For those engines <240 hp, 95% are RB and 5% are LB, however, in looking at those engines >240 hp, 59% are LB and 41% are RB. More details for each of these references are provided in the discussion that follows.

Note also that the emissions rate in g/bhp-hr for LB engines tend to be higher, and the emissions rate for RB engines tends to be lower. (See the tables under Question 4 of this appendix for relative emission rate values for LB and RB engines in various states and local districts.)

A summary of the information available from various references is provided below.

The CARB 2001 reference indicated that LB engines tend to be larger in size, and smaller engines tend to be RB (p.B-4). (CARB 2001)

EPA received comments from the Interstate Natural Gas Association of America (INGAA) on the 2002 proposed rule, where EPA indicated that 156 of 168 large engines listed in

the NOx SIP Call Inventory that have SIC codes associated with the NG transmission industry are LB engines (with the exception that the other 12 engines are no longer in service, are owned by a company not included in the industry database, or are duplicates). INGAA recommended that EPA assume all large NG stationary engines in the inventory are LB. (EPA 2003).

One prominent use of large Reciprocating Internal Combustion Engines (RICE) is to drive NG pipeline compressor stations; almost all engines affected by the NOx SIP Call Phase 2 rule in IL (except for 3 engines) are used to compress NG at NG pipeline stations. (IEPA 2007)

A 2009 ERLE study cited in this reference indicated there are 5,600 engines on the NG pipeline systems with a collective rating of 9,150,000 hp. That study further indicated that approximately 80 percent of the rated output was low speed 2S, low speed 4S integral engines and diesel medium speed engines converted to spark ignition (SI). Of these 80 percent of engines, 78 percent were 2S LB, 14 percent were 4S LB, and 8 percent were 4S RB. (On a rated horsepower basis, 80 percent was 2S LB, 15 percent was 4S LB, and 5 percent 4S RB) (p. 16). [On an overall basis, compared to the full 9,150,000 hp collective rating, 2S LB would be roughly 62%, 4S LB would be roughly 11%, and 4S RB would be roughly 6% of the overall rating/engines. So 73% would be LB, 6% would be RB, and the balance is not known.] (OTC 2012)

Engine Type	No. Engines, %	Horsepower, %
2S LB	78	80
4S LB	14	15
4S RB	8	5

The DE 2012 document cited a 2003 Pipeline Research Council International (PRCI) document that identified 5,686 engines: 71% are LB and 29% are RB (based on dropping the turbine numbers in the table below) (p.19). (DE 2012) [These data may be repeated in OTC 2012, as it looks fairly similar to the 2009 ERLE study data cited above from OTC 2012.]

2003 Pipeline Research Council International Data (PRCI)

Unit Type	U.S. Total Units (%)	Avg hp
2S LB	2,955 (44%)	2,113
4S LB	1,059 (16%)	1,844
RB	1,672 (25%)	589
Turbine	1,016 (15%)	6,121

Energy Information Agency (EIA) data cited in the OTC 2012 reference indicated there were 1201 NG mainline compressor stations in the U.S. in 2006, with combined rating of 16,800,000 hp. Between 2007 and 2010, the Federal Energy Regulation Commission (FERC) approved new compressor stations or upgrades to existing compressor facilities that were expected to add 2,600,000 hp (p. 16). (OTC 2012)

The Kansas State University (KSU) 2011 document included a database on 4,729 engines used in Exploration and Production (E&P) at major sources. LB engines accounted for 66 percent of engines (17 percent are 2S and 49 percent are 4S), and RB engines accounted for 34 percent. LB outnumbered RB among engines included in the database; because many engines rating less than 100 hp are not included, and because the majority of the smaller units are 4S RB, RB are actually underrepresented in the database. A listing of the engines (manufacturer and model), air to fuel (A/F) ratio type, cycle, and horsepower are included in Appendix I of the KSU 2011 document. The database was not meant to collect every single engine in use but rather to provide a frequency distribution of engines. The data was pulled from multiple sources, including the State of Wyoming Engine Inventory Database, EPA ICCR Database, GTI/PRCI Engine and Turbine Database, and Database of Colorado and New Mexico Engines (from Universal Compression). The engine database likely includes only permitted engines, and lower-hp engines are underrepresented in the database. (pp. 5-7) (KSU 2011)

The EDF 2008 reference indicated most engines in Barnett Shale area of Texas are 100 to 500 hp but some large engines of 1000+ hp are also used. (EDF 2008)

The EDF 2008 reference indicated that the TCEQ Point Source Emissions Inventory (PSEI) does not include a substantial fraction of compressor engine emissions. Most of the missing engines in the DFW NAA were units with emissions below the reporting thresholds, but the combined emissions from large numbers of these engines can be substantial (pp. 13-14). The 2007 DFW Engine survey indicated there were approximately 680,000 hp of installed engine capacity in DFW NAA not previously reported to the TCEQ PSEI (p. 14). The report also estimated that there is approximately 132,000 hp of engines in Attainment Area (AA) counties within the Barnett Shale that don't report to PSEI (non-PSEI) (p. 14). The LB and RB engine data from the 2007 DFW Engine Survey for the DFW NAA is provided in the table below. In this survey, there seem to be fairly even numbers of LB (51%) and RB (49%) engines in the >500 hp category, and there seems to be fairly even horsepower capacity for the LB and RB engines. For smaller engines that are <500 hp, there are significantly more RB engines (736

engines, or 96%) than LB engines (27 engines, or 4%). In addition, for the smaller engines <500 hp, the horsepower capacity for RB represents 15% and for LB is <1%. (EDF 2008)

Installed Engine Capacity in 2007 DFW Engine Survey by Engine Type and Size, in DFW NAA (EDF 2008)

Engine Type	Engine Size, hp	Number of Engines	Percent of Engines, %	Typical Size, hp	Installed Capacity, hp	Percent of Installed Capacity, %
RB	<50	12	1.03%	50	585	0.086%
RB	50–500	724	62%	140	101,000	15%
RB	>500	200	17%	1,400	280,000	41%
LB	<500	27	2.3%	185	4,940	0.72%
LB	>500	206	18%	1,425	294,000	44%

The EDF 2008 reference looked at all of the compressor engines in the Barnett Shale region, including both the engines located within the DFW NAA and the engines in the DFW AA (including those larger engines that report to the PSEI and those non-PSEI engines). New TCEQ rules became effective in 2009 to reduce NO_x from the subset of engines located in the DFW NAA that typically are not reported to the PSEI (due to their small size) for major sources (p. 25). Engines that are located outside the DFW NAA are not subject to the 2009 rule. As shown in the table below, a 50% reduction of emissions from 2007 to 2009 was estimated in DFW NAA, taking into account the growth, regulation affect, and NSCR installations. For AA engines, emissions will increase from 2007 to 2009 due to growth and the fact that no regulation applies (these engines not subject to 2009 engine regulation) (p. 19). (EDF 2008)

NO_x Emissions from Compressor Engines in Barnett Shale of Texas (EDF 2008)

Area	2007 NO _x Emissions, tpd	2009 NO _x Emissions, tpd
DFW NAA engines	32	16
AA engines	20	31
Barnett Shale engines, total	52	47

The reference then looked at emission reductions for extending the 2009 rule to all engines in the Barnett Shale (including those in the AA). By extending the 2009 engine rule,

NOx emissions from AA engines would drop by approximately 6.5 tpd (p.25) (this approach reduces emissions from a large number of engines, in particular RB engines between 50 to 500 hp). (EDF 2008)

The ETCG 2013 reference indicated that analysis of test reports at the TCEQ Tyler office showed 68 compressor engines: 9 engines (13%) <240 hp and 59 engines (87%) ≥240 hp (and 69% of all engines ≥500 hp) (p.11). (A graph showing the distribution of the hp for all 68 engines is shown on p.12 of the reference document.) (ETCG 2013)

The ETCG 2013 reference discussed TCEQ Barnett Shale Special Inventory (Phase I) survey data. The table below is a summary of the engine horsepower distribution. (A graph showing the distribution of NG engines in the Barnett Shale region is shown in Figure 5-1 on p. 21 of the reference document.) The majority of engines in the Barnett Shale are RB and are <240 hp, see the two tables below. This data set shows that smaller hp engines are predominantly RB, with 2,089 engines <240 hp are RB (95%) and 104 engines (5%) are LB. For engines >240 hp, 327 engines (59%) are LB and 230 engines (41%) are RB.

2009 Equipment Inventory of Stationary NG Engines by Horsepower for Barnett Shale Region. (ETCG 2013)

Engine Size	Total Engines	Percent of Total Engines	Engine Type, RB or LB	Number of Engines	Percent of Each Size Category
0 to 50 hp	317	12%	RB	302	95%
			LB	15	4.7%
50 to 240 hp	1,876	68%	RB	1,787	95%
			LB	89	4.7%
>240 hp	557	20%	RB	230	41%
			LB	327	59%

Barnett Shale Special Inventory Phase I Equipment Survey Data on Stationary Gas-Fired Engines for 2009. (ETCG 2013)

Engine counts		
<240 hp	≥240 hp	Total
RB and LB		
2,193	557	2,750
RB only		
2,089	230	2,319
LB only		
104	327	431

The CO DPHE reference indicates that large NG RICE represent 16% of the statewide point source NOx emissions (16,199 tpy of 101,818 tpy) and 73% of the ICE NOx emissions (16,199 tpy of 22,210 tpy) (p. 1). (CO DPHE)

Example Emissions Estimates: It is difficult to draw conclusions for the emissions from LB versus RB from the data provided. However, some assumptions could be made to help draw conclusions for the defined scenario. If assume that the total capacity between LB and RB in the ERLE study is more representative of the total reporting population than the 50–50 split in the EDF study; assume that operating hours are similarly distributed for both LB and RB; and if the EFs tend to be higher for LB than for RB engines, then it is likely that 90% plus of the total emissions are from LB.

References

- (CARB 2001). *Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines*. California Environmental Protection Agency, Air Resources Board, Stationary Source Division, Emissions Assessment Branch, Process Evaluation Section. November 2001.
- (IEPA 2007). Technical Support Document for Controlling NOx Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines. AQPSTR 07-01. Illinois Environmental Protection Agency, Air Quality Planning Section, Division of Air Pollution Control, Bureau of Air. March 19, 2007.
- (EPA 2003). Stationary Reciprocating Internal Combustion Engines: Technical Support Document for NOx SIP Call. U.S. Environmental Protection Agency. D. Grano and B. Neuffer. October 2003.

- (EDF 2008). *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost Effective Improvements*. Conducted by Department of Environmental and Civil Engineering, Southern Methodist University, for Environmental Defense Fund. Peer-Review Draft. September 30, 2008.
- (KSU 2011). *Final Report: Cost-Effective Reciprocating Engine Emissions Controls and Monitoring for E&P Field and Gathering Engines*. K. Hohn and S. Nuss-Warren, Kansas State University. November 2011.
- (OTC 2012). *Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions. Final*. October 17, 2012. [This document focuses on Offshore Gulf of Mexico, Rocky Mountains, Southwest, and Mid-Continent areas.]
- (ETCG 2013). *Gas Compressor Engine Study for Northeast Texas, for East Texas Council of Governments*. Prepared by ENVIRON International Corporation, for East Texas Council of Governments. June 2013.
- (CO DPHE). *Reciprocating Internal Combustion Engine (RICE) Source Category, Reasonable Progress Evaluation for RICE Source Category*. Colorado Department of Public Health and Environment—Air Pollution Control Division.

EPA Question 3: What is the effect of NO_x SIP call controls on RICE in NO_x SIP call states? That is, what percent reduction and types of controls have gone into place in states affected by the NO_x SIP call?

Notes for Question 3

The applicability, reduction achieved, and cost for RICE NO_x controls are often engine specific and highly variable. (DE 2012) (OTC 2012)

Common NO_x control techniques are provided in the table below, along with NO_x emission reductions achievable. (References from other areas outside of the NO_x SIP call states also provided details on controls and emissions reductions achieved by these controls and are included in the table.)

Effectiveness of Combustion Control Technologies and Add-On Controls

Control Technique	(OTC 2012)	(KSU 2011)	(CARB 2001)	(CO DPHE)
2 Stroke, LB				
Improved combustion air flow, Turbocharger	(p. 18, 31): up to 75%	Up to 90%; 0.5 to 2 g/bhp-hr (increases fuel economy; may increase CO) (p. 9)	—	—
Retard ignition timing	(p. 54): diesel, 10% (reduces engine efficiency; increases PM)	Up to 10% (increase fuel economy; may increase CO) (p. 9)	(p. B-7,8): 15 to 30% (increases fuel consumption; increases VOC, HAP)	20% (pp. 5-7); \$310 to \$2,000/ton (p. 8)
Improved air fuel mixing, High Pressure Fuel Injection	(p. 18, 31): up to 90%	—	—	—
Advanced In-cylinder mixing	—	30 to 70% (p. 11)	—	—
Precombustion chamber (PCC) ignition system	(p. 19, 31-32): up to 90%	1 g/bhp-hr (p. 10)	—	—
Micro Precombustion chamber (MPCC), hybrid of High energy Ignition system and PCC	—	2 to 4 g/bhp-hr (p. 10)	—	—
Screw-in PCC	—	1 g/bhp-hr (p. 10)	—	—
Autobalance cylinders	(p. 23): not provided	—	—	—

(continued)

Effectiveness of Combustion Control Technologies and Add-On Controls (continued)

Control Technique	(OTC 2012)	(KSU 2011)	(CARB 2001)	(CO DPHE)
2 Stroke, LB (cont.)				
Air to Fuel Ratio Controller (AFRC)	(p. 19, 32): not provided	Not provided; use in combo with Increased air flow, or postcombustion Catalyst; a few thousand \$ for small engine to \$30K for larger engines (p. 12).	(p. B-8): not provided (fuel consumption penalty of 3%; may increase CO, VOC)	5 to 30% (pp. 5-7); \$320 to \$8,300/ton (p. 7)
Combustion modifications, Layered Combustion controls	(p. 25): 60 to 90%; range of 0.5 to 3 g/bhp-hr	—	—	—
4 stroke, LB				
EGR and NSCR	(p. 32): (emissions lower than SCR) ^a	—	—	—
Combustion modifications, Layered Combustion controls	(p. 38): 90%; range of 0.5 to 2 g/bhp-hr	—	—	—
Engines (general) or LB				
High energy ignition system (HEIS)	(p. 18, 31, 44): 10%	2.5 to 3 g/bhp-hr (pp. 9-10)	(p. B-12): 200 ppm NOx	—
Low emission combustion (LEC)/precombustion chamber retrofit (PCC) [also applicable to RB]	—	—	(p. B-10): 80% (may increase VOC, CO)	—
Turbocharging/supercharging, and Aftercooling	(p. 18): Up to 75%	—	(p. B-13): 3 to 35% for Aftercooling (may reduce VOC, CO; increases engine efficiency, power rating)	—
EGR	(p. 55): diesel, >40% (loss of fuel efficiency; loss of engine output)	Still under development for NG engines; not cost effective at this time (p. 11).	(p. B-14): 30% (reduces engine peak power; reduces fuel efficiency by 2 to 12%)	—
Ignition system improvement	—	—	(p. B-11-2): not provided (may increase VOC, CO)	—

(continued)

Effectiveness of Combustion Control Technologies and Add-On Controls (continued)

Control Technique	(OTC 2012)	(KSU 2011)	(CARB 2001)	(CO DPHE)
Engines (general) or LB (cont.)				
Homogeneous charge compression ignition (HCCI), combines best features of SI and CI engines	—	Still in R&D phase, no reduction or cost info available (reduces PM; high efficiency) (p. 11-12).	—	—
Fuel switching, Hydrogen/NG blended fuel	—	40 to 50% (p. 12) Still under development, no cost info available; use of H ₂ blend removes need for PCC; H ₂ fuel would need to be available in the field.	—	—
Selective Catalytic Reduction (SCR)	(p. 19, 32, 55): 50 to 95% (reduces THC, CO)	80 to 90% (can release NH ₃) (p. 13)	(p. B-23): >80%	80 to 90% (pp. 5-7); \$430 to \$4,900/ton (p. 9)
Lean-NO _x catalysts	(p. 55): diesel, 10 to 50%	Up to 80% (reduces CO, HC by 60%; reduces fuel economy by 3%) (p. 14)	(p. B-24): diesel, 25 to 50% (increases fuel consumption; may increase VOC, PM)	—
NO _x Tech	—	—	(p. B-25): 80 to 90%; (decreases CO, VOC, PM by 80%; fuel penalty 5 to 10%)	—
Lean NO _x traps	(p. 55): diesel, up to 90%	—	—	—
NO _x Adsorber Technology (SCONOX)	—	—	(p. B-27): >90% on diesel engine <100 hp; [2 ppmv on NG turbine]	—
Selective noncatalytic reduction (SNCR) [also applicable to RB]	—	—	—	50 to 95% (pp. 5-7)

(continued)

Effectiveness of Combustion Control Technologies and Add-On Controls (continued)

Control Technique	(OTC 2012)	(KSU 2011)	(CARB 2001)	(CO DPHE)
Engines (general) or LB (cont.)				
Fuel switching, methanol	—	—	(p. B-16): 30% for conversion from NG to methanol (can generate formaldehyde emissions)	—
Hybrid system, modification of dual bed NSCR system	—	—	(p. B-22): 3 to 4 ppm NOx	—
Use of electric motors in place of combustion engines	—	—	(p. B-27): >60%	60 to 100% (pp. 5-7); \$100 to \$4,700/ton [not include full costs] (p. 9)
RB				
Nonselective catalytic reduction (NSCR) plus AFRC	(p. 45, 49-51): 90 to 99% (reduces CO, VOC)	>90%, < 1 g/bhp-hr (reduces CO, HC) (p. 13)	(p. B-19-20): >90% (reduces CO >80%; reduces CO>50%; increases fuel consumption)	80 to 90% (pp. 5-7); Capital cost is \$35,000; O&M is \$6,000; Annualized capital is \$4,851; TAC is \$10,851; \$571/ton (p. 8)
Convert RB to LB	(p. 45): not provided	—	—	—
EGR	(p. 49): up to 80% (increase power output by 10%; decrease fuel consumption by 7%)	—	—	—
Pre-stratified charge (converts RB to LB)	—	For 4S, RB, 2 g/bhp-hr (may de-rate engine power by 20%; costs significant) (p. 11)	(p. B-15): >80% (improved fuel efficiency)	—

^aSome industry literature suggests that some particular 4S RB SI reciprocating engines can be converted to LB configurations with the accompanying LB engine NOx reduction capabilities. One vendor indicates that conversion to a LB configuration and the use of exhaust gas recirculation (EGR) delivers the advantages of a LB engine's efficiency and the RB engine's capability of utilizing NSCR for NOx control. The ability to convert a RB engine to a LB configuration is highly unit specific and does appear to have had widespread application in industry (p. 45). (OTC 2012)

Illinois: IEPA projected 2007 NOx emissions from 28 engines subject to the NOx SIP call to be 6,618 ton/season. NOx emission reductions from these sources were estimated to be 5,422 ton/season, and controlled NOx emissions levels were estimated to be 1,196 ton/season. (So baseline emissions were estimated to be 6,618 ton/season and controlled emissions were estimated to be 1,196 ton/season.) (IEPA 2007)

IEPA 2002 base year emissions inventory was 23,347 tpy NOx emitted from RICE and turbines, or approximately 8.4 percent of total point source NOx emissions (277,899 tpy NOx emissions from all point sources in Illinois) (p. 12). (IEPA 2007)

In addition to the NOx SIP Call requirements, IEPA also included additional units in its NOx regulation. NOx SIP Call units were to comply by May 2007, and additional units in NAA and AA were to comply in 2009, 2011, and 2012 (p. 51). The IL regulation will potentially affect 202 RICE engines and 36 turbines and reduce NOx emissions by 5,422 ton/season in 2007 ozone control season (p. 10). (IEPA 2007) [Full implementation of the IL regulation in 2012, to include additional units in NAA and AA counties down to the 500 hp size [28 NOx SIP Call units plus an additional 246 engines], was projected to reduce NOx emissions statewide by 17,082 tpy and 7,206 ton/season, which is 65 percent reduction on an annual basis and 55 percent reduction in O₃ season emissions (pp. 11 and 56). Uncontrolled NOx emissions in 2012 were projected to be 21,532 tpy and 9,134 ton/season, for those units included under the full implementation of the rule (p. 56). (IEPA 2007)]

Other Available Information

Additional RB control technologies and data are available in the OTC 2012.

Additional Diesel control technologies and data are available in OTC 2012.

References

(CARB 2001). *Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines*. California Environmental Protection Agency, Air Resources Board, Stationary Source Division, Emissions Assessment Branch, Process Evaluation Section. November 2001.

- (IEPA 2007). *Technical Support Document for Controlling NO_x Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines*. AQPSTR 07-01. Illinois Environmental Protection Agency, Air Quality Planning Section, Division of Air Pollution Control, Bureau of Air. March 19, 2007.
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- (CO DPHE). *Reciprocating Internal Combustion Engine (RICE) Source Category, Reasonable Progress Evaluation for RICE Source Category*. Colorado Department of Public Health and Environment – Air Pollution Control Division.

EPA Question 4: What are typical or realistic baseline and controlled NO_x emissions factors (grams/hp-hr) for RICE in the OTC states?

Notes for Question 4

NO_x control requirements for several of the Ozone Transport Commission (OTC) states were provided for Connecticut, New Jersey, New York, and Rhode Island, based on a 1994 STAPPA/ALAPCO document (p. 45). (IEPA 2007) These could potentially be used as maximum EF for RICE units. NO_x control requirements are listed in the following table.

NO_x Control Requirements for RICE in Some OTC States and Other States

State	Covered	NO _x Control Level	Reference
Connecticut	≥3 MMBtu/hr (1175 hp)	Liquid-fired, CI: 8 g/bhp-hr (584 ppm)	IEPA 2007
New York	RACT for Major Facilities of NO _x , Severe O ₃ NAA ≥200 hp and Rest of state ≥400 hp	- Thru March 31, 2005, NG, RICE, LB: 3 g/bhp-hr (220 ppm) - After April 1, 2005, LB: 1.5 g/bhp-hr (110 ppm) - Thru March 31, 2005, Liquid-fired, CI: 9 g/bhp-hr (657 ppm) - After April 1, 2005: 2.3 g/bhp-hr (168 ppm)	OTC 2012, DE 2012, IEPA 2007
New York (RACT)	Major facilities >25 tpy, NYC and Lower Orange Co: ≥200 kW Rest of state, major facilities >100 tpy: ≥400 kW	- NG: 1.5 g/bhp-hr - Landfill or digester gas: 2.0 g/bhp-hr	
New Jersey		- NG, LB, ≥500 hp: 2.5 g/bhp-hr (182 ppm) - Liquid-fired, CI, ≥500 hp: 8 g/bhp-hr (584 ppm)	IEPA 2007
New Jersey (RACT)	≥148 kW Group of 2 or more engines, each at ≥37 to <148 kW, but total combined power ≥148 kW	- Gas, LB: 1.5 g/bhp-hr, or 80% reduction - Gas, RB: 1.5 g/bhp-hr	
New Jersey (RACT)	≥37 kW	- Commenced on or after March 7, 2007: 0.9 g/bhp-hr - Modified on or after March 7, 2007: 0.9 g/bhp-hr, or 90% reduction	
Maryland	NG pipeline engines with >15% capacity factor	NA	IEPA 2007
Other States and Areas			
Illinois	NA	3 g/bhp-hr (210 ppm)	NA

(continued)

NOx Control Requirements for RICE in Some OTC States and Other States (continued)

State	Covered	NOx Control Level	Reference
Other States and Areas (cont.)			
SJVAPCD (amended 2011Aug18)	Rule 4702 ICE, SI and CI, nameplate rating ≥25 hp	▪ 2S, LB, NG, <100 hp: 75 ppmvd ▪ LB limited use or Gas compression: 65 ppmvd ▪ LB, all others: 11 ppmvd	OTC 2012
Texas	Oil & Gas Handling and Production Facilities	▪ 2S, SI, LB, ≥500 hp: – Mfg before 9/23/1982: 8 g/bhp-hr – Mfg before 6/18/1992, <825 hp: 8 g/bhp-hr – Mfg btwn 9/23/1982 and 6/18/1992, >825hp: 5 g/bhp-hr – Mfg btwn 6/18/1992 and 6/1/2010: 2 g/bhp-hr (except 5 g/bhp-hr at reduced speed and torque 80-100%) – Mfg after 6/1/2010: 1 g/bhp-hr	OTC 2012
Texas	Oil & Gas Handling and Production Facilities	▪ 4S, SI, LB: – Mfg before 9/23/1982, ≥500hp: 5 g/bhp-hr (except 8 g/bhp-hr at reduced speed and torque 80-100%) – Mfg before 6/18/1992, <825 hp: 5 g/bhp-hr (except 8 g/bhp-hr at reduced speed and torque 80-100%) – Mfg btwn 9/23/1982 and 6/18/1992, >825hp: 5 g/bhp-hr – Mfg btwn 6/18/1992 and 6/1/2010, ≥500hp: 2 g/bhp-hr (except 5 g/bhp-hr at reduced speed and torque 80-100%) – Mfg after 6/1/2010, ≥500hp: 1 g/bhp-hr ▪ After 1/1/2030, no 4S LB SI engine NOx emissions shall exceed 2 g/bhp-hr regardless of manufacture date.	OTC 2012
Texas	Oil & Gas Handling and Production Facilities	▪ 4S SI, LB, <500hp: ▪ Mfg before 7/1/2008: 2 g/bhp-hr ▪ After 1/1/2030: no 4S LB SI engine NOx emissions shall exceed 2 g/bhp-hr regardless of manufacture date.	OTC 2012
Texas (NAA major sources)	RACT, Major ICI, O3 NAA, Beaumont-Port Arthur O3 NAA Major sources	▪ NG, SI, RICE, LB ≥300 hp: 3 g/bhp-hr ▪ NG, SI, RICE, RB, ≥300 hp: 2 g/bhp-hr	OTC 2012, DE 2012
Texas (NAA minor sources)	Combustion Control at Minor Sources in O3 NAA, Houston- Galveston-Brazoria	▪ NG, RICE, >50 hp: 0.5 g/bhp-hr	DE 2012, ETCG 2013
Texas	O3 NAA, Dallas Ft. Worth	▪ RB, >50 hp: 0.5 g/hp-hr ▪ LB, >50 hp: – Installed or moved before June 2007: 0.7 g/hp-hr – Installed or moved after June 2007: 0.5 g/hp-hr	EDF 2008; ETCG 2013

(continued)

NOx Control Requirements for RICE in Some OTC States and Other States (continued)

State	Covered	NOx Control Level	Reference
Other States and Areas (cont.)			
Texas	East Texas Combustion Rule (existing engines comply by March 1, 2010; new engines comply at startup.)	▪ RB, NG, RICE, 240 to 500 hp: 1 g/hp-hr ▪ RB, NG, RICE, ≥500 hp: 0.5 g/hp-hr ▪ RB, Landfill gas, RICE, ≥500 hp: 0.6 g/hp-hr	ETCG 2013
Colorado	Regulation 7, RICE, LB, NG, New, modified, relocated	▪ After July 1, 2007, ≥500 hp: 2 g/bhp-hr ▪ After July 1, 2010, ≥500 hp: 1 g/bhp-hr ▪ After January 1, 2008, 100 to 500 hp: 2 g/bhp-hr ▪ After January 1, 2011, 100 to 500 hp: 1 g/bhp-hr	OTC 2012; CO DPHE
USEPA Part 60, subpart JJJJ (NSPS) (final 2008Jan18)	NG, SI, ICE	▪ Mfg after 7/1/2008, ≤25 hp, Class I: 11.0 g/hp-hr of NMHC + NOx combined ▪ Mfg after 7/1/2008, ≤25 hp, Class I-B: 27.6 g/hp-hr of NMHC + NOx combined ▪ Mfg after 7/1/2008, ≤25 hp, Class II: 8.4 g/hp-hr of NMHC + NOx combined ▪ Mfg after 7/1/2008, 25 to 100 hp: 2.8 g/hp-hr of HC + NOx combined	ETGC 2013
USEPA Part 60, subpart JJJJ (NSPS) (final 2008Jan18)	SI, NG and SI, LB, LPG, 100 to 500 hp	▪ Mfg after 7/1/2008: 2 g/bhp-hr ▪ Mfg after 1/1/2011: 1 g/bhp-hr	ETCG 2013
USEPA Part 60, subpart JJJJ (NSPS) (final 2008Jan18)	NG and LPG, SI, LB, 500 to 1350 hp	▪ Mfg after 7/1/2008: 2 g/bhp-hr ▪ Mfg after 7/1/2010: 1 g/bhp-hr	OTC 2012
USEPA Part 60, subpart JJJJ (NSPS) (final 2008Jan18)	SI, NG and SI, LB, LPG (except LB 500 to 1350 hp)	▪ Mfg after 7/1/2007: 2 g/bhp-hr	ETCG 2013

NOx Control Requirements for RICE in Local Areas.

State or Area	Criteria	NOx control level	Reference
SCAQMD (July 2010)	Rule 1110.2 Emissions from Gaseous and Liquid Fueled Engines	▪ ≥ 500 hp: 0.5 g/bhp-hr (36 ppmvd) ▪ < 500 hp: 0.6 g/bhp-hr (45 ppmvd) ▪ After July 1, 2010, ≥ 500 hp: 0.15 g/bhp-hr (11 ppmvd) ▪ After July 1, 2010, < 500 hp: 0.6 g/bhp-hr (45 ppmvd) ▪ After July 1, 2011, All: 0.15 g/bhp-hr (11 ppmvd)	OTC 2012

For engines with unknown pre-rule emissions, NOx emissions were assumed to be 16.4 g/bhp-hr for 2S and 18.9 g/bhp-hr for 4S. (DE 2012)

A list of Stack test results for engines in PA that are > 500 hp are given in Appendix A, Table 3 of the PA DEP 2013 reference (p. 53). (PA DEP 2013) [Capital] costs for NSCR, RB ranged from \$10 to \$12/bhp. (p. 9) NSCR, RB ranged from \$10 to \$15/bhp (slightly different value given here). (p. 16) (MECA 1997)

IC Engine Typical Emissions Levels (MECA 1997)

Engine Type	Lambda (Actual A/F ratio to Stoichiometric A/F ratio)	Mode	NOx, g/bhp-hr
NG	0.98	Rich	8.3
	0.99	Rich	11.0
	1.06	Lean	18.0
	1.74	Lean	0.7
Diesel	1.6–3.2	Lean	11.6
Dual Fuel	1.6–1.9	Lean	4.1

For RB, CARB 2001 document has Costs for NSCR w/o AFRC achieving 96% reduction. Capital costs ranged from \$11,000 to \$44,000; Annual costs ranged from \$8,200 to \$18,000; and cost effectiveness ranged from \$2,100/ton to \$300/ton NOx reduction (p. V-2 to V-3). (CARB 2001)

For RB, CARB 2001 document has Costs for Pre-stratified Charge, achieving 80% reduction. Capital costs ranged from \$10,000 to \$47,000; Annual costs ranged from \$2,700 to

\$11,000; and cost effectiveness ranged from \$800/ton to \$200/ton NOx reduction (pp. V-2 to V-3). (CARB 2001)

CARB 2001 document has costs for Ignition Timing Retard (ITR), although the description of the combustion technology indicates it is less popular on Stationary engines than mobile source engines (pp. V-2, B-7 to B-8). (CARB 2001)

The EDF 2008 reference provided NOx EF for engines in the Bartlett Shale region. The document notes that extending the 2009 engine rules in Barnett Shale to counties outside the DFW NAA would likely result in many engine operators installing NSCR on RB engines. NSCR costs were cited as follows: \$330/ton (IEPA 2007); \$92 to \$105/ton (EPA 2006); and \$112 to \$183/ton (northeast Texas 2005 report). Another control technique reviewed in this report included replacement of compressor engines with electric motors. There are multiple compressors driven by electric motors throughout Texas (p. 26). Use of electric motors instead of gas-fired engines eliminates combustion emissions (p. 27). The costs are time and site specific, based on the cost of electricity, cost of NG, hours of operation per year, number of compressors, size of compressor, etc. (EDF 2008)

NOx Emission Factors for Engines Identified in DFW 2007 Engine Survey (EDF 2008)

2007 EF			2009 EF		
Engine Type	Engine Size, hp	NOx, g/hp-hr	Engine Type	Engine Size, hp	NOx, g/hp-hr
RB	<50	13.6	RB	<50	13.6
RB	50–500	13.6	RB	50–500	0.5
RB	>500	0.9	RB	>500	0.5
LB	<500	6.2	LB, installed or moved before June 2007	<500	0.62
LB	>500	0.9	LB, installed or moved after June 2007,	<500	0.5
—	—	—	LB, installed or moved before June 2007	>500	0.7
—	—	—	LB, installed or moved after June 2007	>500	0.5

References

- (MECA 1997). *Emission Control Technology for Stationary Internal Combustion Engines: Status Report*. Manufacturers of Emission Controls Association (MECA). July 1997.
- (CARB 2001). *Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines*. California Environmental Protection Agency, Air Resources Board, Stationary Source Division, Emissions Assessment Branch, Process Evaluation Section. November 2001.
- (IEPA 2007). *Technical Support Document for Controlling NO_x Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines*. AQPSTR 07-01. Illinois Environmental Protection Agency, Air Quality Planning Section, Division of Air Pollution Control, Bureau of Air. March 19, 2007.
- (EDF 2008). *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost Effective Improvements*. Conducted by Department of Environmental and Civil Engineering, Southern Methodist University, for Environmental Defense Fund. Peer-Review Draft. September 30, 2008.
- (DE 2012) *Background Information, Oil and Gas Sector, Significant Sources of NO_x Emissions*. Delaware Department of Natural Resources and Environmental Quality.
- (OTC 2012). *Technical Information Oil and Gas Sector, Significant Stationary Sources of NO_x Emissions*. Final. October 17, 2012.
- PA DEP 2013. Technical Support Document General Permit GP-5. Pennsylvania Department of Environmental Protection, Bureau of Air Quality. January 31, 2013.
- (ETCG 2013). *Gas Compressor Engine Study for Northeast Texas, for East Texas Council of Governments*. Prepared by ENVIRON International Corporation, for East Texas Council of Governments. June 2013.
- (CO DPHE). *Reciprocating Internal Combustion Engine (RICE) Source Category, Reasonable Progress Evaluation for RICE Source Category*. Colorado Department of Public Health and Environment—Air Pollution Control Division.

EPA Question 5: Using FERC data or other data sources, what is the relationship between RICE model and age, and emissions (both for baseline and with controls)? In particular, what is the relationship for RICE built before the imposition of the SI (spark ignition, natural gas-fired) RICE NSPS in 2007?

Notes for Question 5

The DE 2012 reference stated that many of the installed mainline NG compressors are of the age (in excess of 40 years old) to have pre-dated modern original equipment manufacturer (OEM) installed NOx emission controls and otherwise applicable new source performance standards (NSPS). There is little information on the number of units that may have undergone NOx modifications as a result of federal or State rules and regulations. The reference cited a 2003 Pipeline Research Council International (PRCI) document that identified 5,686 engines: 71% are LB and 29% are RB (based on dropping the turbine numbers in the table below). The average age for each unit type is shown in the following table. [These data are repeated in OTC 2012.] [Based on these data, it is estimated that the LB and RB engines are 37 years old on average (based on dropping the turbine numbers in the table below).] (p. 19) (DE 2012)

2003 Pipeline Research Council International Data (PRCI)

Unit Type	U.S Total Units (%)	Average Age (as of 2003)	Avg hp
2S LB	2,955 (44%)	42	2,113
4S LB	1,059 (16%)	33	1,844
RB	1,672 (25%)	32	589
Turbine	1,016 (15%)	24	6,121

The OTC 2012 reference indicated that many of the reciprocating engines driving mainline NG compressors are in excess of 40 years old, pre-dating any applicable modern OEM installed NOx emission control and any otherwise applicable NSPS NOx controls (p. 16). (OTC 2012)

The DE 2012 reference discussed a 2005 study conducted for NG field gathering engines in Eastern Texas; the study was able to determine the age only for a very small portion of the engines, and the engine age ranged from 2 to 25 years. The output ratings of engines in the study ranged from 26 to 1478 hp, with the majority rated between 50 and 200 hp (p. 12). (DE 2012)

The DE 2012 reference indicated they reviewed MARAMA's 2007 Point Source Inventory and 2007 FERC data. The 2007 FERC data are provided as Attachment III to the

reference. The two sets of data did not match: 2007 MARAMA data indicated 107 compressor facilities, and 2007 FERC data indicated 150 compressor facilities. The reviewed databases did not provide any information regarding NOx emission rates (g/bhp-hr, ppmvd). NOx emission rates were obtained for a small number of prime movers, through operating permits: 2SLB range from 1 to 13.3 g/bhp-hr; 4SLB range from 0.5 to 6 g/bhp-hr; and 4SRB were 3 g/bhp-hr. The data are not sufficient to estimate actual NOx emission rates and NOx reductions. Note that the FERC data addresses large entities, and smaller companies may not be required to report data to FERC. The 2007 OTC compressors from FERC are provided in the following table. (DE 2012)

State	No. Compressors	Total Rated hp
CT	10	35,300
MA	15	25,702
MD	17	52,250
ME	4	33,244
NJ	36	129,130
NY	120	359,487
PA	467	1,331,164
RI	6	29,170
VA (OTR area only)	22	49,390

The KSU 2011 reference discussed control technologies testing performed in the laboratory on a 1966 Ajax DP-115 (Lean Burn) that has none of the low emissions controls that are currently OEM standard. The published emission factor (EF) for this engine is 4.4 g/bhp-hr, and the emissions from actual testing were 4.69±0.18 g/bhp-hr (the Lab testing results are discussed on pp. 19-27). There is additional discussion of Field testing conducted on multiple LB engines with NOx emission control techniques, including (1) Increased air flow, and precombustion chamber (PCC) screw-in type, (2) PCC screw-in type and Upgraded turbocharger, (3) Integral PCC and high-output turbocharger (pp. 27-29). Discussion of Field testing conducted on two RB engines with NOx emission control techniques (p. 29). Integrated nonselective catalytic reduction (NSCR) with modeling and enhanced controller is also discussed. (KSU 2011).

References

(KSU 2011). *Final Report: Cost-Effective Reciprocating Engine Emissions Controls and Monitoring for E&P Field and Gathering Engines*. K. Hohn and S. Nuss-Warren, Kansas State University. November 2011.

(DE 2012) *Background Information, Oil and Gas Sector, Significant Sources of NO_x Emissions*. Delaware Department of Natural Resources and Environmental Quality.

(OTC 2012). *Technical Information Oil and Gas Sector, Significant Stationary Sources of NO_x Emissions. Final*. October 17, 2012.

Appendix A

EPA Question 6: What is the variability in NO_x emissions from RICE within each State, both for baseline and with controls?

Notes for Question 6

No data were found. [Likely a review of RICE SCCs in the NEI across states would be a useful exercise to see the relative levels of baseline and/or controlled NO_x emissions, however this exercise was not part of this task.]

Appendix A

To: US EPA OAQPS
From: SRA International, Inc.
Subject: Review of CoST Model Emission Reduction Estimates
Date: September 30, 2014

EPA uses the Control Strategy Tool (CoST) to estimate the emission reductions and engineering costs associated with control strategies applied to point, area, and mobile sources of air pollutant emissions to support the analyses of air pollution policies and regulations. CoST accomplishes this by matching control measures to emission sources using algorithms such as "maximum emissions reduction", "least cost", and "apply measures in series". There was a concern that the baseline inventory used by CoST did not completely account for emission control requirements already in place, and that the emission reductions were perhaps overestimated.

SRA reviewed the CoST results and made recommendations for changing the CoST control measure assignment and the estimated reductions for oxides of nitrogen (NOx). The recommendations were based on a review of source permits, state regulations, enforcement actions, and other available information. The analysis was conducted for a 24-state area in the eastern two-thirds of the U.S. The focus was on stationary point sources other than electric generating units (non-EGUs). The purpose of this memo is to document the data used and assumptions made in recommending changes to the CoST results, and to summarize the differences between the CoST results and the recommended changes.

The findings in this memo are based on review of CoST results for a 2018 emissions inventory projected from the 2011 National Emission Inventory (NEI). This work was in support of EPA's current Transport Rule efforts for implementing the 75 ppb ozone standard. If EPA considers establishing a tighter ozone standard in the future, it is likely that a more distant future year will be used and that some of the conclusions reached in this memo could change.

CoST DATA PROVIDED BY EPA

EPA provided SRA with the outputs from a CoST scenario that identified sources for which NOx controls were available at a cost-effectiveness level of less than \$10,000 per ton. The CoST outputs included source identifiers, control technology, baseline emissions and estimates of NOx emission reductions. The CoST results were divided into two groups. The first group included sources where CoST estimated NOx emission reductions of more than 100 tons per year. There were 547 sources in this group where CoST controls were initially applied. The second group included sources where CoST estimated emission reductions for sources whose 2018 projected emissions were greater than 25 tons/year, excluding those

with reductions greater than 100 tons/year. There were 1,280 sources in this group where CoST controls were initially applied.

Another contractor reviewed the CoST results for additional source categories, and their recommendations were merged with SRA's recommendations in the summary tables and maps that follow. The data used, assumptions made and results for IC engines are documented elsewhere¹.

REVIEW OF CoST RESULTS FOR THE GREATER THAN 100 TPY GROUP

Table 1 summarizes the source categories included in our analysis, the CoST recommendation for NO_x control, and the recommendation for changing the CoST control measure assignment and associated emission reduction estimates. Following Table 1, there is a discussion for each source group to provide more detail on the rationale for the recommended changes for each source group. Attachments 1 to 4 are tabular comparisons of the initial CoST emission reduction estimates and the recommended changes. All Attachments present the results in terms of tons per ozone season, simply estimated by assuming that ozone season emissions were equal to 5/12 of the annual emissions. Maps 1A and 1B graphically show the location of sources and the magnitude of the recommended emission reductions.

Table 1 – CoST Controls and Recommended Changes for Greater than 100 TPY Sources

Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
Ammonia – NG-fired Reformers	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled.
By-Product Coke Mfg; Oven Underfiring	Selective Non-Catalytic Reduction	Review of a source-specific NO _x RACT permit indicated that NO _x controls were technically or economically infeasible.
Cement Kilns	Biosolid Injection Technology	Disagreed with CoST recommendation based on concerns about biosolids availability and information from EPA's ISIS (Industrial Sector Integrated Solutions) Model; recommended SNCR for all sources, except those that already have SNCR due to NO _x SIP Call, NSR requirement, Consent Decree, or other state regulation.

¹ Update of NO_x Control Measure Data in the CoST Control Measures Database for Four Industrial Source Categories: Ammonia Reformers, NonEGU Combustion Turbines, Glass Manufacturing, and Lean Burn Reciprocating Internal Combustion Engines," prepared by Research Triangle Institute, July 2014.

Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
Cement Manufacturing - Dry	Selective Non-Catalytic Reduction	Agreed with CoST recommendation except when already controlled due to NOx SIP Call, NSR requirement, Consent Decree, or other state regulation.
Cement Manufacturing – Wet	Mid-kiln Firing	Disagreed with CoST recommendation based on information from EPA's ISIS Model; recommended SNCR for all sources, except those that already controlled
Coal Cleaning – Thermal Dryer	Low NOx Burner	Agreed with CoST recommendation
Comm/Inst Incinerators	Selective Non-Catalytic Reduction	Both sources are already controlled with SNCR
External Combustion Boilers, Elec Gen, Solid Waste	Selective Non-Catalytic Reduction	All 6 sources are already controlled with SNCR
Fluid Catalytic Cracking Units	Low NOx Burner and Flue Gas Recirculation	Nearly all FCCUs are already controlled due to the OECA global refinery consent decrees. There is one small refinery in West Texas that does not appear to be covered by a consent decree, so the CoST recommendation was accepted.
Glass Manufacturing – Container, Flat, Pressed	OXY-Firing	Disagreed with CoST recommendation. OXY-firing is not generally required under recent OECA consent decrees. More common control is oxygen-enriched air staging (OEAS). OXY-firing can only be implemented at the time of furnace rebuild, which is generally done every 10-15 years. Changed recommended control to OEAS with a 50% NOx reduction instead of OXY-firing at 85% NOx reduction, except for sources that already had NOx controls in place due to a consent decree, NSR requirement, or state regulation. Assumed that a furnace with a NOx emission limit of less than 4 lbs/ton of glass pulled was already reasonably controlled.
ICI Boilers – Coal/Cyclone	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled. LADCO/OTC also recommends SCR
ICI Boilers – Coal/Stoker	Selective Catalytic Reduction	Disagreed with CoST recommendation of SCR. CoST has \$2200/ton, which appears

Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
		very low for ICI boilers. Used LADCO/OTC recommendation of SNCR for Coal-Stokers with a 50% reduction, except for those sources where a permit or state regulation already required the source to be controlled.
ICI Boilers – Coal/Wall	Low NOx Burner and Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled. LADCO/OTC also recommends LNB/SCR
ICI Boilers – Gas, Natural Gas, Process Gas	Selective Catalytic Reduction	Disagreed with CoST recommendation of SCR. CoST has \$3456/ton, which appears very low for ICI boilers. Used LADCO/OTC recommendation of Low NOx Burners plus Flue Gas Recirculation for Gas-fire ICI boilers with a 60% reduction, except for those sources where a permit or state regulation already required the source to be controlled
Industrial Incinerators	Selective Non-Catalytic Reduction	Agreed with CoST recommendation of SNCR except for those sources where a permit or state regulation already required the source to be controlled.
Iron & Steel Mills – Reheating	Low NOx Burner and Flue Gas Recirculation	Agreed with CoST recommendation except for those sources where a permit or state regulation already required the source to be controlled.
Municipal Waste Combustors	Selective Non-Catalytic Reduction	Agreed with CoST recommendation of SNCR except for those sources where a permit or state regulation already required the source to be controlled.
Nitric Acid Manufacturing	Nonselective Catalytic Reduction	Agreed with CoST recommendation of NSCR except for those sources where a permit or state regulation already required the source to be controlled.
Petroleum Refinery Process Heaters	SCR-95%	Nearly all refineries are already controlled due to the OECA global refinery consent decrees, which generally require 40-60% reductions across all boilers/heaters that each company operates. Not possible at present to identify the individual boilers/heaters that actually have been controlled or are scheduled to be controlled due to confidentiality agreements between EPA and companies.

Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
Taconite Ore Processing – Induration – Coal or Gas	Selective Catalytic Reduction	Disagree with CoST recommendation of SCR. EPA Region V considers SCR/SNCR to be infeasible. Used Low NOx Burners at 70% reduction instead as reasonable control, except for those sources where a permit or state regulation already required the source to be controlled. .
Utility Boilers* – Coal/Wall	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled.
Utility Boilers* – Oil/Gas	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled.

The utility boilers included in the context of this report are non-IPM utility boilers. In the NEI, these units have an SCC of 1-01—xxx-xx (the SCC series generally used for electric generating units. However, the sources included in this analysis do not sell electricity to the grid.

Ammonia – NG-fired Reformers

There are 15 sources in this category. The CoST control technology was selective catalytic reduction (SCR) with a 90% reduction in NOx emissions. We determined that four of these sources were already controlled by either SCR or ultra-NOx burners and recommended no further control/reductions. For all other sources, we agreed with the CoST control and emission reduction estimate.

By-Product Coke Mfg; Oven Underfiring

There are 14 sources in this category. The CoST control technology was selective non-catalytic reduction (SNCR) with a 60% reduction in NOx emissions. We reviewed a detailed RACT analysis for a facility in Pennsylvania that determined that no controls were feasible. For all sources in this category, we recommended that no controls were feasible and thus no reductions were appropriate.

Cement Preheater/Precalciner Kilns

There are 36 sources in this category. The CoST control technology was biosolid injection technology with a 23% reduction in NOx emissions. We reviewed permits and consent decrees to identify those kilns that are already controlled. Several kilns are already controlled based on NOx SIP Call requirements that typically required low NOx burners, mid-kiln firing, or an approved alternative that resulted in a 30% reduction. Other kilns already had SNCR installed due to a consent decree, new source review requirement, or other state-level requirement.

EPA expressed a concern whether there was sufficient biosolids availability for use by the uncontrolled kilns. Also, EPA has done considerable research on cement kiln NO_x controls as part of its Industrial Sector Integrated Solutions (ISIS) project. EPA uses the ISIS-cement model help analyze policy options for various rulemakings. Based on the ISIS work, we recommended that low-NO_x burners and SNCR as the appropriate control for all types of kilns.

For uncontrolled kilns, we applied a 65% reduction in NO_x emissions. For kilns already controlled with low-NO_x burners or mid-kiln firing, we applied a 35% incremental reduction to account for the additional reductions from SNCR. For kilns already controlled with SNCR, we applied no additional emission reductions.

Cement Manufacturing - Dry Process

There are 20 sources in this category. The CoST control technology was SNCR with a 50% reduction in NO_x emissions. We reviewed permits and consent decrees to identify those kilns that are already controlled. Several kilns are already controlled based on NO_x SIP Call requirements that typically required low NO_x burners, mid-kiln firing, or an approved alternative that resulted in a 30% reduction. Other kilns already had SNCR installed due to a consent decree, new source review requirement, or other state-level requirement.

As discussed earlier, we recommended that low-NO_x burners and SNCR as the appropriate control for all types of kilns based on the ISIS work. For uncontrolled kilns, we applied a 65% reduction in NO_x emissions. For kilns already controlled with low-NO_x burners or mid-kiln firing, we applied a 35% incremental reduction to account for the additional reductions from SNCR. For kilns already controlled with SNCR, we applied no additional emission reductions.

Cement Manufacturing – Wet Process

There are seven sources in this category. The CoST control technology was mid-kiln firing with a 30% reduction in NO_x emissions. We determined that two of these kilns were installing a pilot SCR system as part of a consent decree. One kiln recently went through NSR review and has state-of-the-art control. Another kiln is required to install SNCR as part of a consent decree. No additional reductions were applied for these kilns. For the remaining kilns, we applied low-NO_x burners and SNCR as described in the previous sections.

Coal Cleaning – Thermal Dryer

There was one source in this category. The CoST control technology was a low-NO_x burner with a 50% reduction in NO_x emissions. We could not find any information on this source and accepted the CoST controls.

Comm/Inst Incinerators

There are two sources in this category. The CoST control technology was SNCR with a 45% reduction in NOx emissions. Both of these sources are already controlled by SNCR and we applied no additional emission reductions.

External Combustion Boilers, Elec Gen, Solid Waste

There are six sources in this category. The CoST control technology was SNCR with a 50% reduction in NOx emissions. All six of these sources are already controlled by SNCR and we applied no additional emission reductions.

Fluid Catalytic Cracking Units

There are six sources in this category. The CoST control technology was low-NOx burners and flue gas recirculation with a 55% reduction in NOx emissions. Nearly all sources are already controlled or required to install controls as a result of the EPA's global refinery consent decrees. There is one small refinery in West Texas that does not appear to be covered by a consent decree, so the CoST recommendation was accepted.

Glass Manufacturing – Container, Flat, Pressed

There are 65 sources in this category. The CoST control technology was oxy-firing with an 85% reduction in NOx emissions. There were several concerns about using oxy-firing for this analysis. First, there is a concern about the timing of installing oxy-firing technology. Oxy-firing is typically installed at the time of a furnace rebuild, which is typically done every 10 to 15 years. Second, oxy-firing is not generally required under recent EPA consent decrees. More common control is oxygen-enriched air staging (OEAS). We recommended that OEAS with a 50% NOx reduction instead of OXY-firing at 85% NOx reduction, except for sources that already had NOx controls in place due to a consent decree, NSR requirement, or state regulation. We assumed that a furnace with a NOx emission limit of less than 4 lbs/ton of glass pulled was already reasonably controlled.

ICI Boilers – Coal/Cyclone

There are eight sources in this category. The CoST control technology was SCR with an 80% reduction in NOx emissions. We reviewed the *Evaluation of Control Options for Industrial, Commercial and Institutional (ICI) Boilers Technical Support Document (TSD)*, March, 2011 prepared by the Lake Michigan Air Directors Consortium (LADCO) and the Ozone Transport Commission (OTC). LADCO/OTC also recommended SCR for coal-cyclone boilers. Since the LADCO/OTC recommendation was consistent with the CoST control, we agreed with the CoST control technology for five sources which we determined were uncontrolled. Two sources were determined to be already controlled. One source appears to have shut down their coal-fired boilers. No reductions were applied for these three sources since they are already controlled.

ICI Boilers – Coal/Stoker

There are 45 sources in this category. The CoST control technology was SCR with an 80% reduction in NOx emissions. The LADCO/OTC recommendation was for combustion tuning and SNCR. We agreed with the LADCO/OTC recommendation and assumed a 50% control efficiency. We determined that most of these sources are currently uncontrolled. Two coal-fired boilers are scheduled to be replaced with gas-fired boilers. Two other boilers recently installed SNCR.

ICI Boilers – Coal/Wall

There are 54 sources in this category. The CoST control technology was low-NOx burners and SCR with a 91% reduction in NOx emissions. The LADCO/OTC recommendation was also for low-NOx burners and SCR. Since the LADCO/OTC recommendation was consistent with the CoST control, we agreed with the CoST control technology and emission reductions.

ICI Boilers – Gas, Natural Gas, Process Gas

There are 130 sources in this category. The CoST control technology was SCR with an 80% reduction in NOx emissions. The LADCO/OTC recommendation was for low-NOx burners, flue gas recirculation, or low-NOx burners combined with flue gas recirculation. We agreed with the LADCO/OTC recommendation of low-NOx burners combined with flue gas recirculation and assumed a 60% control efficiency.

Several of these sources are located in the OTR or ozone nonattainment areas, and as a result already have a RACT control requirement or emission limitation that is consistent with the LADCO/OTC recommendations. A few of these sources are located at petroleum refineries and were assumed to be already controlled due to EPA's refinery enforcement initiative.

Municipal Waste Combustors

There are 55 sources in this category. The CoST control technology was SNCR with a 45% reduction in NOx emissions. We determined that 35 of these sources are already controlled with SNCR and no additional reductions were applied. For the remaining uncontrolled sources, we agreed with the CoST controls and emission reductions.

Nitric Acid Manufacturing

There are seven sources in this category. The CoST control technology was non-selective catalytic reduction (NSCR) with a 98% reduction in NOx emissions. All but one of these sources is already controlled by NSCR or SCR.

Petroleum Refinery Process Heaters

There are 28 sources in this category. The CoST control technology was SCR with a 95% reduction in NOx emissions. All of the sources in this category are covered sources under EPA's global refinery enforcement initiative. The settlements generally require 40-60% reductions across all boilers/heaters that

each company operates. Companies have submitted NOx compliance plans to OECA that identify the specific sources that have been controlled or are planned to be controlled, along with the technology used. But it is not possible at present to identify the individual boilers/heaters that actually have been controlled or are scheduled to be controlled due to confidentiality agreements between EPA and companies. No additional reductions were included for this category.

Taconite Ore Processing – Induration – Coal or Gas

There are 10 sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. All of the sources in this category are already subject to Best Available Retrofit Technology (BART) requirements under the Regional Haze program. EPA Region V determined that BART is low-NOx burners and agreed that SCR controls are infeasible for indurating furnaces. No additional reductions were included for this category.

Utility Boilers – Coal/Wall, Oil, Gas

There are 11 sources in this category. The CoST control technology was SCR with a 80 to 90% reduction in NOx emissions depending on fuel type. All of the sources in this category appear to be uncontrolled and we agreed with the CoST control and emission reduction estimate.

REVIEW OF CoST RESULTS FOR THE 25 TO 100 TPY GROUP

Due to the large number of sources in this group, we were not able to review individual permits to determine whether the individual source was already controlled. Instead, our recommendations were based on of state regulations, enforcement actions, engineering judgment, and other available information. We generally assumed that sources located in areas with stringent NOx rules are already well controlled and we assumed that no additional reductions were likely from these sources. This assumption was generally applied in New Jersey, New York and sources located in the Houston nonattainment area. Given more time, we would like to have also applied this assumption in other areas with stringent existing regulations, such as Chicago, Milwaukee, and Baton Rouge. In any future analysis, it would be useful to examine the stringency of rules that apply strictly to nonattainment areas.

Table 2 summarizes the source categories included in our analysis, the CoST recommendation for NOx control, and the recommendation for changing the CoST control measure assignment and associated emission reduction estimates. Following Table 2, there is a discussion for each source group to provide more detail on the rationale for the recommended changes for each source group. Attachments 5 to 8 are tabular comparisons of the initial CoST emission reduction estimates and the recommended changes. All Attachments present the results in terms of tons per ozone season, simply estimated by assuming that

ozone season emissions were equal to 5/12 of the annual emissions. Maps 3A and 3B graphically show the location of sources and the magnitude of the recommended emission reductions.

**Table 2 – CoST Controls and Recommended Changes for
25 to 100 TPY Sources**

Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
Ammonia – NG-fired Reformers	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled.
Cement Kilns	Biosolid Injection Technology	Because of low emissions, assume that the kiln is already controlled or have very low usage which would result in a unreasonably high cost-effectiveness
Cement Manufacturing – Wet	Mid-kiln Firing	Because of low emissions, assume that the kiln is already controlled or have very low usage which would result in a unreasonably high cost-effectiveness
Ceramic Clay Mfg; Drying	Low NOx Burner	Questions about technical feasibility for these category, assume zero reductions
Coal Cleaning – Thermal Dryer	Low NOx Burner	Agree with CoST recommendation
Comm/Inst Incinerators	Selective Non-Catalytic Reduction	Agree with CoST recommendation
External Combustion Boilers, Elec Gen, Sub/Bit Coal	Selective Non-Catalytic Reduction	Agree with CoST recommendation, although questions as to whether the source is already controlled or very low usage which would result in a unreasonably high cost-effectiveness
Fluid Catalytic Cracking Units	Low NOx Burner and Flue Gas Recirculation	Nearly all FCCUs are already controlled due to the OECA global refinery consent decrees.
Gas Turbines	Low NOx Burners	Agreed with CoST recommendation except for those sources where a state regulation already required the source to be controlled.
Glass Manufacturing – Container, Flat, Pressed	OXY-Firing	Because of low emissions, assume that the furnace is already controlled or have very low usage which would result in a unreasonably high cost-effectiveness
ICI Boilers – Coal/Stoker	Selective Catalytic Reduction	Disagreed with CoST recommendation of SCR. CoST has \$2200/ton, which appears very low for ICI boilers. Used LADCO/OTC recommendation of SNCR for Coal-Stokers with a 50% reduction, except for those sources where a state regulation already required the source to be controlled.
ICI Boilers – Coal/Wall	Low NOx Burner and Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a state regulation already required the source to be

Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
		controlled. LADCO/OTC also recommends LNB/SCR
ICI Boilers – Distillate Oil or Process Gas	Selective Catalytic Reduction	Because of low emissions, assume that the boiler is already controlled or have very low usage which would result in a unreasonably high cost-effectiveness
ICI Boilers – Natural Gas	Low NOx Burner and Selective Catalytic Reduction	Disagreed with CoST recommendation of SCR. Used LADCO/OTC recommendation of Low NOx Burners plus Flue Gas Recirculation for Gas-fire ICI boilers with a 60% reduction, except for those sources where a permit or state regulation already required the source to be controlled
ICI Boilers – Residual Oil	Low NOx Burner and Selective Non-Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a state regulation already required the source to be controlled.
Industrial Incinerators	Selective Non-Catalytic Reduction	Agreed with CoST recommendation of SNCR except for those sources where a state regulation already required the source to be controlled.
Iron & Steel Mills – Reheating	Low NOx Burner and Flue Gas Recirculation	Agreed with CoST recommendation except for those sources where a state regulation already required the source to be controlled.
Municipal Waste Combustors	Selective Non-Catalytic Reduction	Agreed with CoST recommendation of SNCR except for those sources where a state regulation already required the source to be controlled.
Nitric Acid Manufacturing	Nonselective Catalytic Reduction	Agreed with CoST recommendation of NSCR except for those sources where a state regulation already required the source to be controlled.
Petroleum Refinery Process Heaters	SCR or Ultra-Low NOx Burner	Nearly all refineries are already controlled due to the OECA global refinery consent decrees, which generally require 40-60% reductions across all boilers/heaters that each company operates. Not possible at present to identify the individual boilers/heaters that actually have been controlled or are scheduled to be control due to confidentiality agreements between EPA and companies.
Utility Boilers – Coal/Wall	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a state regulation already required the source to be controlled
Utility Boilers – Oil/Gas	Selective Catalytic Reduction	Because of low emissions, assume unreasonably high cost-effectiveness for SCR; use LNB/FGR as reasonable control.

Ammonia – NG-fired Reformers

There are seven sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. For all other sources, we agreed with the CoST control and emission reduction estimate.

Cement Kilns

There are six sources in this category. The CoST control technology was either biosolid injection technology with a 23% reduction in NOx emissions or mid-kiln firing with a 30% reduction. Because of the low baseline emissions for these kilns, we assumed that the kilns were already controlled or have low usage which would result in a very high cost-effectiveness. We determined that no reductions be applied for these sources.

Coal Cleaning – Thermal Dryer

There are 10 sources in this category. The CoST control technology was a low-NOx burner with a 50% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate.

Commercial/Institutional Incinerators

There are four sources in this category. The CoST control technology was SNCR with a 45% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate.

External Combustion Boilers, Electric Generation, Coal

There are 14 sources in this category. The CoST control technology was SNCR with a 40% reduction in NOx emissions. It appears that the sources in this category are low usage spreader stokers. Although there may be a concern about the cost-effectiveness for these sources, we agreed with the CoST control and emission reduction estimate.

Fluid Catalytic Cracking Units

There are 21 sources in this category. The CoST control technology was low-NOx burners and flue gas recirculation with a 55% reduction in NOx emissions. All sources in this category are assumed subject to existing control requirements resulting from the OECA global refinery enforcement initiative.

Additionally, eight of the sources are located in the Houston nonattainment area and are likely subject to stringent controls. For these reasons, we assumed no further control or emission reductions for the FCCUs.

Gas Turbines

There are 438 sources in this category. The CoST control technology was for low-NOx burners with a 68% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate, except for those sources located in the OTR and Houston ozone nonattainment area, where we assumed that these sources already had RACT controls.

Glass Manufacturing – Container, Flat, Pressed

There are eight sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. Because of the low baseline emissions for these furnaces, we assumed that the furnaces were already controlled and determined that no reductions be applied for these sources.

ICI Boilers – Coal/Stoker

There are 133 sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. The LADCO/OTC recommendation was for combustion tuning and SNCR. We agreed with the LADCO/OTC recommendation and assumed a 50% control efficiency.

ICI Boilers – Coal/Wall

There are 11 sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. The CoST control technology was low-NOx burners and SCR with a 91% reduction in NOx emissions. The LADCO/OTC recommendation was also for low-NOx burners and SCR. Since the LADCO/OTC recommendation was consistent with the CoST control, we agreed with the CoST control technology and emission reductions.

ICI Boilers – Natural Gas

There are 376 sources in this category. The CoST control technology was low-NOx burners and SCR with a 91% reduction in NOx emissions. The LADCO/OTC recommendation was for low-NOx burners, flue gas recirculation, or low-NOx burners combined with flue gas recirculation. We agreed with the LADCO/OTC recommendation of low-NOx burners combined with flue gas recirculation and assumed a 50% control efficiency, except for those sources located in the OTR and Houston ozone nonattainment area, where we assumed that these sources already had RACT controls.

ICI Boilers – Process Gas

There are 57 sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. Most of these sources are located at petroleum refineries and are assumed subject to existing control requirements resulting from the OECA global refinery enforcement initiative, or are located in the Houston nonattainment area and are likely subject to stringent controls. For these reasons, we assumed no further control or emission reductions.

ICI Boilers – Residual Oil

There are 28 sources in this category. The CoST control technology was low-NOx burner and SNCR with a 69.5% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate, except for those sources located in the OTR and Houston ozone nonattainment area, where we assumed that these sources already had RACT controls.

Industrial Incinerators

There are 21 sources in this category. The CoST control technology was SNCR with a 45% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate, except for those

sources located in the OTR and Houston ozone nonattainment area, where we assumed that these sources already had RACT controls.

Iron & Steel Mills – Reheating

There are 32 sources in this category. The CoST control technology was low-NOx burners and flue gas recirculation with a 77% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate.

Municipal Waste Combustors

There are 25 sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. RTI identified the sources are already controlled and no additional reductions were applied for these sources. For the remaining sources, we agreed with the CoST controls and emission reductions.

Nitric Acid Manufacturing

There are 14 sources in this category. The CoST control technology was NSCR with a 98% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate.

Petroleum Refinery Process Heaters

There are 30 sources in this category. The CoST control technology was SCR with a 90-98% reduction or ultra-low NOx burners with a 30-50% reductions in NOx emissions. Most of these sources are located at petroleum refineries and are assumed subject to existing control requirements resulting from the OECA global refinery enforcement initiative, or are located in the Houston nonattainment area and are likely subject to stringent controls. For these reasons, we assumed no further control or emission reductions.

Utility Boilers – Coal/Wall

There are three sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate.

Utility Boilers – Oil/Gas

There are 27 sources in this category. The CoST control technology was SCR with a 80% reduction in NOx emissions. The LADCO/OTC recommendation was for low-NOx burners or flue gas recirculation. We agreed with the LADCO/OTC recommendation of low-NOx burners combined with flue gas recirculation and assumed a 60% control efficiency.

Attachment 1 – NOx Emission Reductions by State for Sources in the > 100 Ton per Year Reduction Group

<u>State</u>	<u>Number of Sources</u>	NOx emissions reduced from controls in CoST (tons/O3 season) <u>(A)</u>	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) <u>(B)</u>	Size of correction in NOx emission reductions (tons/O3 season) <u>(A - B)</u>
Alabama	24	2,855	2,287	568
Arkansas	6	455	293	162
Delaware	2	206	0	206
Florida	20	2,158	1,370	788
Illinois	21	2,659	1,472	1,187
Indiana	41	5,405	4,510	896
Iowa	10	1,226	999	227
Kansas	7	735	452	283
Kentucky	11	915	838	77
Louisiana	57	7,623	3,622	4,000
Maryland	10	1,933	355	1,578
Michigan	27	2,758	1,768	990
Mississippi	7	1,054	516	538
Missouri	15	1,698	1,562	136
New Jersey	15	417	0	417
New York	30	3,091	281	2,810
Ohio	37	4,098	2,039	2,058
Oklahoma	20	2,949	1,864	1,086
Pennsylvania	52	5,637	2,215	3,422
Tennessee	13	4,741	1,987	2,755
Texas	65	8,860	6,383	2,477
Virginia	28	3,337	3,033	303
West Virginia	9	1,180	793	387
Wisconsin	20	4,092	3,416	676
	547	70,082	42,054	28,028

Attachment 2 – NOx Emission Reductions by Source Group for Sources in the > 100 Ton per Year Reduction Group

Source Group	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Ammonia - NG-Fired Reformers	15	2,427	1,551	875
By-Product Coke Mfg; Oven Underfiring	14	1,199	0	1,199
Cement Kilns	36	3,932	6,586	-2,654
Cement Manufacturing - Dry	20	3,672	2,234	1,438
Cement Manufacturing - Wet	7	1,294	1,120	174
Coal Cleaning-Thrml Dryer; Fluidized Bed	1	50	50	0
Comm./Inst. Incinerators	2	137	0	137
External Combustion Boilers, Solid Waste	6	472	0	472
Fluid Cat Cracking Units; Cracking Unit	6	607	52	556
Fuel Fired Equip; Process Htrs; Pro Gas	2	143	143	0
Glass Manufacturing - Container	34	2,759	678	2,081
Glass Manufacturing – Flat	23	10,241	6,024	4,217
Glass Manufacturing - Pressed	8	684	402	282
ICI Boilers - Coal/Cyclone	8	2,987	1,840	1,147
ICI Boilers - Coal/FBC	3	233	180	53
ICI Boilers - Coal/Stoker	45	4,688	2,938	1,750
ICI Boilers - Coal/Wall	54	12,041	7,996	4,045
ICI Boilers – Gas	10	1,266	910	356
ICI Boilers - Natural Gas	84	7,578	3,452	4,126
ICI Boilers - Process Gas	36	3,868	1,229	2,639
ICI Boilers - Residual Oil	2	199	82	117
Indust. Incinerators	9	586	124	461
In-Proc;Process Gas;Coke Oven/Blast Furn	3	299	0	299

<u>Source Group</u>	<u>Number of Sources</u>	NOx emissions reduced from controls in CoST (tons/O3 season) <u>(A)</u>	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) <u>(B)</u>	Size of correction in NOx emission reductions (tons/O3 season) <u>(A - B)</u>
In-Process; Bituminous Coal; Cement Kiln	2	290	295	-5
Iron & Steel - In-Process Coal Combustion	4	419	0	419
Iron & Steel Mills – Reheating	2	156	156	0
Municipal Waste Combustors	55	1,591	876	715
Nitric Acid Manufacturing	7	687	82	605
Petroleum Refinery Gas-Fired Process Heaters	28	2,025	0	2,025
Taconite Iron Ore - Induration - Coal or Gas	10	829	451	379
Utility Boiler - Coal/Wall	5	555	555	0
Utility Boiler - Oil-Gas/Tangential	2	526	526	0
Utility Boiler - Oil-Gas/Wall	4	1,645	1,524	121
	547	70,082	42,054	28,028

Attachment 3 – NOx Emission Reductions by 3-Digit NAICS Code for Sources in the > 100 Ton per Year Reduction Group

3-Digit NAICS Code	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
211 Oil and Gas Extraction	1	46	30	16
212 Mining (except Oil and Gas)	11	879	500	379
221 Utilities	10	1,186	853	333
311 Food Mfg	12	1,181	815	366
312 Beverage and Tobacco Product Mfg	7	761	761	0
322 Paper Mfg	70	11,616	7,968	3,648
324 Petroleum and Coal Products Mfg	49	3,942	239	3,703
325 Chemical Mfg	132	19,689	10,753	8,937
3272 Glass and Glass Product Mfg	64	13,588	7,047	6,540
3273 Cement and Concrete Product Mfg	64	9,113	10,183	-1,070
3274 Lime & Gypsum Product Mfg	1	75	52	22
331 Primary Metal Mfg	50	4,908	1,837	3,070
333 Machinery Mfg	1	57	35	21
336 Transportation Equipment Mfg	2	148	103	46
424 Merchant Wholesalers, Nondurable Goods	2	160	0	160
531 Real Estate	1	72	0	72
562 Waste Mgmt and Remediation Services	65	2,366	843	1,523
611 Educational Services	5	295	34	261
	547	70,082	42,054	28,028

Attachment 4 – NOx Emission Reductions by 3-Digit NAICS Code for Sources in the > 100 Ton per Year Reduction Group

Recommended Change to CoST Control	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Already Controlled	138	12,973	0	12,973
Already Controlled by Glass CD	12	1,034	0	1,034
Already Controlled By Refinery CD	52	4,300	0	4,300
Control Technically or Economically Infeasible	18	1,618	0	1,618
Fuel Switch Already Occurred	4	2,370	0	2,370
Low NOx Burner	7	629	500	129
Low NOx Burner and Flue Gas Recirculation	88	8,792	6,022	2,769
Low NOx Burner and SCR	44	7,996	7,996	0
Low NOx Burner and SNCR	41	5,895	10,236	-4,341
Non-Selective Catalytic Reduction	1	82	82	0
Oxygen Enriched Air Staging	47	12,077	7,104	4,973
Selective Catalytic Reduction (SCR)	27	6,088	6,088	0
Selective Non-Catalytic Reduction (SNCR)	62	5,109	4,026	1,083
Source Already Shutdown	6	1,120	0	1,120
	547	70,082	42,054	28,028

Attachment 5 – NOx Emission Reductions by State for Sources in the 25 to 100 Ton per Year Reduction Group

<u>State</u>	<u>Number of Sources</u>	NOx emissions reduced from controls in CoST (tons/O3 season) <u>(A)</u>	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) <u>(B)</u>	Size of correction in NOx emission reductions (tons/O3 season) <u>(A - B)</u>
Alabama	38	641	517	123
Arkansas	14	277	203	74
Delaware	5	73	58	15
Florida	27	532	399	133
Illinois	91	1,519	845	675
Indiana	44	894	580	314
Iowa	19	422	309	113
Kansas	31	562	421	140
Kentucky	33	619	407	212
Louisiana	101	2,046	1,467	579
Maryland	18	353	209	144
Michigan	67	1,149	844	304
Mississippi	22	366	343	23
Missouri	13	224	179	45
New Jersey	7	72	11	61
New York	41	685	59	625
Ohio	86	1,476	1,075	402
Oklahoma	40	749	669	81
Pennsylvania	79	1,359	423	936
Tennessee	42	742	514	228
Texas	374	6,444	3,311	3,133
Virginia	30	450	350	100
West Virginia	21	421	334	87
Wisconsin	37	697	471	226
	1280	22,774	14,000	8,774

Attachment 6 – NOx Emission Reductions by Source Group for Sources in the 25 to 100 Ton per Year Reduction Group

Source Group	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Ammonia - NG-Fired Reformers2	7	200	155	45
Cement Kilns	4	93	0	93
Cement Manufacturing - Wet	2	60	0	60
Ceramic Clay Mfg; Drying	4	29	0	29
Coal Cleaning-Thrml Dryer; Fluidized Bed	10	188	188	0
Comm./Inst. Incinerators	4	47	47	0
Ext Comb Boilers, Elec Gen, Nat Gas (2)	1	28	28	0
Ext Comb Boilers, Elec Gen, Sub/Bit Coal (3)	14	158	158	0
Fbrglass Mfg; Txtle-Type Fbr; Recup Furn	2	9	9	0
Fluid Cat Cracking Units; Cracking Unit	21	393	0	393
Fuel Fired Equip; Furnaces; Natural Gas	3	18	18	0
Fuel Fired Equip; Process Htrs; Pro Gas	7	86	86	0
Gas Turbines - Natural Gas	438	7,193	5,749	1,444
Glass Manufacturing - Flat	8	190	0	190
ICI Boilers - Coal/FBC	1	35	22	13
ICI Boilers - Coal/Stoker	133	2,502	1,629	873
ICI Boilers - Coal/Wall	11	246	246	0
ICI Boilers - Distillate Oil	4	75	0	75
ICI Boilers - Gas	26	601	0	601
ICI Boilers - Natural Gas	350	6,814	3,705	3,109
ICI Boilers - Oil	2	41	0	41
ICI Boilers - Process Gas	31	609	0	609
ICI Boilers - Residual Oil	28	484	437	47

<u>Source Group</u>	<u>Number of Sources</u>	<u>NOx emissions reduced from controls in CoST (tons/O3 season) (A)</u>	<u>Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)</u>	<u>Size of correction in NOx emission reductions (tons/O3 season) (A - B)</u>
Indust. Incinerators	21	230	118	113
In-Proc;Process Gas;Coke Oven/Blast Furn	4	33	8	25
Iron & Steel - In-Process Comb - Coal	1	19	0	19
Iron & Steel Mills - Reheating	32	481	481	0
Municipal Waste Combustors	25	472	228	243
Nitric Acid Manufacturing	14	363	289	74
Petroleum Refinery Gas-Fired Process Heaters	30	456	0	456
Solid Waste Disp;Gov;Other Incin;Sludge	1	6	6	0
Space Heaters - Natural Gas	2	17	13	4
Steel Foundries; Heat Treating Furn	7	122	122	0
Surf Coat Oper;Coating Oven Htr;Nat Gas	2	11	0	11
Utility Boiler - Coal/Wall	2	48	48	0
Utility Boiler - Coal/Wall2	1	13	13	0
Utility Boiler - Oil-Gas/Tangential	8	99	62	37
Utility Boiler - Oil-Gas/Wall	19	307	137	170
	1280	22,774	14,000	8,774

Attachment 7 – NOx Emission Reductions by 3-Digit NAICS Code for Sources in the 25 to 100 Ton per Year Reduction Group

3-Digit NAICS Code	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
211 Oil and Gas Extraction	146	2,674	2,573	100
212 Mining (except Oil and Gas)	12	247	227	20
213 Support Activities for Mining	1	20	20	0
221 Utilities	96	1,575	1,035	540
311 Food Manufacturing	46	715	450	266
312 Beverage and Tobacco Products	9	151	91	60
313 Textile Mills	1	24	15	9
314 Textile Product Mills	1	12	7	4
316 Leather and Allied Product Manufacturing	1	10	7	3
321 Wood Product Manufacturing	6	100	56	44
322 Paper Manufacturing	79	1,662	1,028	634
324 Petroleum and Coal Products	115	2,083	527	1,556
325 Chemical Manufacturing	332	6,480	3,218	3,262
326 Plastics and Rubber Products	13	206	142	65
327 Nonmetallic Mineral Product Manufacturing	24	417	32	385
331 Primary Metal Manufacturing	87	1,380	1,094	285
332 Fabricated Metal Product Manufacturing	4	80	46	33
333 Machinery Manufacturing	2	20	14	6
334 Computer and Electronic Products	1	9	9	0
336 Transportation Equipment Manufacturing	13	261	192	69
337 Furniture and Related Products	2	18	18	0
447 Gasoline Stations	1	7	0	7
454 Nonstore Retailers	1	9	0	9

<u>3-Digit NAICS Code</u>	<u>Number of Sources</u>	NOx emissions reduced from controls in CoST (tons/O3 season) <u>(A)</u>	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) <u>(B)</u>	Size of correction in NOx emission reductions (tons/O3 season) <u>(A - B)</u>
482 Rail Transportation	3	37	23	14
486 Pipeline Transportation	156	2,551	2,034	517
488 Support Activities for Transportation	1	18	12	6
531 Real Estate	8	147	0	147
541 Professional Services	6	81	77	4
561 Administrative and Support Services	1	8	0	8
562 Waste Mgmt and Remediation Services	21	376	184	192
611 Educational Services	62	963	617	346
622 Hospitals	7	116	36	80
713 Amusement, Gambling, and Recreation	2	49	45	4
721 Accommodation	2	25	10	15
922 Justice, Public Order, and Safety Activities	4	29	17	12
923 Administration of Human Resources	1	12	8	4
928 National Security and International Affairs	13	201	135	66
	1280	22,774	14,000	8,774

Attachment 8 – NOx Emission Reductions by 3-Digit NAICS Code for Sources in the 25 to 100 Ton per Year Reduction Group

Recommended Change to CoST Control	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) <u>(A)</u>	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) <u>(B)</u>	Size of correction in NOx emission reductions (tons/O3 season) <u>(A - B)</u>
Already Controlled	207	3,380	0	3,380
Already Controlled by Refinery CD	40	704	0	704
Low NOx Burner	362	6,087	6,087	0
Low NOx Burner and Flue Gas Recirculation	361	6,726	4,491	2,235
Low NOx Burner and SCR	11	246	246	0
Low NOx Burner and SNCR	24	437	437	0
Natural Gas Reburn	1	28	28	0
Non-Selective Catalytic Reduction	12	289	289	0
Questions About Feasibility	1	22	0	22
Questions About Feasibility - Cement	6	154	0	154
Questions About Feasibility - Ceramic Clay Mfg	4	29	0	29
Questions about Feasibility - Coating Ovens	2	11	0	11
Questions about Feasibility - Distillate Oil	6	116	0	116
Questions About Feasibility - Glass	7	167	0	167
Questions about Feasibility - Process Gas	50	1,070	0	1,070
Selective Catalytic Reduction	8	216	216	0
Selective Non-Catalytic Reduction	178	3,094	2,207	886
	1280	22,774	14,000	8,774

To: US EPA OAQPS
From: SRA International, Inc.
Subject: Summary of State NO_x Regulations for Selected Stationary Sources
Date: September 30, 2014

SRA compiled a summary of state/local NO_x emission control regulations pertaining six categories of nonEGUs:

- Cement kilns
- Industrial/Commercial/Institutional (ICI) Boilers – Coal-fired
- ICI Boilers – Gas-fired
- ICI Boilers – Oil-fired
- Gas Turbines
- Internal Combustion (IC) Engines

The analysis included 27 states in the eastern two-thirds of the U.S. For each of these states and source categories, we identified state-specific sub-categories (e.g. fuel type or size threshold), the NO_x emission limit or control requirement, averaging time for the emission limit, geographic applicability within the state, testing/monitoring requirements, and rule citation. This information is contained in the attached spreadsheet (Draft State NO_x RACT Limits 2014_04_01.xlsx).

Attachment 1 is an overall summary of the relative stringency of the NO_x requirements by geographic area and source category. We also prepared a 2-page summary for each of the six categories to concisely compare state NO_x emission limits or control requirements. These are shown in Attachments 2 to 7, along with notes highlighting the major differences between the state regulations.

Please let us know should you have questions or comments about any of the data presented in this memorandum.

Attachment 1 – Relative Stringency of NOx Requirements

Source Category	States/Areas with Most Stringent Regulations	States/Areas with Less Stringent Regulations	States with No Regulations or Sources
Cement Kilns ¹	<i>States:</i> IL, MD, NY, PA, TX <i>Areas:</i> Ellis County, TX	<i>States:</i> AL (NOx SIP area), IN, KY, MO, MI, OH, SC, TN, VA, WV	<i>States:</i> AR, FL, GA, MS, OK <i>States with no cement kilns:</i> CT, DE, LA, MA, NC, NJ, WI
Coal-fired ICI Boilers ²	<i>States:</i> NY <i>Areas:</i> Chicago, St. Louis (IL portion), Baton Rouge, Houston-Galveston (coke-fired), Milwaukee,	<i>States:</i> FL, GA, IN, MA, MD, MI, PA, TN, VA <i>Areas:</i> Chicago, St. Louis (MO portion), Baton Rouge, Charlotte, Cleveland	<i>States:</i> AL, AR, KY, MS, OK, SC, TX (except Houston-Galveston) WV <i>NE States with no coal-fired ICI boilers:</i> CT, DE, NJ
Gas-fired ICI Boilers	<i>States:</i> NJ, NY, PA <i>Areas:</i> Chicago, St. Louis (IL portion), Baton Rouge, Beaumont-Port Arthur, Cleveland, Dallas, Houston, Milwaukee	<i>States:</i> CT, DE, FL, GA, MA, MD, MI, MO, TN, VA <i>Areas:</i> Clark/Floyd Counties, St. Louis (MO portion), Charlotte	<i>States:</i> AL, AR, KY, MS, OK, SC, WV
Oil-fired ICI Boilers	<i>States:</i> NJ, NY, PA <i>Areas:</i> Chicago, St. Louis (IL portion), Baton Rouge, Cleveland, Dallas, Houston, Milwaukee	<i>States:</i> CT, DE, FL, GA, MA, MD, MI, TN, VA <i>Areas:</i> Clark/Floyd Counties, St. Louis (MO portion), Charlotte	<i>States:</i> AL, AR, KY, MS, OK, SC, WV
Gas Turbines	<i>States:</i> NJ <i>Areas:</i> GA 45-county area, Dallas, Houston, Milwaukee	<i>States:</i> CT, DE, FL, LA, MA, MD, NY, PA, TN, VA <i>Areas:</i> Chicago, St. Louis (IL portion), St. Louis (MO portion), Charlotte, Cleveland,	<i>States:</i> AL, AR, IN, KY, MI, MS, OK, SC, WV
IC Engines > about 500 hp	<i>States:</i> MD, NJ, NY <i>Areas:</i> Chicago, St. Louis (IL portion), Dallas, Houston	<i>States:</i> CT, DE, MA, MI, PA, TN, VA <i>Areas:</i> Baton Rouge, St. Louis (MO portion), Charlotte, Cleveland, Milwaukee	<i>States:</i> AL, AR, IN, KY, MS, OK, SC, WV

- 1) Cement kiln emission limits imposed by recent EPA enforcement settlements tend to be more stringent than the emission control requirements in state rules.
- 2) CT, DE and NJ have no active coal-fired boilers, so the stringency of their regulations for coal-fired ICI boilers is difficult to evaluate

Attachment 2 - Cement Kilns

State	NOx Limit (lbs/ton clinker)			
	Long Dry	Long Wet	Pre-heater	Pre-calciner
AL	Ozone season: low-NOx burners, mid-kiln system firing, or approved ACT			
AR	No Limits	No Limits	No Limits	No Limits
CT	No Cement Kilns in State			
DE	No Cement Kilns in State			
FL	No Limits	No Limits	No Limits	No Limits
GA	No Limits	No Limits	No Limits	No Limits
IL	5.1	5.1	3.8	2.8
IN	6.0	5.1	3.8	2.8
IN (Clark/Floyd)	10.8 (op day)/ 6 (30 day)	No Limits	5.9 (op day)/ 4.4 (30 day)	No Limits
KY	6.6	6.6	6.6	6.6
LA	No Cement Kilns in State			
MA	No Cement Kilns in State			
MD	5.1	6.0	2.8	2.8
MI	6.0	5.1	3.8	2.8
MO	6.0	6.8	4.1	2.7
MS	No Limits	No Limits	No Limits	No Limits
NC	No Cement Kilns in State			
NJ	No Cement Kilns in State			
NY	Case-by-case RACT Determination			
OH	Ozone season: low-NOx burners, mid-kiln system firing, or approved ACT			
OK	No Limits	No Limits	No Limits	No Limits
PA	3.44*	3.88*	2.36*	2.36*
SC	Ozone season: low-NOx burners, mid-kiln system firing, or approved ACT			
TN	Ozone season: low-NOx burners, mid-kiln system firing, or approved ACT			
TX	5.1	4	3.8	2.8
TX (Ellis County)	No Limits	3.4	No Limits	1.7
VA	Case-by-case RACT Determination			
WI	No Cement Kilns in State			
WV	Ozone season: low-NOx burners, mid-kiln system firing, or approved ACT			

ACT = Alternative Control Technology

* Pennsylvania has proposed "RACT 2" presumptive RACT limits

Observations Regarding State NO_x Rules for Cement Kilns:

❖ Geographic Applicability

- All NO_x SIP Call states with cement kilns have NO_x rules in place
- Since only portions of Alabama, Michigan, and Missouri were affected by NO_x SIP Call, the NO_x rules only apply in the affected counties.
- States not included in the NO_x SIP Call do not have NO_x RACT for cement kilns, except for Texas. The Texas NO_x requirements only apply in Bexar, Comal, Ellis, Hays, and McLennan Counties.

❖ Form of NO_x Limitation or Control Requirement

- A few states express the requirement as “at least one of the following: low-NO_x burners, mid-kiln system firing, alternative control techniques or reasonably available control technology approved by the Director and the EPA as achieving at least the same emissions decreases as with low-NO_x burners or mid-kiln system firing.”
- A few states specify presumptive emission limits in terms of pounds of NO_x per ton of clinker.
- Three states do not set presumptive emission limits but rather require facilities to submit a case-by-case RACT determination. Pennsylvania has a proposed regulation that will specify presumptive RACT limits; current rules require sources to hold 1 trading allowance per ton of NO_x calculated by multiplying tons clinker by the presumptive NO_x limit.

❖ Stringency of NO_x Limitation or Control Requirement

- For states requiring “low-NO_x burners, mid-kiln system firing, or ACT”, it is generally assumed that this will result in a 30% reduction from uncontrolled levels.
- For states with numerical emission limits, the limits generally represent a 20 – 40 % reduction from uncontrolled levels, depending on the type of kiln.
- Texas has very stringent limits for kilns in Ellis County.
- Pennsylvania has proposed presumptive RACT emission limitations in April 2014 that are more stringent than existing presumptive RACT limits in other states.

Attachment 3 – Coal-fired Boilers

State	Geographic Area	NOx Limit (lbs/mmBtu)		
		Boilers 50-100 mmBtu/hr	Boilers 100 - 250 mmBtu/hr	Boilers >250 mmBtu/hr
AL	Statewide	No limits	No limits	No limits
AR	Statewide	No limits	No limits	No limits
CT	Statewide	0.29 to 0.43	0.29 to 0.43	0.29 to 0.43
DE	Statewide	LEA, Low NOx, FGR	0.38 to 0.43	0.38 to 0.43
FL	Broward, Dade, Palm Beach Counties	0.9	0.9	0.9
GA	45 county area	No limits	30 ppmvd @ 3% O ₂	0.7
IL	Chicago & St Louis areas	Tune-up	0.12 CFB 0.25 Other	0.12 CFB 0.18 Other
IN	Clark and Floyd Counties	No limits	0.4 to 0.5	0.4 to 0.5
KY	Statewide	No limits	No limits	No limits
LA	Baton Rouge 5 counties & Region of Influence	0.2	0.1	0.1
MA	Statewide	0.43	0.33 to 0.45	0.33 to 0.45
MD	Select counties	No limits	0.38 to 1.0	0.38 to 1.0
MI	Fine grid zone	No limits	No limits	0.4
MO	St Louis area	No limits	0.45 to 0.86	0.45 to 0.86
MS	Statewide	No limits	No limits	No limits
NC	Charlotte 6 county area	No limits	0.4 to 0.5	1.8
NJ	Statewide	0.43 to 1.0	0.38 to 1.0	0.38 to 1.0
NY	Statewide	No limits	0.08 to 0.20	0.08 to 0.20
OH	Cleveland 8 county area	0.3	0.3	0.3
OK	Statewide	No limits	No limits	No limits
PA	Statewide	0.45	0.45	0.20 to 0.35
SC	Statewide	No limits	No limits	NOx SIP Call
TN	5 Counties	Source specific RACT	Source specific RACT	Source specific RACT
TX	Houston area	0.057 coke-fired	0.057 coke-fired	0.057 coke-fired
VA	Northern VA	No limits	0.38 to 1.0	0.38 to 1.0
WI	Milwaukee 7 county area	0.10 to 0.25	0.10 to 0.25	0.10 to 0.20
WV	Statewide	No limits	No limits	No limits

Observations Regarding State NO_x Rules for Coal-fired Boilers:

❖ Geographic Applicability

- States in the OTR (CT, DE, MA, MD, NJ, NY, and PA) have NO_x emission requirements that apply statewide, not just in ozone nonattainment areas.
- Six states (AL, AR, KY, MS, OK, and WV) do not have regulations limiting NO_x emissions.
- For the remaining states (FL, GA, IL, IN, KY, LA, MI, MO, NC, OH, TN, VA, WI), the NO_x emission control requirements only apply in ozone nonattainment areas.
- Texas only has emission limitations for coke-fired boilers in the Houston-Galveston nonattainment area.

❖ Size Applicability

- Most of the states do not have NO_x emission requirements for boilers less than 100 mmBtu/hour.
- 10 states do regulation boilers in the 50-100 mmBtu size range.

❖ Form of NO_x Limitation or Control Requirement

- Nearly all states express the NO_x emission limits in terms of lbs/mmBtu.
- A few states require either a case-by-case RACT determination or specify specific types of control equipment (e.g., low-NO_x burners, flue gas recirculation).

❖ Stringency of NO_x Limitation or Control Requirement

- Most states specify different emission limits for different types of boilers and firing types (e.g., dry bottom tangential-fired) vs. dry bottom wall-fired)
- A few states in the Northeast have very few or no coal-fired ICI boilers, so the stringency of the regulations in those states is difficult to evaluate. These states are CT, DE, NJ and MA.
- For boilers greater than 100 mmBtu/hour, the LADCO/OTC¹ Phase I recommended limits are in the 0.2-0.3 lbs/mmBtu range (depending on boiler/firing configuration). The LADCO/OTC Phase II recommended limits are in the 0.1-0.2 lbs/mmBtu range. Four areas have limits that generally meet the LADCO/OTC recommendations (Chicago, Baton Rouge, New York State, and Milwaukee.
- Texas has a very stringent limit (0.057 lbs/mmBtu) for coke-fired boilers in the Houston-Galveston area.

¹ *Evaluation of Control Options for Industrial, Commercial and Institutional (ICI) Boilers Technical Support Document (TSD), March, 2011* prepared by the Lake Michigan Air Directors Consortium (LADCO) and the Ozone Transport Commission (OTC).

Attachment 4 – Gas-fired Boilers

State	Geographic Area	NOx Limit (lbs/mmBtu)		
		Boilers 50-100 mmBtu/hr	Boilers 100 - 250 mmBtu/hr	Boilers >250 mmBtu/hr
AL	Statewide	No Limits	No Limits	No Limits
AR	Statewide	No Limits	No Limits	No Limits
CT	Statewide	0.2 to 0.43	0.2 to 0.43	0.2 to 0.43
DE	Statewide	LEA, low NOx, FGR	0.2	0.2
FL	Broward, Dade, Palm Beach Counties	0.2 to 0.5	0.2 to 0.5	0.2 to 0.5
GA	45 county area	30 ppmvd @ 3% O ₂	30 ppmvd @ 3% O ₂	0.2
IL	Chicago & St. Louis Areas	Tune-up	0.08	0.08
IN	Clark and Floyd Counties	No Limits	0.2	0.2
KY	Statewide	No Limits	No Limits	No Limits
LA	Baton Rouge 5 counties & Region of Influence	0.1 to 0.2	0.1	0.1
MA	Statewide	0.1	0.2	0.2 to 0.28
MD	Select counties	Tune-up	0.2	0.2
MI	Fine grid zone	No limits	Source specific RACT	0.2
MO	St Louis area	No limits	0.2 to 0.5	0.2 to 0.5
MS	Statewide	No limits	No limits	No Limits
NC	Charlotte 6 county area	0.3	0.3	0.3
NJ	Statewide	0.1 to 0.5	0.1	0.1
NY	Statewide	0.05	0.06	0.08
OH	Cleveland 8 county area	0.1	0.1	0.1
OK	Statewide	No limits	No limits	No limits
PA	Statewide	0.08	0.08	0.08
SC	Statewide	No limits	No limits	No Limits
TN	5 Counties	Source specific RACT	Source specific RACT	Source specific RACT
TX	Dallas and Houston areas	0.03 or 90% reduction	0.03 or 90% reduction	0.03 or 90% reduction
TX	Beaumont area	0.10	0.10	0.10
VA	Northern VA	0.2	0.2	0.2
WI	Milwaukee 7 county area	No limits	0.08	0.08
WV	Statewide	No limits	No limits	No Limits

Observations Regarding State NO_x Rules for Gas-fired Boilers:

❖ Geographic Applicability

- States in the OTR (CT, DE, MA, MD, NJ, NY, and PA) have NO_x emission requirements that apply statewide, not just in ozone nonattainment areas.
- Six states (AL, AR, KY, MS, OK, and WV) do not have regulations limiting NO_x emissions.
- For the remaining states (FL, GA, IL, IN, KY, LA, MI, MO, NC, OH, TN, TX, VA, WI), the NO_x emission control requirements only apply in ozone nonattainment areas.

❖ Size Applicability

- About half of the states have NO_x emission requirements for boilers less than 100 mmBtu/hour, ranging from combustion tuning to emission limits as low as 0.05 lbs/mmBtu.

❖ Form of NO_x Limitation or Control Requirement

- Nearly all states express the NO_x emission limits in terms of lbs/mmBtu.
- A few states require either a case-by-case RACT determination or specify specific types of control equipment (e.g., low-NO_x burners, flue gas recirculation).

❖ Stringency of NO_x Limitation or Control Requirement

- The LADCO/OTC Phase I recommendations are combustion tuning for boilers less than 100 mmBtu/hour, and either 0.1 lbs/mmBtu or 50% reduction for boilers greater than 100 mmBtu/hr.
- The LADCO/OTC Phase II recommendations are either 0.05-0.1 lbs/mmBtu or 60% reduction.
- New Jersey and New York have state-wide limits that are consistent with the OTC/LADCO Phase II recommendations. Pennsylvania has proposed state-wide limits that are consistent with the OTC/LADCO Phase II recommendations.
- Five areas (Chicago, Baton Rouge, Beaumont-Port Arthur, Cleveland, and Milwaukee) have limits that are consistent with the OTC/LADCO Phase II recommendations.
- Dallas and Houston have the most stringent emission limitations – 0.02 lbs/mmBtu for greater than 100 mmBtu/hr units.

Attachment 5 – Oil-fired Boilers

State	Geographic Area	NOx Limit (lbs/mmBtu)		
		Boilers 50-100 mmBtu/hr	Boilers 100 - 250 mmBtu/hr	Boilers >250 mmBtu/hr
AL	Statewide	No limits	No limits	No limits
AR	Statewide	No limits	No limits	No limits
CT	Statewide	0.2 Distillate 0.25-0.43 Resid.	0.2 Distillate 0.25-0.43 Resid.	0.2 Distillate 0.25-0.43 Resid.
DE	Statewide	LEA, Low NOx, FGR	0.38 to 0.43	0.38 to 0.43
GA	45 county area	30 ppmvd	30 ppmvd	0.3
IL	Chicago & St Louis areas	Tune-up	0.1 Distillate 0.15 Resid.	0.1 Distillate 0.15 Resid.
IN	Clark and Floyd Counties	No limits	0.2 Distillate 0.3 Resid.	0.2 Distillate 0.3 Resid.
KY	Statewide	No limits	No limits	NOx SIP Call
LA	Baton Rouge	0.2	0.1	0.1
MA	Statewide	Tune-up	0.3 Distillate 0.4 Resid.	0.25 to 0.28
MD	Select counties	No limits	0.25	0.25
MI	Fine grid zone	No limits	No limits	0.3 Distillate 0.4 Residual
MO	St Louis area	No limits	0.3	0.3
MS	Statewide	No limits	No limits	No limits
NC	Charlotte 6 county area	0.2	0.2	0.2
NJ	Statewide	Tune-up	0.1 Distillate 0.2 Resid.	0.1 Distillate 0.2 Resid.
NY	Statewide	0.08 to 0.2	0.15	0.15 to 0.2
OH	Cleveland 8 county area	0.12 Distillate 0.23 Resid.	0.12 Distillate 0.23 Resid.	0.12 Distillate 0.23 Resid.
OK	Statewide	New only	New only	New only
PA	Statewide	0.12 Distillate 0.20 Resid.	0.12 Distillate 0.20 Resid.	0.12 Distillate 0.20 Resid.
SC	Statewide	No limits	No limits	No limits
TN	5 Counties	Case-by-Case RACT	Case-by-Case RACT	Case-by-Case RACT
TX	Dallas and Houston areas	No limits	~0.01	~0.01
VA	Northern VA	0.25 to 0.43	0.25 to 0.43	0.25 to 0.43
WI	Milwaukee 7 county area	No limits	0.10 Distillate 0.15 Resid.	0.10 Distillate 0.15 Resid.
WV	Statewide	No limits	No limits	No limits

Observations Regarding State NO_x Rules for Oil-fired Boilers:

❖ Geographic Applicability

- States in the OTR (CT, DE, MA, MD, NJ, NY, and PA) have NO_x emission requirements that apply statewide, not just in ozone nonattainment areas.
- Six states (AL, AR, MS, OK, SC, and WV) do not have regulations limiting NO_x emissions.
- For the remaining states (FL, GA, IL, IN, KY, LA, MI, MO, NC, OH, TN, TX, VA, WI), the NO_x emission control requirements only apply in ozone nonattainment areas.

❖ Size Applicability

- About half of the states have NO_x emission requirements for boilers less than 100 mmBtu/hour, ranging from combustion tuning to emission limits as low as 0.08 lbs/mmBtu.

❖ Form of NO_x Limitation or Control Requirement

- Nearly all states express the NO_x emission limits in terms of lbs/mmBtu.
- A few states require either a case-by-case RACT determination or specify specific types of control equipment (e.g., low-NO_x burners, flue gas recirculation).

❖ Stringency of NO_x Limitation or Control Requirement

- The LADCO/OTC Phase I recommendations for distillate oil are combustion tuning for boilers less than 100 mmBtu/hour, and either 0.1 lbs/mmBtu or 50% reduction for boilers greater than 100 mmBtu/hr. The LADCO/OTC Phase II recommendations for distillate oil are either 0.08-0.1 lbs/mmBtu or 60% reduction.
- Only New Jersey has state-wide limits that are consistent with the OTC/LADCO Phase II recommendations for distillate oil.
- Three areas (Chicago, Baton Rouge, and Milwaukee) have limits that are consistent with the OTC/LADCO Phase II recommendations for distillate oil.
- The LADCO/OTC Phase I recommendations for residual oil are combustion tuning for boilers less than 100 mmBtu/hour, and either 0.2 lbs/mmBtu or 60% reduction for boilers greater than 100 mmBtu/hr. The LADCO/OTC Phase II recommendations for residual oil are either 0.2 lbs/mmBtu or 50-70% reduction.
- New Jersey and New York have state-wide limits that are consistent with the OTC/LADCO Phase II recommendations for residual oil. Pennsylvania has proposed state-wide limits that are consistent with the OTC/LADCO Phase II recommendations for residual oil.
- Four areas (Chicago, Baton Rouge, Charlotte, and Milwaukee) have limits that are consistent with the OTC/LADCO Phase II recommendations for residual oil.
- Dallas and Houston have the most stringent emission limitations – 0.01 lbs/mmBtu for greater than 100 mmBtu/hr units.

Attachment 6 – Gas Turbines

State	Geographic Area	NOx Limit (ppmvd @15% O2)			
		Simple Cycle >25 MW Gas-fired	Simple Cycle >25 MW Oil-fired	Combined Cycle > 25 MW Gas-fired	Combined Cycle > 25 MW Oil-fired
AL	Fine grid zone	No limits	No limits	No limits	No limits
AR	Statewide	No limits	No limits	No limits	No limits
CT	Statewide	55	258 (0.9 lb/mmBtu)	55	258 (0.9 lb/mmBtu)
DE	Statewide	42	88	42	88
GA	45 county area	6	6	6	6
IL	Chicago & St Louis areas	42	96	42	96
IN	Statewide	No limits	No limits	No limits	No limits
KY	Statewide	No limits	No limits	No limits	No limits
LA	Baton Rouge 5 counties & Region of Influence	54 (0.2 lb/mmBtu)	86 (0.3 lb/mmBtu)	54 (0.2 lb/mmBtu)	86 (0.3 lb/mmBtu)
MA	Statewide	65	100	42	65
MD	Select counties	42	65	42	65
MI	Fine grid zone	No limits	No limits	No limits	No limits
MO	St Louis area	75	100	75	100
MS	Statewide	No limits	No limits	No limits	No limits
NC	Charlotte 6 county area	75	95	75	95
NJ	Statewide	33 (2.2 lb/MWh)	53 (3.0 lb/MWh)	33 (2.2 lb/MWh)	53 (3.0 lb/MWh)
NY	Statewide	50	100	42	65
OH	Cleveland 8 county area	42	96	42	96
OK	Statewide	No limits	No limits	No limits	No limits
PA	Statewide	42	75	42	75
SC	Statewide	No limits	No limits	No limits	No limits
TN	5 Counties	source specific RACT	source specific RACT	source specific RACT	source specific RACT
TX	Dallas and Houston areas	9 (0.032 lb/mmBtu)	9 (0.032 lb/mmBtu)	9 (0.032 lb/mmBtu)	9 (0.032 lb/mmBtu)
VA	Northern VA	42	65/77	42	65/77
WI	Milwaukee 7 county area	25 to 42	65 to 96	9	9
WV	Statewide	No limits	No limits	No limits	No limits

Appendix B

Observations Regarding State NO_x Rules for Gas Turbines:

❖ Geographic Applicability

- States in the OTR (CT, DE, MA, MD, NJ, NY, and PA) have NO_x emission requirements that apply statewide, not just in ozone nonattainment areas.
- Nine states (AL, AR, IN, KY, MI, MS, OK, SC, and WV) do not have regulations limiting NO_x emissions.
- For the remaining states (GA, IL, LA, MO, NC, OH, TN, TX, VA, WI), the NO_x emission control requirements only apply in ozone nonattainment areas.

❖ Other Applicability Criteria

- States use a variety size thresholds. For example, Ohio's rules differentiate between units < 3.5 MW and > 3.5 MW. Wisconsin has requirements for three size ranges: 10-25 MW, 25-50 MW, and >50 MW.
- State limits generally differ by type of fuel – gas or oil. Wisconsin also includes limits for biologically derived fuel.
- Some states have different limits for simple-cycle and combined-cycle units. Other states have a single limit that applies to both types of units.

❖ Form of NO_x Limitation or Control Requirement

- States do not specify specific types of control techniques, but rather set a numerical emission limit.
- Most states express limits in terms of “ppmv at 15% oxygen”. Some states use lbs/mmBtu, and the equivalent limits shown in the table above were calculated using based on Part 75 Eq-F5 and F-factors. New Jersey's limits are in terms of lbs/MHr.

❖ Stringency of NO_x Limitation or Control Requirement

- Three areas have very low limits compared to other states/areas: the 45 county area in Georgia, Dallas and Houston-Galveston

Attachment 7 – IC Engines Greater than ~500 hp

State	Geographic Area	NOx Limit (g/hp-hr)			
		Gas-fired, Lean Burn	Gas-fired, Rich Burn	Diesel	Dual Fuel
AL	Fine grid zone	No limits	No limits	No limits	No limits
AR	Statewide	No limits	No limits	No limits	No limits
CT	Statewide	2.5	2.5	8.0	8.0
DE	Statewide	Technology Stds.	Technology Stds.	Technology Stds.	Technology Stds.
GA	45 county area	?	?	?	?
IL	Chicago & St Louis areas	210 ppmvd @ 15% O2 (2.9 g/hp-hr)	150 ppmvd @ 15% O2 (2.2 g/hp-hr)	660 ppmvd @ 15% O2 (9.1 g/hp-hr)	660 ppmvd @ 15% O2 (9.1 g/hp-hr)
IN	Statewide	No limits	No limits	No limits	No limits
KY	Statewide	No limits	No limits	No limits	No limits
LA	Baton Rouge 5 counties & ROI	4.0	2.0	?	?
MA	Statewide	3.0	1.5	9.0	9.0
MD	Select counties	150 ppmvd @ 15% O2 (1.7 g/hp-hr)	110 ppmvd @ 15% O2 (1.6 g/hp-hr)	175 ppmvd @ 15% O2 (2.0 g/hp-hr)	125 ppmvd @ 15% O2 (1.4 g/hp-hr)
MI	Fine grid zone	3.0	1.5	2.3	1.5
MO	St Louis area	3.0 10.0	2.5 to 9.5	2.5 - 8.5	2.5 - 6.0
MS	Statewide	No limits	No limits	No limits	No limits
NC	Charlotte Area	2.5	2.5	8.0	8.0
NJ	Statewide	2.5	1.5	8.0	8.0
NY	Statewide	1.5	1.5	2.3	2.3
OH	Cleveland	3.0	3.0	3.0	3.0
OK	Statewide	No limits	No limits	No limits	No limits
PA	Statewide	3.0	2.0	8.0	8.0
SC	Statewide	No limits	No limits	No limits	No limits
TN	5 Counties	Source specific RACT	Source specific RACT	Source specific RACT	Source specific RACT
TX	Dallas and Houston area	0.5	0.5	2.8 to 6.9	0.5
VA	Northern VA	Source specific RACT	Source specific RACT	Source specific RACT	Source specific RACT
WI	Milwaukee 7 county area	3.0	3.0	3.0	3.0
WV	Statewide	No limits	No limits	No limits	No limits

Observations Regarding State NO_x Rules for IC Engines:

❖ Geographic Applicability

- States in the OTR (CT, DE, MA, MD, NJ, NY, and PA) have NO_x emission requirements that apply statewide, not just in ozone nonattainment areas.
- Eight states (AL, AR, IN, KY, MS, OK, SC, and WV) do not have regulations limiting NO_x emissions.
- For the remaining states (GA, IL, LA, MI, MO, NC, OH, TN, TX, VA, WI), the NO_x emission control requirements only apply in ozone nonattainment areas.

❖ Other Applicability Criteria

- States use a variety size thresholds. For example, Louisiana's rules have separate limits for IC engines that are 150-300 hp, >300 hp, and >1500 hp. New York uses > 200 hp and > 400 hp. Delaware uses > 450 hp, while North Carolina uses > 650 hp.
- State limits generally differ by type of fuel – gas, oil, dual-fuel or landfill/digester gas.
- A few states have different limits lean-burn and rich-burn engines. Other states have a single limit that applies to both types of units.

❖ Form of NO_x Limitation or Control Requirement

- Most states express limits in terms of “gram per brake horsepower hour”.
- Some states use “ppmvd @ 15% O₂”, and the equivalent limits shown in the table above were calculated using conversion factors from ppmv @ 15% O₂ to g/hp-hr from EPA ACT, July 1993 EPA453-R-93-032.
- Delaware specifies control technology standards rather than numerical emission limits.

❖ Stringency of NO_x Limitation or Control Requirement

- Maryland, New Jersey, New York and the Dallas/Houston areas of Texas have limits that are more stringent than other states/areas.



The INGAA Foundation, Inc.

Availability and Limitations of NO_x Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry

Prepared for:

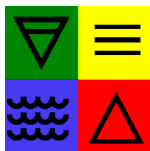
The INGAA Foundation, Inc.

By:

Innovative Environmental Solutions, Inc. &
Optimized Technical Solutions

July 2014

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Innovative
Environmental
Solutions, Inc.



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Executive Summary

New and proposed changes in air emission regulations are likely to impact the interstate natural gas transportation industry. Regulations that are expected to impact the industry include the ozone National Ambient Air Quality Standards (NAAQS) and the nitrogen dioxide (NO₂) one hour NAAQS. Since nitrogen oxides (NO_x) react in the atmosphere to form ozone, it is regulated as a precursor to ozone. As emission control rules are developed and permitting actions implemented in response to these federal standards, there will be ongoing pressure to reduce emissions of NO_x from existing equipment that has not yet been impacted by NO_x control rules, or has been minimally impacted. For example, EPA and states have not yet implemented permitting requirements related to a recent revision to the NO₂ NAAQS. In addition, due to lawsuits and evolving EPA policy, states have been passive in recent years regarding the next set of rules to reduce NO_x to address ozone NAAQS concerns. In response to a new ozone NAAQS planned for 2015, there is a potential for broad NO_x controls in the eastern half of the U.S. to address NO_x transport. Along with the revised ozone NAAQS and implementation of the NO₂ NAAQS, upcoming court decisions, including a Supreme Court decision on EPA authority to institute regional NO_x rules, will likely break the regulatory logjam.

Based on these expected air regulation changes that result in new requirements to reduce NO_x from existing equipment, a significant number of stationary engines that drive natural gas compressors in interstate natural gas transmission service will likely require modification to meet new federal or state NO_x rules or permitting requirements. **Based on current technical resources, the projected time to implement retrofit NO_x control (or replacement) is far in excess of typical regulatory schedules.**

The focus of the research for this report was to evaluate the resources required of the operating companies, emission reduction suppliers, engineering service providers, and contractors to implement NO_x control regulations for low speed reciprocating engines used in the interstate natural gas transportation industry. The information gathered in developing this report included input solicited from both operating companies and vendors who provide emission reduction retrofit equipment. The assessment included an evaluation of an industry database to estimate the number and type of engines that would be impacted by changes to the emission regulations. Resource and schedule requirements assessed in this report are based on the actual fleet (i.e., make, model, NO_x control status) from that database. This study found:

- The special technical expertise to design, construct, and commission emission reduction projects is not widely available to the industry for the slow speed integral engines prevalent in natural gas transmission. Regulations that require installation of NO_x control on a large number of reciprocating engines will require a significant lead time to train and develop employees and service provider resources to implement emission reduction projects on a timely basis.
 - Availability of this special technical expertise and building this capability is the primary resource constraint that will affect the ability to meet regulatory obligations, if those regulations affect a large percentage of the existing fleet. Based on current capabilities and a scenario where NO_x regulations broadly affect the existing fleet of uncontrolled reciprocating engines, the estimated time to complete upgrades to over 2600 engines is

nearly forty years. Although strategies to comply may result in many engines (e.g., lower horsepower, lower use engines) being retired or replaced, scheduling implications due to the lack of available expertise would still extend far beyond the expected regulatory timelines. In addition, even if a smaller percentage of the fleet requires control, the required time (e.g., 15 years for 1000 engines) would likely exceed any expected regulatory schedule. Building this technical expertise to address regulatory implementation timelines are significant concerns.

- Engine NOx control projects are generally much less costly than engine replacement. If the anticipated regulations are implemented, capital costs to modify currently uncontrolled reciprocating engines used in the interstate natural gas transmission industry are estimated at approximately \$4 billion to achieve NOx emission rates of 3 grams per horsepower hour (g/hp-hr) and over \$6 billion to achieve 1 g/hp-hr.
- The age of the impacted equipment (most of the engines are over 40 years old) requires additional time to engineer and construct reliable emission reduction modifications due to inaccurate or missing engineering records that reflect the current equipment configuration.
- Some engines with low specific power output will require extra time to properly design and construct emission reduction modifications and maintain the same power operating range.
- Based on previous experience, the timeline of obtaining air permits is a key parameter defining the overall schedule for completing a specific emission reduction project – i.e., permitting can slow the project timeline.
- Equipment outages that last several weeks to over a month to implement emission reduction modifications may have significant impact on available pipeline capacity and could cause significant capacity disruption, especially if the schedule overlaps with implementation of other regulations such as pipeline integrity testing.

1.0 Introduction

As shown below, air emissions from a natural gas compressor station are regulated by a complex web of federal and state regulation. This report focuses on the potential availability of resources – equipment, people, and expenditures – needed to modify these compressor stations to meet possible NO_x emission requirements.

Air emissions continue to be a major regulatory issue, and air quality regulations pose a risk to normal operations of existing natural gas transmission infrastructure. NO_x emissions are the primary air pollutant of interest from natural gas-fired combustion sources. NO_x can react in the atmosphere to form ozone, so NO_x is regulated as a precursor to ozone. NO_x can also react to form nitrates, and ammonium nitrate is an aerosol that comprises a portion of atmospheric fine particulate (PM_{2.5}). The U.S. Environmental Protection Agency (EPA) establishes NAAQS for six criteria pollutants, including ozone, NO₂, and PM_{2.5}. NO_x emissions are comprised of NO and NO₂, but all NO_x emissions are generally considered NO₂ under the NO₂ NAAQS.

Based on ambient air monitoring, if the air quality in a particular location does not meet (i.e., “attain”) the NAAQS, that geographical area will be designated as a “nonattainment” area. Then, state or local agencies are required to develop regulations that decrease emissions from *existing sources* to reduce ambient pollutant levels and attain the NAAQS. In addition, NO_x emissions may be evaluated by regulatory agencies using a model that simulates the behavior of the exhaust plume (i.e., a “dispersion model”) to assess whether NO₂ impacts beyond the compressor station fence line exceed the NO₂ NAAQS. If so, mitigation would likely be required.

For example, NO_x Reasonably Achievable Control Technology (RACT) regulations may be adopted by a state to address ozone nonattainment within the state. These rules may apply to limited in-state areas (e.g., urban nonattainment areas) or statewide. In addition, many urban and eastern U.S. areas have already reduced NO_x emissions, but NO_x transported from upwind states contributes to nonattainment. This phenomenon is referred to as “NO_x transport,” and EPA may adopt multi-state regional rules to reduce NO_x across the eastern U.S. and mitigate NO_x transport. For natural gas-fired combustion sources, NO_x is the primary pollutant that may be regulated by these rules. Emissions of other pollutants such as formaldehyde, which is regulated as a hazardous air pollutant (HAP), may also trigger emission controls. However, it is generally expected that existing catalyst control providers can meet demands to address new regulatory requirements.

Thus, this report focuses on potential resource constraints associated with regulations that require retrofit installation of NO_x emission control technologies. More specifically, the report focuses on combustion-based technologies – i.e., low emissions combustion (LEC) – for lean burn reciprocating engines commonly used in interstate transmission and most likely subject to retrofit NO_x control in the future (i.e., this older equipment is typically “grandfathered” and many units have not been subject to NO_x regulations to date). The reciprocating engines of interest are low speed “integral” engines uniquely used for gas compression, where the compressor and its driver – i.e., the reciprocating engine used to power the compressor – are integrated into a single piece of equipment with a common crankshaft. These legacy integral engines comprise a large portion of the horsepower capacity in interstate natural gas compression and can also be found in gas processing and, to a lesser extent, in gathering compression. Although these engines have been

in service for many years, because they were designed specifically to compress natural gas, natural gas-fired integral engines remain the most efficient option for gas compression.

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). Rich burn reciprocating engines may require non-selective catalytic reduction (NSCR) to reduce NOx and formaldehyde, but rich burn engines are a smaller percentage of interstate transmission prime movers and many rich burns already use NSCR emissions control in response to the federal HAP standard or state requirements.

The focus of this report is to assess the availability of resources to implement air emission modifications on the reciprocating engines used to transport natural gas on the interstate pipeline system. For example, there are currently a handful (or less) of service providers that provide LEC control for reciprocating engines. Thus, depending upon the breadth and timing of emission control requirements, there is a concern that resource constraints may impact timely compliance or the reliability of gas delivery.

This report will identify potential constraints, including potential bottlenecks in the supply chain, regarding availability of capital equipment and technology service providers to address retrofit NOx control of the existing fleet of equipment. Scheduling issues will be discussed, including constraints that may point to the need for phasing regulatory compliance.

The regulatory context is based on an expectation that existing reciprocating engines that do not include NOx control technology will eventually be required to retrofit NOx control technology in response to recent or upcoming revisions to the federal ozone or NO₂ NAAQS. NOx control resource availability for reciprocating engines is the most probable resource constraint due to the limited service providers and trained labor in this field, so this report focuses on potential resource limitations and the time required to control these engines, especially lean burn engines.

In addition to this Introduction, the report includes:

- An Executive Summary.
- Section 2 discusses the study approach.
- Section 3 provides an overview of reciprocating engine NOx control technologies,
- Section 4 discusses engine demographics (population and type) for interstate transmission prime movers.
- Section 5 presents NOx related air quality regulatory concerns and analysis assumptions and methodology.
- Section 6 presents methodology and results related to costs and schedule.
- Section 7 presents the analysis and discussion of limitation by project phase, and Section 8 provides conclusions.
- Appendices provide a list of acronyms and the survey questions used for discussions with operators, equipment manufacturers, and service providers.

2.0 Study Approach

The information in this report was gathered confidentially by Innovative Environmental Solutions (IES) and Optimized Technical Solutions (OTS) and the information has been consolidated in a manner that the individual responses cannot be broken out by the vendor or operator supplying the information. This is done to prevent business strategies or other competitive information from reaching competitors. All efforts were made to prevent the communication of information that could result in anticompetitive practices.

Interviews were performed with multiple emission reduction vendors and operating companies. In addition, a literature review was performed, and relevant information is cited. There is significant uncertainty regarding the requirements (e.g., required emission levels), geographical breadth, and timing of NO_x regulations. Since there are many possible regulatory outcomes, specific dates and regulations are not a focus, but a general discussion of the NO_x control regulatory threat is provided in Section 5. Instead of considering a specific regulation, the analysis in this report focuses on identifying potential resource constraints based on an assumption that many legacy prime movers without NO_x control will eventually require upgrade (or replacement). To consider technology needs, costs, and scheduling, the analysis considers the engine types (i.e., model) based on an available database. Two NO_x targets are considered (i.e., 3 g/bhp-hr or 1 g/bhp-hr) based on previous experience for likely regulatory endpoints and guidance from advisors, and a general ranking of regulatory risk for three geographical areas is used when assessing implications. States were categorized as high risk/stringency (where regulations may already be in place in some cases – e.g., northeast state where much of the fleet is already controlled), moderate risk (e.g., midwest and eastern states where compressor stations may be implicated as contributors to eastern U.S. NO_x transport), and lower risk states, where regulation is less likely (e.g., northern plains states, where control is less likely unless EPA initiates broad national requirements for existing equipment). In addition, costs were considered under the premise that NO_x control would be widely required for uncontrolled units either due to NO_x regulations (e.g., in response to ozone nonattainment) or permitting actions to address conformance with the NO₂ NAAQS.

This effort began with interviews of multiple interstate gas pipeline operating companies that had previous experience with NO_x reduction projects. In addition, independent interviews were conducted with six different suppliers of equipment and services that modify reciprocating engines used in the interstate natural gas transportation industry. Interviews covered all aspects of the execution of NO_x reduction projects from start to finish. Specific topics in project execution included:

- **Permitting** – Permitting is the process of obtaining air emission permits from the regulating agency – typically a state agency. This phase requires an initial engineering analysis to determine the modifications required and the expected air emissions for each emission source at a facility for the permit application. Defined technologies must be settled upon prior to completing the permit.
- **Initial design** – This portion of the project assesses: (1) which emission reduction technologies are suitable for a facility and the associated suppliers for the emission reduction equipment, (2) the reduction in air emissions that can be expected with the applicable emission reduction equipment, and (3) the initial design for the equipment changes. Input from the suppliers of

emission reduction equipment is usually required during this portion of the project. Initial design information is also necessary to provide information for the permitting process, but other, more detailed design considerations are also addressed under this topic.

- **Cost estimating and scheduling** – This part of the project establishes the expected timeframe and financial costs expected to modify the equipment for emissions control. Personnel resource availability and allocations are also typically performed in this portion of the project execution.
- **Contracting and procurement** – In this portion of the project, detailed cost and schedule information to implement an emission control project is solicited from suppliers and contractors. This requires the creation of design specifications, evaluation criteria, and contractual terms and conditions.
- **Detailed design** – This phase involves developing detailed designs based on specific emission control equipment selected. Detailed design includes but is not limited to the development of material lists, drawings, engine control system modifications, and commission plans.
- **Construction** – This portion of the emission control project is where physical modifications are made to the engine and ancillary equipment.
- **Commissioning** – This is the phase of the emission control project where calibration, configuration, and tuning of the engine is performed to ready the engine for continuous operation. Training of the operating and maintenance personnel is also often performed during this phase.
- **Operation and maintenance** – This is the post-conversion and commissioning portion of the project. Proper operation and maintenance of the engine and emission control equipment is required to ensure compliance with the emission limits.

This report discusses resource constraints for each of these phases for reciprocating engine NOx control projects, as described by the operators and suppliers of emission reduction equipment. For NSCR application to rich burn engines, a higher level review was conducted because it is likely that there are an adequate number of vendors to address market demand and fewer engines are likely to be affected.

Cost and schedule estimates are based on the number and size of engines to be converted, information provided by pipeline operators and suppliers of emission reduction equipment, and reference publications. Factors that influence technology requirements and costs for reciprocating engines include:

- Combustion cycle (two-stroke, four-stroke),
- The engine make and model,
- Brake mean effective pressure (BMEP) of the engine,
- Engine aspiration type (natural, turbocharged), and
- The number of power cylinders.

Based on engines identified in an industry database, this information was used to determine the most probable type of modifications needed to achieve the target NOx emission level.

3.0 Reciprocating Engine NOx Emission Reduction Technology Overview

NOx control technologies for reciprocating engines are discussed below. LEC technologies for lean burn engines are discussed in Section 3.1, and NSCR for rich burn engines is discussed in section 3.2. Section 3.3 discusses SCR. Although SCR has not been applied to existing integral engines, it could be considered by regulatory agencies, especially for lean burn engines where LEC is not available or cannot achieve the target NOx level.

3.1 Reciprocating Internal Combustion Engines – LEC for Lean Burn Engines

An overview of LEC NOx control technologies for lean burn reciprocating engines is described in this section. [1] [2] [3]

NOx emissions from natural gas combustion are formed from nitrogen and oxygen in the combustion air, and NOx emissions increase significantly at higher combustion temperatures. LEC achieves lower NOx by providing sufficient excess air to reduce the maximum combustion temperature and minimize NOx formation. The use of LEC to control NOx is possible on fuel-injected two-stroke cycle engines and many four-stroke cycle engines. Since the excess air may hinder combustion or light-off of the air-fuel charge in the cylinder, LEC-equipped engines generally require a high energy ignition source. This is most commonly implemented by the use of pre-chamber combustion systems that ignite a smaller charge that then ignites the in-cylinder air-fuel mixture. The power operating range may decrease on two-stroke cycle engines when converted to LEC.

Since peak combustion temperatures are influenced by the amount of excess air and air-fuel mixing, there are several methods that can be used to minimize peak temperatures and NOx formation during lean combustion. Regulatory agencies use the term “LEC” broadly and a number of technology approaches can be used depending on the engine and NOx emission limit. In many cases, multiple LEC related technologies may be required – e.g., additional air through new or upgraded turbocharging, higher energy ignition /precombustion chambers, and enhanced mixing. Several primary technologies are described below. For the engine types in the fleet, the analysis considered the proper technology approach to achieve target NOx emissions of 3 g/hp-hr or 1 g/hp-hr.

3.1.1 Enhanced Mixing

Pockets of rich fuel can exist in engines equipped with direct fuel injection. The resulting locally rich fuel mixtures result in localized higher combustion temperatures with an associated increase in NOx formation. Engine modifications to produce enhanced air/fuel mixing can counteract this effect. For example, “high pressure” fuel injection systems have been developed that take advantage of the higher pressure gas available from the pipeline to greatly improve air-fuel mixing. On some engines, enhanced mixing modifications may also require high energy ignition modifications to prevent engine misfires.

3.1.2 Mechanical Modifications

Modifications that can be used to reduce NOx emissions include upgrading or conversion to turbocharging, adding additional turbocharger after-cooling, installing different cam shafts, installing different (e.g., electronic) fuel injection valves, etc. These are not discussed in detail

here as they usually result in minor reductions as an independent action, but are typical technologies that may be included as part of the emissions reduction project. Since dispersion modeling may be required to ensure that modeled offsite impacts do not exceed the NO₂ NAAQS, stack height extensions are a modification that can reduce modeled ground level concentrations. In general, a stack height that is at least 1.5 times the height of the compressor building peak height is desired to avoid building-induced “downwash” that brings the plume to ground level sooner and results in higher modeled impacts.

3.1.3 Operational Control – Ignition Timing

The peak combustion pressure (and thereby the peak combustion temperature) can be lowered by retarding (or delaying) the ignition timing of the engine. The lower combustion temperature results in lower NO_x emissions. Only nominal NO_x reductions are achieved when used in isolation and fuel consumption increases. This may also reduce the maximum power the engine can produce, and typically increases carbon monoxide (CO), volatile organic compounds (VOCs), and total unburned hydrocarbons (THC) emissions. VOCs are regulated as an ozone precursor and are a subset of THC (the methane and ethane components of THC are excluded from VOCs because these two hydrocarbons are minimally reactive in ozone producing atmospheric reactions).

3.1.4 Operational Control – Air/Fuel Ratio

Altering engine control methods can reduce the formation of NO_x and improve the reliability of maintaining emissions at the prescribed level. On engines that utilize air/fuel controls, some NO_x reductions may be possible by changing the control curve to operate the engine leaner without other engine modifications. This control change is limited by the amount of air available from the turbocharger and the ability of the ignition system to ignite the leaner mixture without misfires.

3.1.5 Other (non-LEC) Technologies

The technologies described above are not intended to be a comprehensive list. There are other control methods such as exhaust gas recirculation that are not covered here due to their limited effectiveness and limited use on the types of engines typically utilized in interstate natural gas transmission.

3.2 Rich Burn Reciprocating Internal Combustion Engines – Nonselective Catalytic Reduction

Rich burn engines are designed to operate with minimal excess air – i.e., with combustion air approximately equal to the amount required to completely combust the fuel with minimal excess air. The “stoichiometric” amount of air is the exact amount required to burn the fuel with no excess. For reciprocating engines that operate near stoichiometric conditions (excess oxygen in the exhaust <0.5%), NSCR is the accepted emissions control option. This type of exhaust control technology is commonly used on automobiles and also referred to as a 3-way catalyst because emissions of NO_x, CO, and VOCs can be reduced. For this control technology to work effectively for all three pollutants, an air to fuel ratio controller (AFRC) is required that maintains the AFR over a very narrow operating band. With too little air, NO_x will be low, but CO and VOCs may significantly increase. With too much air (and thus too much oxygen available), CO and VOCs will be reduced (i.e., NSCR operates as an oxidation catalyst), but

NOx reduction across the catalyst will be impacted and post-catalyst NOx will significantly increase.

Catalytic elements used in NSCR can be contaminated by engine oil carryover and other operating factors. Cleaning and replacement is required on a periodic basis. Unburned hydrocarbons in the exhaust stream reduce the life of the catalyst. This is the common technology of choice for rich burn four-stroke cycle engines.

3.3 Selective Catalytic Reduction for Lean Burn Engines

For NOx control from lean burn engines, this report focuses on LEC. SCR is discussed here because it is often considered by regulators when assessing NOx controls for combustion equipment and future control rules may require SCR in some cases (e.g., if LEC is not effective on a particular engine model). SCR is an exhaust control for lean combustion (i.e., excess air is available) that reduces NOx by reaction with ammonia or urea over a catalyst. [4] [5] Ammonia or urea injection is required with precise reagent feedrate control based on the NOx concentration and the NO/NO₂ ratio of the NOx. The reagent and NOx “selectively” react on the catalyst to (ideally) form water and molecular nitrogen (N₂). To date, SCR application to U.S. gas transmission sources has been very limited, and SCR has not been applied to an existing integral engine. Technical concerns about the SCR performance for gas transmission engines include exhaust temperature requirements, reagent control (and sophistication of current systems), and treatment of potential variations in the reciprocating engine exhaust NO/NO₂ ratio.

SCR has been more commonly applied to larger utility scale turbines and boilers, with very limited gas transmission applications to date. Recently, some new 4-stroke cycle lean burn engines have been sited with SCR, but retrofit application to lean burn prime movers has not occurred. While NSCR for rich burn engines exploits the chemical processes available at stoichiometric combustion to reduce multiple pollutants, SCR “selectively” reduces NOx. The use of SCR is most effective when operating in the exhaust temperature range of 480 to 800 °F. The minimum operating temperature of the catalyst is dependent on the composition of the exhaust gases and the type of catalyst materials used, and the typical exhaust temperature range for some lean burn engines may present challenges. Engines that have variable power loads require more sophisticated controls to inject the proper amount of reagent, and it is not evident that robust control schemes have been developed for transmission applications. The installation of a continuous emissions monitor could be required to effectively control the amount of reagent necessary to achieve the desired NOx emission rate.

SCR catalytic elements can be contaminated by byproducts of combustion (such as oil ash) and engine oil carryover. Cleaning and replacement is required on a periodic basis, and extra management is required to ensure adequate inventories of reagent are maintained.

Due to the issues described above and the desire to prevent NOx formation rather than controlling NOx in the exhaust, LEC is preferred over SCR for existing lean burn engines.

4.0 Reciprocating Engine Demographics (Population and Type)

An INGAA engine database (originally developed by PRCI and GRI over 10 years ago) includes 3665 *low speed* reciprocating engines used in the interstate natural gas industry. It should be noted that the number of engines in the tables below reflect large bore, low speed reciprocating engines. There are other engines used in the natural gas transportation industry. Most of the other engines are newer high-speed four-stroke cycle engines that are already equipped with low NOx emissions (typically LEC or NSCR) technology, such as best achievable control technology (BACT) required during permitting of new units or technology to meet New Source Performance Standards (NSPS) and National Emission Standard for Hazardous Air Pollutants (NESHAP) regulations.

Although this database is not complete (e.g., it was estimated to include over 80% of interstate transmission facilities when it was compiled), and changes in the fleet have occurred since the database was last updated, the information from this source still provides a reasonable basis to assess counts of existing engines and technology requirements for NOx control. Of the 3665 low speed engines, 35 are known to have been abandoned or replaced leaving a net of 3630 engines. These engines were categorized by engine type and geographical region as described in Section 5, where regulatory risk (i.e., likelihood and level of control) was used to categorize states into three regulatory risk categories depending on the state where the engine is located. Table 4-1 shows engine counts for each category for the three primary engine types. (The states in each risk category are identified in section 5.)

Table 4-1. Engine Type by Geographical Regulatory Risk Category.

Engine type	Category 1	Category 2	Category 3	Total
2-stroke cycle	321	1975	344	2640
4-stroke cycle lean	82	320	51	453
4-stroke cycle (rich)	50	405	82	537
Total	453	2700	477	3630

The average engine size is 2145 brake horsepower with an average of 12 power cylinders per engine. To assess technology requirements and potential resource issues, these engines have been grouped or classified based on different engine types/subtypes and current emission control capabilities. Each group type requires a different approach to NOx reduction with an associated impact on costs and schedules. The two-stroke cycle and four-stroke cycle lean engines are candidates for LEC and the four-stroke cycle rich burn engines are candidates for NSCR NOx control technologies. For the purposes of this discussion, the “rich burn” engines include older, horizontal engines that do not include air to fuel ratio control and may operate near stoichiometric conditions (i.e., “rich”) or leaner (i.e., with excess air). The term “stoichiometric” refers to the condition where the amount of oxygen available from the combustion air is equivalent to the amount required to completely combust all of the fuel without any excess oxygen. Rich burn engines operate near stoichiometric conditions, while lean burn engines have excess air. Regulatory definitions, such as the federal NSPS and NESHAP standards, typically

use ten percent excess air (which is equivalent to two percent excess oxygen in the exhaust) as the threshold between rich and lean operation.

To estimate the number of engines that would require NO_x emissions control, and assess associated capital costs and timeline, the INGAA database of engines was analyzed by current emission levels as shown in Table 4-2. Note that this table excludes 417 low BMEP four-stroke rich burn engines that are assumed to have NSCR catalysts as described in Section 4-2.

Table 4-2. Engine Counts by NO_x Emission Levels.

Emission capability	Category 1	Category 2	Category 3	Total
NO _x ≤ 1 g/hp-hr	64	0	0	64
1 < NO _x ≤ 3 g/hp-hr	339	162	36	537
NO _x > 3 g/hp-hr	0	2238	374	2612
Total	403	2400	410	3213

The majority of reciprocating engines used in the interstate natural gas transportation industry were installed before 1960. Most have been exempt from clean air regulations issued after they were installed since existing units are “grandfathered” – i.e., exempt from regulations that affect new sources. A common exception is engines that have been controlled in response to NO_x RACT or similar rules adopted to decrease the NO_x inventory from existing sources as a strategy to address ozone nonattainment. A discussion follows on each of the primary engine categories, related engine counts, and NO_x control technology available.

4.1 Horizontal engines

Horizontal engines are four-stroke cycle naturally aspirated engines with four double acting power pistons. These engines were manufactured by Cooper-Bessemer (Type 22 through Type 26) and Worthington (24X36 and 26X36). These engines are the first type of reciprocating engines widely used to compress natural gas for transportation. They are a derivative of horizontal steam engines. The double acting power cylinders (combustion occurs on both sides of the piston) have very large cylinder bores (22” to 26”) and strokes (typically 36”). It is difficult to control the air/fuel mixture for these units – e.g., for use with post-combustion catalytic control. Likewise, they are not suited to LEC conversion. Per the INGAA database, there are 120 engines in this group, where a retrofit NO_x control technology is not available, with an average power rating of 1530 hp.



Figure 4-1. Horizontal Engine

Because these engines have higher operating and maintenance costs, they are generally operated on a last on, first off basis in response to demand. Therefore, their annual operating hours tend to be lower than newer engines operating at the same facility.

Since technology upgrades are not available, the assumed “NOx control” option for these engines is replacement. For cost estimating purposes, the assumed replacement equipment is 3000-4000 hp gas turbines equipped with dry low NOx (lean premixed) combustors. Although larger gas turbines would reduce the capital replacement costs, smaller gas turbines are a better match (although still larger) to the engines being replaced. Larger engines do not have the necessary turndown capability to match the horizontal engines. Gas turbines were selected over other engine types due to the lower capital costs. Where minimizing fuel is a major consideration, high speed four-stroke cycle reciprocating engines would be selected as the replacement engine. All of these engines are located in geographical regulatory risk Categories 2 and 3 as shown in Table 4-3. These engines are a subset of the four-stroke rich burn engines found in Table 4-1. All horizontal engines are assumed to have NOx emission rates greater than 3 g/hp-hr.

Table 4-3. Number of horizontal engines.

Engine Type	Category 1	Category 2	Category 3	Total
4-stroke – horizontal	0	105	15	120

4.2 Low BMEP four-stroke cycle naturally aspirated engines

Like the horizontal engines, the low BMEP four-stroke cycle engines (see Figure 4-2) used in natural gas transmission sometimes operate near stoichiometric conditions and other times operate lean. These engines differ from horizontal engines in that they can generally be fitted

with air-fuel controls to enable operation with NSCR. However, depending on the units, operation with NSCR sometimes requires higher exhaust temperatures than the unit was initially designed. Alternative technologies include converting to LEC (with the addition of a turbocharger) [6] or installing SCR. SCR has had very limited application to existing reciprocating engines, and installation of SCR may limit the ability of the engine to operate at rated power.



Figure 4-2. Ingersoll-Rand KVG

The analysis in this report assumes that NO_x reductions would be achieved with installation of NSCR, with engine modifications completed as necessary to accommodate higher exhaust temperatures. However, existing rich burn engines at “major sources” (i.e., larger facilities such as compressor stations with multiple reciprocating engines) were required to install NSCR to comply with an EPA regulation, with compliance required by 2007 for the 2004 RICE NESHAP rule. Therefore, resource limitation were not assessed and costs to modify these engines are not estimated here because any incremental costs (e.g., to better tune the air to fuel ratio controller (AFRC) for NO_x reduction) should be minimal. It is likely that some of these engines will require control or additional modifications to achieve required NO_x reductions. The number of these engines in each geographical regulatory risk category can be found in Table 4-4. This is a subset of the four-stroke cycle rich burn engines in Table 4-1.

Table 4-4. Number of low BMEP four-stroke cycle engines.

Engine Type	Category 1	Category 2	Category 3	Total
4-stroke cycle low BMEP	50	300	67	417

4.3 Opposed piston two-stroke cycle engines

The gas pipeline transportation industry employs about 14 two-stroke cycle opposed piston engines such as the Fairbanks-Morse engine shown in Figure 4-3. These engines typically use superchargers to provide scavenging air.

The engines utilize two power pistons per power cylinder with intake and exhaust ports at opposite ends of the cylinder liner. The two pistons are connected to separate crankshafts which are synchronized through a vertical driveshaft and bevel gears. Because of the higher number of moving parts on these engines, they tend to have higher maintenance costs than other engines used in this industry.

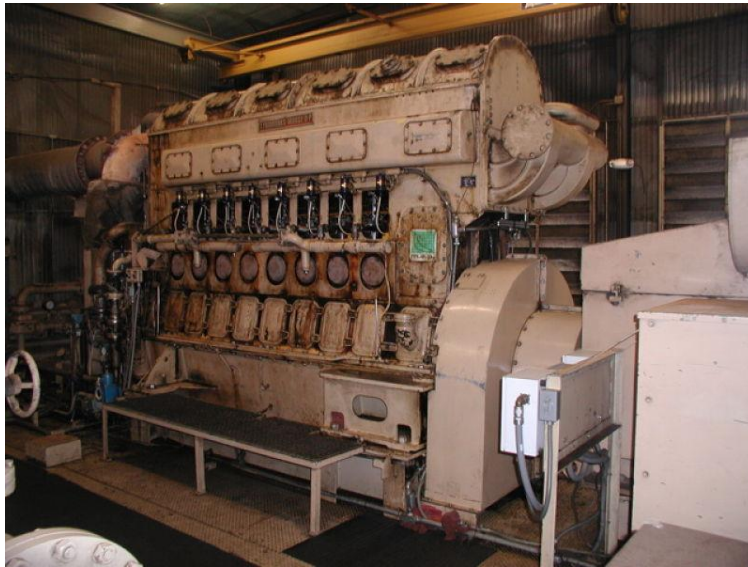


Figure 4-3. Fairbanks-Morse MEP-8

The engines can be converted to lean burn combustion or controlled using post-combustion catalytic reduction. NO_x emission rates below 3 g/hp-hr are difficult to achieve at full load and speed on these engines through lean combustion alone. Based on the operating cost of these engines and emission characteristics, the analysis in this report assumes emission reduction is achieved with lean burn conversion and an emission rate of 3 g/hp-hr. Replacement is assumed if lower emission rates are required. The location of these engines by geographical regulatory risk category is in Table 4-5. This is a subset of the two-stroke cycle engines in Table 4-1.

Table 4-5. Number of opposed piston two-stroke cycle engines.

Engine type	Category 1	Category 2	Category 3	Total
2-stroke cycle opposed piston	1	13	0	14

4.4 Medium and higher BMEP four-stroke cycle turbocharged engines

Medium and higher BMEP four-stroke cycle turbocharged engines (see example in Figure 4-4) operate too lean to utilize NSCR for NO_x reduction, and these engines are generally suited to

NO_x control through lean burn combustion and enhanced mixing methods – i.e., LEC technologies.



Figure 4-4. Ingersoll-Rand 616KVT

For cost estimating and resource availability assessment purposes in this study, reducing emissions to 3 g/hp-hr is assumed to be achieved through lean combustion. To lower NO_x emissions to 1 g/hp-hr requires the addition of enhanced fuel mixing. The assumed emissions and location of these engines by geographical regulatory risk category can be found in Table 4-6. This table is a subset of four-stroke cycle rich and four-stroke cycle lean engines in Table 4-1.

Table 4-6. Number of medium and higher BMEP four-stroke cycle turbocharged engines.

Emission type	Category 1	Category 2	Category 3	Total
NO _x ≤ 1 g/hp-hr	36	0	0	36
1 < NO _x ≤ 3 g/hp-hr	46	26	5	77
NO _x > 3 g/hp-hr	0	308	46	354
Total	82	334	51	467

4.5 Low BMEP two-stroke cycle engines

Low BMEP two-stroke cycle engines are generally older engines (i.e., the “first generation” of pipeline integral 2-stroke engines) that utilize low volume pumps or blowers to provide engine scavenging (Figure 4-5). To reduce NO_x emissions, LEC is applied through the removal of the mechanically driven scavenging and installation of turbochargers with after-cooling and precombustion chambers. Because of the low BMEP of these engines, there is typically less exhaust energy to support turbocharger operation. As a result, the power turndown range of converted units is limited. The addition of enhanced fuel mixing technologies would extend the power operating range for these engines.



Figure 4-5. Clark HBA Low BMEP Engine

Therefore, conversion to 3 g/hp-hr of NO_x is assumed to require both conversion to leaner combustion and the installation of enhanced fuel mixing. With these modifications, the engines are capable of achieving 1 g/hp-hr of NO_x in a narrower range near rated speed and power.

Adding a turbocharger sometimes allow these engines to operate at a higher rated power. This can increase the available turndown range of these engines as more heat energy is available to drive the turbocharger. Power increases of 5-40% are possible. The ability to increase the rated power of the engines is dependent on the design of the mechanical, structural, and auxiliary components (crankshaft, connecting rods, pistons, foundation, jacket water cooling, etc.) to handle the higher loads on the engine. The gas compressor cylinders may also require modifications to be able to utilize the additional power. This is usually achieved by installing larger compressor pistons and additional unloaders.

An increase of the engine power rating usually requires modifications to the air permit and filing with the Federal Energy Regulatory Commission. In some cases, the update of several engines could allow the abandonment of another engine thereby eliminating the need (and associated costs) to control emissions for that engine.

On a per horsepower basis, the costs of NO_x control conversion for these units are generally more than the costs for higher BMEP two-stroke cycle engines (discussed below). This is due to additional intake/exhaust manifold modifications and the installation (versus an upgrade) of a turbocharger/after-cooler system. The assumed emission limits and location of these engines by geographical regulatory risk category is shown in Table 4-7. This is a subset of the two-stroke cycle engines in Table 4-1.

Table 4-7. Number of low BMEP two-stroke cycle engines.

Emission type	Category 1	Category 2	Category 3	Total
$\text{NO}_x \leq 1 \text{ g/hp-hr}$	5	0	0	5
$1 < \text{NO}_x \leq 3 \text{ g/hp-hr}$	72	0	0	72
$\text{NO}_x > 3 \text{ g/hp-hr}$	0	461	44	505
Total	77	461	44	582

4.6 Medium and higher BMEP two-stroke cycle engines

Medium and high BMEP two-stroke cycle engines are engines that utilize centrifugal blowers and/or turbochargers to provide engine scavenging (Figure 6). These engines are generally larger than the first generation low BMEP 2-cycle engines discussed above. They are well suited to lean burn combustion to reduce NO_x formation. A reduction in the power operating range can be expected on some of these engines in order to maintain very low NO_x emissions. The addition of enhanced fuel mixing technologies extends the operating range of these engines and/or further reduces NO_x emissions.

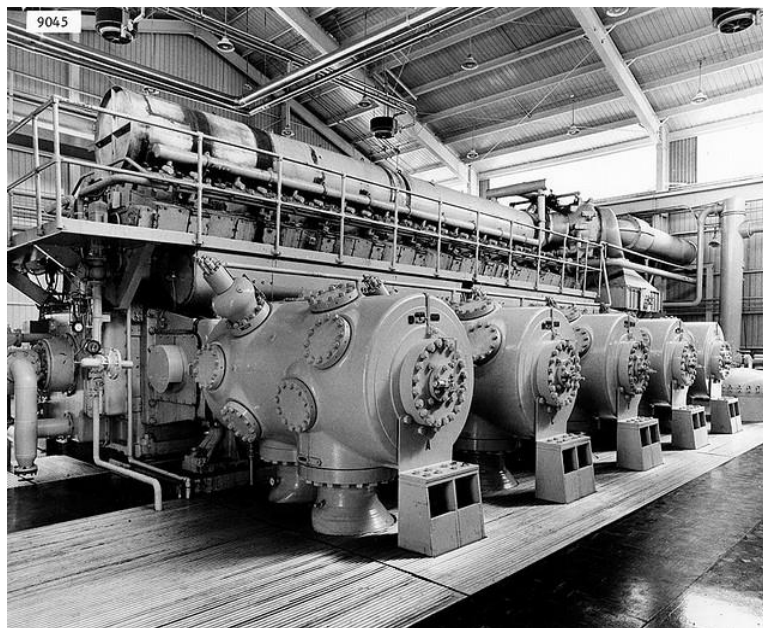


Figure 4-6. Cooper-Bessemer Z330

For the cost estimating purposes of this study, reducing emissions to 3 g/hp-hr is assumed to be achieved through lean combustion. This emission level is consistent with NO_x limits for retrofit control of lean burn engines in federal and status rules, and is an expected upper bound target in upcoming rules. However, it is possible that lower NO_x emission levels, such as 1 g/hp-hr limits, will be pursued in some jurisdictions. Lower emission limits also require the addition of enhanced fuel mixing. The assumed emission limits and location of these engines by geographical regulatory risk category is shown in Table 4-8. This is a subset of the two-stroke cycle engines in Table 4-1. Note that this group includes many engines, and often these engines are more highly utilized than smaller, older low BMEP engines discussed in the previous section.

Thus, the medium to high BMEP two-stroke cycle engines are a prime candidate for regulation when states or EPA consider NOx control regulations.

Table 4-8. Number of medium and high BMEP two-stroke cycle engines.

Emission type	Category 1	Category 2	Category 3	Total
$\text{NO}_x \leq 1 \text{ g/hp-hr}$	23	0	0	23
$1 < \text{NO}_x \leq 3 \text{ g/hp-hr}$	221	134	31	386
$\text{NO}_x > 3 \text{ g/hp-hr}$	0	1372	269	1641
Total	244	1506	300	2050

5.0 Regulatory Background and Analysis Assumptions and Methodology

NOx emission regulations continue to evolve and are not fully defined at this time. However, as EPA and the states implement regulations in response to ozone NAAQS nonattainment and the NO₂ NAAQS, it is expected that new regulations and permitting actions over the next 5 to 15 years will impact the status of many engines that are currently uncontrolled. The following section provides an overview of NOx regulations and regulatory risk, and section 5.2 discusses assumptions used to assess implications.

5.1 NOx Regulations – Background and Regulatory Risk

For existing equipment, NOx regulations are generally in response to concerns with ozone NAAQS nonattainment because NOx is an ozone precursor – i.e., it reacts in the atmosphere to form ozone. In addition, 2010 revisions to the NO₂ NAAQS increased the stringency of that rule. If offsite impacts (i.e., beyond the facility fence line) of NO₂ determined using a dispersion model exceed the NAAQS, then mitigation may be required. At this time, the most likely triggers for retrofit NOx control for natural gas transmission prime movers are:

- **NOx RACT Rules:** Revisions to the ozone NAAQS planned for 2014 – 2015 will likely increase the number of nonattainment areas, and result in new state-level NOx RACT rules later this decade. Such rules are highly likely to occur unless EPA provides a different regional solution, and state rules could result in different requirements and applicability (e.g., statewide or county-specific rule) from state to state. States tend to rely on rules developed by other states, so states that are early actors in the next few years could provide “model rules” that would be broadly implemented.
- **Regional Rule:** EPA may implement a broad (e.g., eastern half of U.S.) regional rule similar to the 2004 NOx SIP Call Phase 2 Rule that required NOx reductions from large sources. Over 200 natural gas-fired prime movers were controlled in response to the 2004 SIP Call Rule. A similar new regional rule could supplant or supplement state NOx RACT Rules (see previous bullet), could quicken the schedule, and would likely affect many eastern U.S. engines. EPA may be hesitant to pursue this (and instead defer to the states) due to legal issues that remain to be resolved with a regional rule for electric utilities.
- **NO₂ NAAQS mitigation:** To date, there have been minimal regulatory actions in response to the 2010 NO₂ NAAQS revision. However, example modeling has shown that the relatively short stacks common for reciprocating engines and conservatism in AERMOD (the regulatory

dispersion model) may result in offsite impacts that exceed the 100 ppbv 1-hour NO₂ NAAQS for uncontrolled reciprocating engines. Although there has been limited action to date, this could result in state or federal requirements to mitigate these impacts, and agency actions could be prompted by litigation or pressure from third parties. For existing facilities, EPA or the state could require modeling at any time, such as when the operating permit undergoes its five year renewal. Third party challenges could also force states or EPA to act regardless of the permit renewal schedule. This issue has the potential to impact many existing, uncontrolled reciprocating engine prime movers. Mitigation may require multiple measures, including NO_x control, increasing stack height, and/or increasing the property buffer (e.g., land purchase, moving the fence to the property line).

Regarding the ozone NAAQS, EPA planned to revise the NAAQS in 2011 in response to legal challenges. This was delayed and it was decided to complete the next revision under the schedule that requires NAAQS review every 5 years. That schedule currently plans for a proposed rule in the spring of 2014 and a final rule by mid-2015. That rulemaking will likely result in more nonattainment areas than under the current 75 ppbv NAAQS. This is illustrated in Figure 5-1 and Figure 5-2.

Nonattainment is determined by assessing whether the 3-year average value (from ozone monitoring) exceeds the NAAQS. Projected nonattainment areas from EPA maps in 2010 for an ozone NAAQS of 60, 65 or 70 ppbv are shown in the left map in Figure 5-1. Those ozone levels were being considered for the 2011 rule that was deferred. The right map shows actual ozone nonattainment areas determined in 2012 for the current 75 ppbv standard. The projections for 60 to 70 ppbv were based on 2006 – 2008 data. The nonattainment areas defined in 2012 are based on a 3-year average from 2008 – 2010 or 2009 – 2011. The eastern U.S. had a cool and wet summer in 2009, and hot, sunny weather is more conducive to ozone formation. Thus, states and third parties are challenging EPA and would like to plan for broader nonattainment and address NO_x transport from upwind states. Figure 5-2 shows an analysis completed by the Ozone Transport Commission, a group of 12 northeastern states that collaboratively assess air quality in that area. If 2009 data is excluded and the 3-year average is based on 2010 – 2012 data, the figure shows significantly more areas above 75 ppbv and also shows areas that would not achieve a lower, 70 ppbv standard.

Thus, if upcoming summers are not cool (like 2009), and EPA fulfills expectations to lower the ozone NAAQS to a level between 60 and 70 ppbv in 2015, nonattainment areas will more likely resemble the 60 – 70 ppbv map on the left in Figure 5-1; or, for the northeast, the map in Figure 5-2. This would result in either a broad regional NO_x control rule or requirements for many states to develop or update NO_x RACT regulations for existing sources.

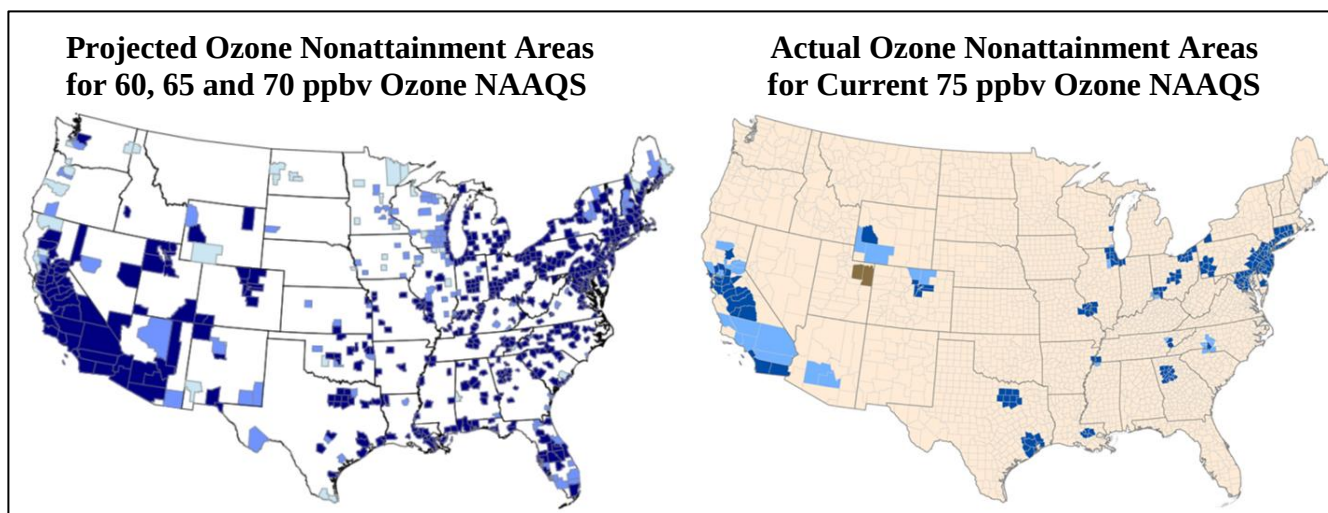


Figure 5-1. Projected ozone nonattainment areas (left map) for ozone NAAQS of 60 ppbv (light blue), 65 ppbv (blue) or 70 ppbv (dark blue) and actual ozone nonattainment areas (right map) for the 75 ppbv ozone NAAQS (dark blue – whole county; light blue – partial county; green – unclassifiable).

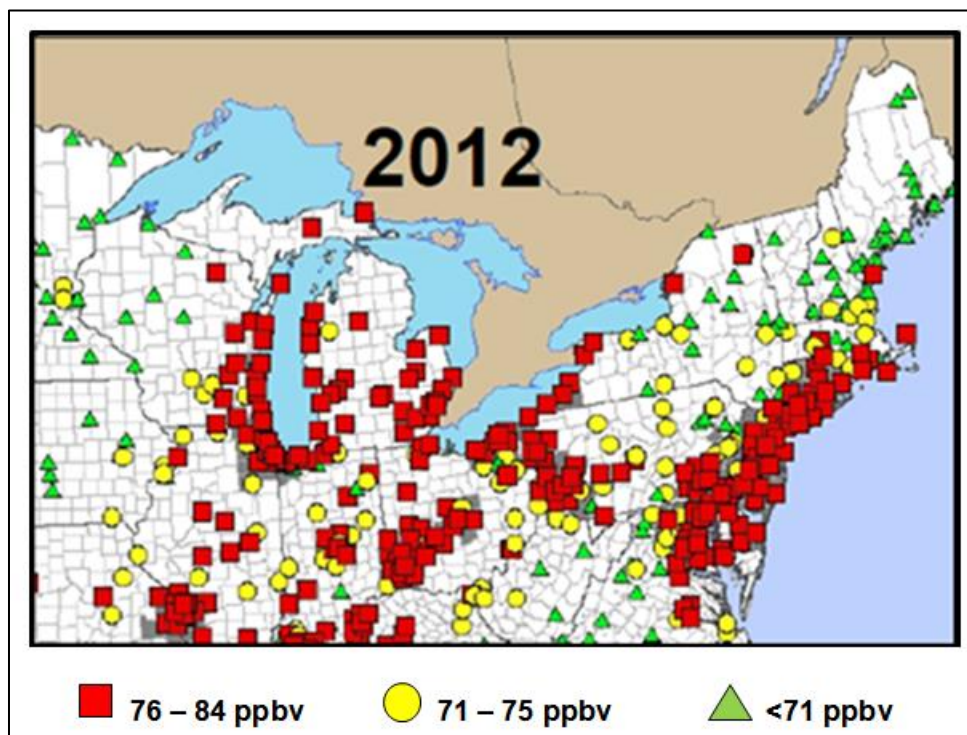


Figure 5-2. Updated northeast U.S. ozone air quality projections from the Ozone Transport Commission based on 2010 – 2012 ozone data (3-year average).

Regarding the NO₂ NAAQS, a committee of state and federal modelers has published example modeling results that show “typical” compression facilities with offsite impacts well above the NAAQS. [7] In Pennsylvania, a third party has requested that the state require modeling for all

compressor facilities based on an independent report presenting modeling results with impacts above the NAAQS. [8] To date, the state has provided analysis and data to justify not requiring such modeling, but additional third party challenges are likely. Thus, although requirements in response to the 2010 NO₂ NAAQS have not yet been common, the 2010 NO₂ NAAQS provides a platform for requirements that could broadly affect reciprocating engines that are not equipped with low NO_x technology.

Thus, although schedules and mandates are highly uncertain, implementation of current and pending regulations will likely require retrofit NO_x control (or replacement) for many existing natural gas-fired reciprocating engines. For this report, the specific timing and count of affected units was not defined. The analysis conducted, based on the actual engines in the fleet discussed in Section 4, focused on available resources and the cost and schedule to install controls based on NO_x endpoints of 3 g/bhp-hr or 1 g/hp-hr. These emission levels are based on anticipated emission limits for typical NO_x rules, with the lower limit based on potential requirements in more aggressive states.

In judging the likelihood of control and target NO_x level (i.e., 3 or 1 g/bhp-hr), states were divided into three categories based on a judgment of the risk of NO_x control and stringency over the next 5 to 15 years. This assessment was based on experiences with different states, proximity to areas that have previously failed to attain the ozone NAAQS or are expected to not attain if the ozone NAAQS is lowered in 2015, or within an area that has been targeted by eastern U.S. nonattainment areas as a “NO_x transport” area. When considering the time required to install NO_x controls, engine location and this ranking were considered (e.g., likelihood that a NO_x level of 1 g/hp-hr NO_x would be required). For assessing the likelihood of control and the NO_x endpoint (3 g/bhp-hr or 1 g/hp-hr), states were placed into one of three regulatory risk categories:

- Category 1 (high risk and stringency) – geographical region (i.e., states) where stringent NO_x emissions limits are already in place (e.g., northeast states, California, Colorado); if NO_x control is not in place, there is a high probability engine modifications will be required;
- Category 2 – geographical region where there is a moderate probability that lower NO_x emission limits will be required (e.g., Midwest and southeast states implicated as contributors to NO_x transport); and,
- Category 3 – geographical region with a lower probability that lower NO_x emission limits will be required.

The INGAA database includes engines in forty-one states, and the list of states and their ranking is shown in Table 5-1.

Table 5-1. Regulatory Risk Category for States with Engines in the Database.

State	Risk Category
Alabama	2
Arizona	2
Arkansas	2
California	1
Colorado	1
Connecticut	1
Florida	2
Georgia	2
Idaho	3
Illinois	2
Indiana	2
Iowa	3
Kansas	2
Kentucky	3
Louisiana	2
Maryland	1
Michigan	2
Minnesota	3
Mississippi	2
Missouri	3
Montana	3
Nebraska	3
New Jersey	1
New Mexico	2
New York	1
North Carolina	2
Ohio	2
Oklahoma	2
Oregon	3
Pennsylvania	1
Rhode Island	1
South Carolina	3
Tennessee	2
Texas	2
Utah	3
Virginia	2
Washington	3
West Virginia	2
Wisconsin	3
Wyoming	3

5.2 Assumptions and Methodology for Reciprocating Internal Combustion Engines (NOx)

The following assumptions and methods were used when assessing technology and resource requirements, schedules, and costs.

- Many rich burn engines employed in interstate natural gas transmission have been modified to reduce HAP emissions under the 2004 RICE NESHAP. Typically these four-stroke cycle rich burn engines added NSCR technology, including the associated engine air-to-fuel ratio control (AFRC). This technology also reduces NOx emissions. As such, four-stroke cycle rich burn engines were excluded from this analysis. It is believed that this is a reasonable assumption with the following caveats:
 - Some of the smaller four-stroke cycle rich burn engines or engines at small facilities may not have installed NSCR.
 - Some engines may require additional modifications or more attention to AFRC to meet NOx limits. This may be achieved by installing a larger catalyst or an upgraded AFRC.
- Some engines (i.e., horizontals) do not have suitable control technologies to reduce NOx emissions as they sometimes operate near stoichiometric conditions (rich) at full load and lean conditions at reduced load. These engines lack the ability to control the air to fuel ratio across the load range. In addition, the engines are of older designs that have limited parts availability and higher operating costs. For the purposes of this study, it is assumed these engines are replaced with new engines and the associated compressor and ancillary equipment. Specific engine types include:
 - Cooper-Bessemer four-stroke cycle horizontal engines, and
 - Worthington four-stroke cycle horizontal engines.
- Some of the engines in the INGAA database have been removed from service since the database was last updated. Those units were removed from the analysis where information was provided by the operator or the author had personal knowledge regarding those units.
- For cost estimating purposes, the following scope of work was assumed for NOx control:
 - 3 g/hp-hr NOx emission rate limit:
 - NOx control through low emissions combustion,
 - High energy ignition system is assumed to be precombustion chamber, either:
 - Screw-in, or
 - Head replacement;
 - Turbocharger modifications are required for lean combustion,
 - Turbocharger after-cooling enhancements are required, and
 - May or may not require (depending on engine model):
 - Fin fan after-cooler upgrades,
 - Coolant surge tank modifications,
 - Auxiliary generator upgrades,
 - Air inlet piping and filter modifications, and/or
 - Exhaust manifold, silencer, and exhaust stack modifications.

- Alternate or additive approaches (depending on the engine and emission target) include:
 - Enhanced mixing with or without high energy ignition system modifications, and
 - Post-combustion treatment utilizing SCR in select cases.
 - 1.0 g/hp-hr NOx emission rate limit:
 - Modifications for 3 g/hp-hr NOx as outlined above plus enhanced mixing and/or post-combustion treatment utilizing SCR.
- To identify those engines already controlled, existing emission capabilities were assumed based on descriptions and attributes in the INGAA engine database. Specifically, engines were assumed to be controlled to:
 - 3 g/hp-hr NOx or lower if:
 - The engine was identified as having low NOx emission controls,
 - The engine was identified as having post-combustion catalytic treatment (i.e., this implies that permitting closely scrutinized emissions),
 - The engine make and model number is known to be a low NOx emissions unit,
 - The engine is located in a state where control is already required for reasonably available control technology (RACT), or
 - The operating company and/or emission reduction vendor identified specific engines that have been modified to achieve low NOx emissions.
 - 1 g/hp-hr NOx or lower if the operating company and/or emission reduction vendor identified specific engines that were modified to be capable of this emission level.
- As discussed in Section 5-1 and shown in Table 5-1, U.S. locations were divided into three areas based on a judgment of the risk of NOx control requirements and stringency over the next 5 to 15 years.
- New air emission regulations or permitting requirements are expected to eliminate the grandfather provision in many cases and institute NOx control requirements for existing engines that currently are not controlled. The timing that the States (or other agencies) will implement NOx reduction rules and the level of NOx reduction cannot be defined at this time. For assessing the likelihood (and stringency) of control, States were categorized into three geographical regulatory risk categories as discussed above and shown in Table 5-1.
- To understand worst case scenarios in regards to the number of affected engines and a conservative cost projection, it was generally assumed that some level of control would be required for uncontrolled units. For example, engines in northern plains states that may not be affected by a regulation to address nonattainment could still require control to address NO₂ modeled impacts. In general, with the exception of the rich burn engines in Table 4-4, engine counts without controls (e.g., horizontal engines; engines >3 g/hp-hr) from Section 4 tables were included in the cost estimate and scheduling assessment, and additional engines (i.e., units currently controlled but with emissions between 1 and 3 g/hp-hr) are considered for the 1 g/hp-hr NOx limit, depending on location. These total over 2600 uncontrolled engines and over 500 engines that may require additional control if NOx requirements are reduced to 1 g/hp-hr. At this time, it is not expected that the lower NOx level would be

broadly required. So, while costs are estimated for the 1 g/hp-hr endpoint to provide that estimate in the report, the schedule to complete all retrofits judges the engine location when assessing the likelihood of a 1 g/hp-hr NOx requirement.

6.0 Cost and Schedule Estimates

The primary purpose of this report is to assess resource constraints associated with retrofit NOx control. In assessing technology requirements and resource constraints, costs were also determined. Cost and schedules are discussed in this section, and Section 7 discusses resource availability (i.e., skill sets and staffing) for each project phase. Information is tabulated for:

- Capital cost for NOx control to achieve NOx emissions of either 3 or 1 g/hp-hr (see Tables 6-1 and 6-2). Separate costs are shown for each emission level, and these costs are not incremental.
- Annual engine retrofits (or replacements) that can be completed based on *current* staffing levels for key technology and engineering service providers (see Table 6-3).
- Time required to complete retrofits (or replacements) for the projected engine counts, based on an emission level of 3 or 1 g/hp-hr and current staffing levels.
 - Table 6-2 shows the number of years required to control engines to 3 g/hp-hr.
 - Marginally longer time is required to achieve 1 g/hp-hr for some engine types. Table 6-5 shows the *incremental time required* to achieve the lower NOx limit.
- The regulatory risk “categories” shown in the tables are based on geographical assignment of regulatory risk by state as discussed in Section 5.1 and shown in Table 5-1.

6.1 Capital costs

The costs to modify or replace engines to reduce NOx emissions were gathered through interviews with operating companies, other published sources, and the author’s experience.

As described above, unit (engine and compressor) replacement was assumed for horizontal and in some cases opposed piston two-stroke cycle engines. Replacement units were assumed to be dry low NOx gas turbines. Replacement costs were estimated at a fixed cost per unit (\$1,800,000) plus a variable cost proportional to engine size (\$895/hp). In the case of horizontal and opposed piston two-stroke cycle units, one new turbine unit was assumed for every two units that were replaced.

In select cases where SCR was considered, costs were estimated at a fixed cost per unit (\$250,000) plus a variable cost proportional to engine size (\$375/hp). Lean burn combustion modifications were estimated at a fixed cost per unit (\$152,000) plus a variable cost proportional to engine size (\$725/hp). Because of additional turbocharger and after-cooling requirements for two-stroke cycle engines, multipliers for the variable costs (for lean combustion conversion only) are 1.22 and 1.08 for low BMEP and medium/high BMEP two-stroke cycle engines respectively.

Enhanced mixing modifications were estimated at a fixed cost per unit (\$235,000) plus a variable cost proportional to engine size (\$85/hp). When both lean combustion and enhanced mixing modifications are implemented at the same time (e.g., converting from > 3 g/hp-hr to <1 g/hp-hr)

costs were estimated at a fixed cost per unit (\$427,000) plus a variable cost proportional to engine size (\$785/hp).

Costs were assessed for affected engines to reduce emissions to 3 g/hp-hr. For reducing to less than 1 g/hp-hr, the additional costs were determined for further reducing emissions from these engines. In addition, costs were determined for additional engines that are already controlled to 3g/hp-hr that require additional reductions to achieve 1 g/hp-hr. Note that the costs to modify engines for NO_x control are significantly lower than the replacement costs. This is due in large part to the fact that both the engine and the gas compressor must be replaced if the engine is replaced. As a general rule, the replacement equipment has a lower overall unit efficiency¹ and therefore uses more fuel (and by correlation has higher CO₂ emissions) than the units they are replacing.

The total estimated NO_x control capital costs to modify reciprocating engines used in the natural gas transportation industry are summarized below. Table 6-1 represents the costs to reduce emission rates to less than 3 g/hp-hr, and Table 6-2 represents the costs to reduce emission rates to less than 1 g/hp-hr. For 3 g/hp-hr, total costs are nearly \$4 billion and “average” costs per unit for the different engine types were about \$1 to \$1.5 million for 2-stroke engines and \$2 million for 4-stroke engines. Replacement costs exceeded \$2 million per unit.

Note that these two tables are exclusive, i.e., the tables present costs to achieve either 3 or 1 g/hp-hr and are not to be added together. In addition, while many units may need to achieve NO_x limits on the order of 3 g/hp-hr, it is currently not expected that a large percentage of the fleet will need to achieve 1 g/hp-hr. For example, engines in higher risk areas (Category 1) are more likely to face the more stringent emission limit, while engines in lower risk Category 3 would be far less likely to require a 1g/hp-hr emission limit. Thus, costs to achieve 1 g/hp-hr NO_x are a conservative upper bound (i.e., broad NO_x regulations are more stringent than expected) for the engine fleet in the INGAA database.

Table 6-1. Costs to achieve 3 g/hp-hr (\$ in thousands).

Emission type	Category 1	Category 2	Category 3	Total
Horizontal engines	\$0	\$236,308	\$36,054	\$272,362
Opposed piston	\$756	\$14,311	\$0	\$15,067
Med & high BMEP 4-stroke	\$0	\$660,355	\$89,798	\$750,153
Low BMEP 2-stroke	\$0	\$685,751	\$65,811	\$751,562
Med & high BMEP 2-stroke	\$0	\$1,770,389	\$330,588	\$2,100,977
Total	\$ 756	\$3,367,114	\$522,251	\$3,890,121

¹ Generally reciprocating engines drive reciprocating compressors while gas turbine engines drive centrifugal compressors. As a general rule, reciprocating engines are more fuel efficient than gas turbines. Likewise, reciprocating compressors are generally more efficient than the centrifugal compressors. There are exceptions where the gas turbine unit is the more efficient option. An example would be a high speed, low BMEP reciprocating engine driving a reciprocating compressor with small valve flow area replaced with a gas turbine/centrifugal compressor.

Table 6-2. Costs to achieve 1 g/hp-hr (\$ in thousands).

Emission type	Category 1	Category 2	Category 3	Total
Horizontal engines	\$0	\$236,308	\$36,054	\$272,362
Opposed piston	\$2,108	\$38,100	\$0	\$40,208
Med & high BMEP 4-stroke	\$18,235	\$807,287	\$111,779	\$937,301
Low BMEP 2-stroke	\$24,290	\$629,647	\$60,415	\$714,352
Med & high BMEP 2-stroke	\$94,840	\$3,645,435	\$680,204	\$4,420,479
Total	\$ 139,473	\$5,356,777	\$888,452	\$6,384,702

6.2 Schedule

Starting in 1999 as part of the NO_x State Implementation Plan (SIP) Call (an eastern U.S. regional NO_x rule for large existing sources), approximately 200 natural gas transmission engines were converted to LEC. From interviews with the operators and the emission reduction equipment suppliers, the conversion process took six years in total to fully implement. Additional engines were controlled in the late-1990's through about 2009 in response to state RACT rules.

Based on interviews with pipeline operations and emission reduction equipment suppliers having experience with previous conversion projects, NO_x control for each engine requires between 1 and 2 ½ years to complete (from inception to completion of commissioning). The longer duration projects are those that require more infrastructure modifications (such as cooling equipment and auxiliary generators), on-engine modifications (after-coolers, turbochargers, lubrication systems, cooling systems, fuel systems, pre-chambers, intake/exhaust systems, and controls), and engine overhaul. Generally, older engines require more time to design the conversion. This is due to inaccurate or missing engineering records on the current configuration of and ancillary equipment used on the engine.

Taking into account both the lead time and conversion time and based on *currently available resources* (i.e., trained personnel), the average number of units that can be modified to lean combustion on a sustained basis is **approximately 75 engines per year**. This is the key resource constraint that will affect NO_x control requirements that affect these engines, even if only a subset of engines (e.g., a quarter of the current total capacity) is affected by new NO_x control rules. Note that this projection is somewhat higher than the approximately 50 units per year converted under the NO_x SIP Call even though additional technical resources are not in place at this time. The higher number of units converted per year assumes some efficiency of scale will be achieved based on processes and standards developed from previous efforts. A relatively optimistic projection for the annual number of conversions was selected so that the analysis reflects an “optimistic” scenario without considering how staffing and training will respond to market demand.

The estimated number of engines that can be retrofit per year is based on *current* resource availability. While a dramatic increase in market demand would likely result in hiring and training of additional resources, the special skills associated with this niche market would require time to build that resource. In addition, until new regulations are adopted the market and timing is not clear, thus this resource base will not grow until the market is clear.

Based on the engine counts in Section 4 and the regional location of the engines, an estimate of the number of engines that can be modified per year is shown in Table 6-3, and the resulting number of years necessary to address NOx controls for the reciprocating engines used in natural gas transmission is presented in Tables 6-4 and 6-5.

The number of engines that can be modified per year depends on differences in scope related to the engine type (e.g., some engines are configured for lean combustion while others are not). The estimated number of engines that can be modified per year by engine type and emission level is shown in Table 6-3. The count varies for different engine types and emission level due to the complexity of the retrofit (e.g., need for additional equipment such as turbochargers, need to upgrade ancillary support such as cooling, etc.). It is not anticipated that the number of annual engine conversions can be significantly improved upon within a short timeframe (e.g., if demand for NOx control significantly and quickly increases) because specific skills and specialized training are necessary to serve this market.

Table 6-3. Estimated number of engines that can be modified/replaced per year.

Engine type & initial emissions	Modified to achieve NOx emission levels of:	
	≤ 3 g/hp-hr	≤ 1g/hp-hr
Horizontal engines	40	40
Opposed piston	40	40
Med & high BMEP 4-stroke > 3 g/hp-hr	75	64
Med & high BMEP 4-stroke ≤ 3 g/hp-hr	N/A	82
Low BMEP 2-stroke > 3 g/hp-hr	60	50
Low BMEP 2-stroke ≤ 3 g/hp-hr	N/A	75
Med & high BMEP 2-stroke > 3 g/hp-hr	75	64
Med & high BMEP 2-stroke ≤ 3 g/hp-hr	N/A	80

Based on the number of engines to be controlled (engine counts from the INGAA database as shown in Section 4) and the estimated number of engines that can be modified per year, the estimated time required to implement modifications to achieve 3 g/hp-hr is shown in Table 6-4.²

For NOx levels of 1 g/hp-hr, far fewer engines will be affected. To provide an upper bound on capital costs for control, costs in Table 6-2 were estimated assuming that all of the affected units would need to achieve the low NOx level. The schedule to achieve the lower NOx level and timing presented in Table 6-5 considers a much smaller subset of engines, such as engines in a high risk location such as the northeast (Category 1). While Table 6-2 shows the costs to control all engines to 1 g/hp-hr, Table 6-5 shows the nominal *incremental time* required for this smaller subset of “high regulatory risk” engines to achieve 1 g/hp-hr.

² While the elapsed time for an engine retrofit or replacement from inception to completion may take 1-2 calendar years, the work can be performed by multiple engineering firms and construction companies resulting in an average resource time of less than one year per project.

Based on current technical resources, the projected time to implement retrofit NOx control (or replacement) is far in excess of typical regulatory schedules. Primarily due to the large number of engines in Category 2 (units primarily in southeast and midwest states), *Table 6-4 shows that it would take **decades** to address NOx controls for a large number of engines*, even if the annual rate of retrofit conversions is doubled. Since the retrofit market is currently very limited (i.e., rules are not currently requiring installation of retrofit NOx controls), *there is no incentive to increase capacity* at this time. So, this limitation will not be addressed until indicated by market demand and confirmed regulations. Section 7 includes additional discussion of manpower and other resource constraints on a project level basis.

Table 6-4. Time required to modify engines to achieve 3 g/hp-hr (in years)³

Emission type	Category 1	Category 2	Category 3	Total
Horizontal engines	0.00	2.6	0.4	3.0
Opposed piston	0.03	0.3	0.00	0.3
Med & high BMEP 4-stroke	0.00	4.1	0.6	4.7
Low BMEP 2-stroke	0.00	7.7	0.7	8.4
Med & high BMEP 2-stroke	0.00	18.2	3.6	21.8
Total	0.03	32.9	5.3	38.2

A small number of engines (e.g., in Category 1) may require control to the more stringent 1 g/hp-hr NOx level. Table 6-5 shows the *incremental* time required to address that more stringent mandate and shows minimal impact on schedule to achieve the lower NOx level. However, considering capital costs in Tables 6-1 and 6-2, a lower NOx limit will have a significant cost impact, with engine-specific costs on average about 65% higher to achieve 1 g/hp-hr.

Table 6-5. Incremental time required to modify a subset of high risk engines to 1 g/hp-hr rather than 3 g/hp-hr (in years).

Emission type	Category 1	Category 2	Category 3	Total
Horizontal engines	0.00	0.07	0.01	0.08
Opposed piston	0.00	0.01	0.00	0.01
Med & high BMEP 4-stroke	0.00	0.06	0.01	0.07
Low BMEP 2-stroke	0.00	0.15	0.01	0.16
Med & high BMEP 2-stroke	0.00	0.28	0.06	0.34
Total	0.00	0.57	0.09	0.66

³ Unless resource constraints are addressed via staffing and training, the overall timeline cannot be shortened by executing the projects for multiple regions/engine types simultaneously. For example, replacing all of the horizontal engines in Categories 2 and 3 will take about 3 years even if the work for both categories is performed at the same time. This is because executing projects in Category 3 states concurrently with projects in Category 2 states will require the reallocation of resources away from Category 2 states.

7.0 Resource Analysis and Limitations by Project Phase

This section discusses resource requirements and constraints chronologically by project phase. The resource considered in this section is available manpower – i.e., staffing and expertise by topical area. All phases of project planning and execution are discussed even though several have minimal impact on schedule or cost. The information gathered identified several constraints and concerns associated with the available resources to implement NO_x emission reduction projects. Constraints are due to the availability of skilled or expert staff necessary to complete key project tasks, and the requirements and limitations are discussed qualitatively by project task.

Interview subjects included multiple operating companies and six different suppliers of equipment and services to modify natural gas transmission reciprocating engines.

7.1 Permitting

The permitting portion of the project typically involves evaluating many different cases. Design iterations are made to determine technology requirements to reduce emissions to required levels within the required timeframe. Secondary factors include the impact the proposed retrofit NO_x control technology has on equipment efficiency and operational turndown. Due to the workload of the permitting agencies, the permitting process typically takes a long time to complete (months to years in some cases). Because of the long lead time involved, air quality permit applications are often filed before design optimization for the NO_x control equipment can be completed.

Complicating factors may include other regulatory limits. For example, implementing significant modifications to a piece of equipment to reduce air emissions may require modifications to reduce noise emissions to conform to local noise regulations. In addition, special care must be made to ensure retrofitting NO_x control technology does not adversely impact emissions of other pollutants such as THC and CO, or additional controls (i.e., oxidation catalyst for CO or hydrocarbons) are considered to address this situation.

The operators expressed concern that regulations to reduce NO_x emissions will result in constraints at the state regulating agencies (e.g., timing to process permits and potential backlog due to state budget and staffing issues). The result could include:

- Slow response time in issuing air permits. This can result in delays to the project execution schedule, and can make it difficult to comply with new regulations with a hard deadline for implementation.
- Limited flexibility in approving new emission reduction technologies (i.e., time constraints due to agency staffing).
- Limited ability to modify the design for optimization after the permit application has been submitted without causing further delays.

These concerns could be mitigated somewhat if longer or phased implementation schedules are allowed. States generally propose a short compliance schedule (e.g., 18 months to two years from the rule date). It is incumbent upon the affected industry to try to convince the state during rule development to allow longer schedules, including phased schedules. Thus, operators need to

be proactive in working with states (or EPA) to achieve “reasonable” schedules. However, it is highly unlikely that a decades long implementation scenario indicated by Table 6-4 will be achievable.

7.2 Initial design

Based on the expected number of engines to be modified, pipeline operating companies will require additional engineering staff to perform initial design of NOx reduction modifications. Some of this will be achieved through the hiring of additional staff. However, based on the current trends and practices, most of this resource will be provided by firms that provide contract engineering services or turnkey solutions from LEC technology providers. Examples include: Black & Veatch, E-N Engineering, Mustang Engineering, Cameron, Dresser Rand, Hoerbiger, GE Oil and Gas, and many others. The experience and knowledge of these engineering firms for retrofit NOx control projects is varied and in most cases is limited. This is due in part to high turnover that occurs in these firms and the wide variability of equipment to be modified. The use of engineering staff additions and/or engineering services will require a significant learning curve and training. This will require more time to execute initial engine modification designs. As experience improves over time, the project execution duration should be reduced.

During this phase of project execution, providers of emission reduction equipment such as Cameron, Dresser Rand, and Hoerbiger will receive numerous requests for potential options for emission reduction technologies. This is especially likely where:

- Very low emission rates are required,
- Few engines of the make/model have previously been modified for low NOx technology,
- The engine has a unique design and configuration that requires specialized engineering analysis, and/or
- The engine is required to operate in special modes (e.g., requires a wide power range).

This demand for quotes is a potential resource constraint for the emission reduction equipment providers, especially when demand initially increases. In general, the unique attributes associated with legacy integral reciprocating engines provide a common theme regarding personnel / expertise based constraints. If regulatory timelines can be extended for projects that are unique in design or configuration, this can be mitigated.

Some emission reduction equipment providers will provide turnkey services (design, procure, construct, commission). However, there are currently only a handful of companies that provide this service for NOx control of legacy integral units. The number of engines modified using turnkey services will be limited to what emission reduction equipment providers can provide with moderate increases in qualified technical staff through using contract employees, part time staff, subcontractors, and retirees.

7.3 Procurement

Provided adequate personnel resources and experience exist in the initial design phase to produce procurement specifications, the actual procurement process should have minimal resource constraints. Qualified procurement personnel are available on a contract basis. In many cases,

the pipeline operating company will use the same contract engineering services to perform the procurement process.

Discussions with NOx emission control equipment suppliers indicated that manufacturing production can be increased to provide the equipment within a reasonable time period (assumed to be *at least 3 years*). As such, the procurement of the hardware required for NOx emission reduction projects is not expected to be a constraint as long as reasonable regulatory schedules are negotiated, trends for increased demand are understood, and production responds accordingly.

7.4 Cost estimating and scheduling

The cost estimating and scheduling phase typically use the same resources used in the initial design. This phase is not expected to have a significant resource constraint.

7.5 Detailed design

Detailed design for emission reduction projects will encounter much of the same resource constraints as described under initial design. The difference in this phase is more resources will be required to produce engineering drawings and project specification documents. Like the initial design phase, this will be achieved through a mix of additional employees for the pipeline operating company, contract services, and turnkey providers, with turnkey LEC technology companies the predominant resource – unless rapid growth in market demand prompts an alternative in the future.

At this phase of the project, the pipeline operating company will require additional resources to provide detailed project management oversight for the life of the project. Again, this will likely be achieved through the use of a mix of new employees and contract services with an associated training and learning curve period.

7.6 Construction

Pipeline operating companies and turnkey emission reduction vendors typically use contract construction services to implement the physical modifications to engines. These resources are generally available and should not be a constraint unless there are a number of major pipeline construction projects that would overlap with the timing of the engine emission reduction projects. Review of the potential for competing infrastructure projects is beyond the scope of this report, but other studies are available, such as the INGAA Foundation Report on midstream infrastructure projections through 2035. [9]

There is one exception; there is currently a shortage of welders qualified for natural gas piping. Modifying a large number of engines to reduce NOx emissions (e.g., 25%, 50%, or possibly the vast majority of over 2600 engines identified in Section 4) would further constrain this resource. Increasing the timeline available to implement engine modifications and avoiding an overlap in the execution of those projects with major pipeline expansion projects would help mitigate this constraint.

During the construction period, the equipment is not available for the transportation of natural gas. To minimize the impact on pipeline capacity and associated disruption for shippers, outages are optimized by:

- Scheduling the construction during periods of low system demands (such as during the summer for pipeline systems that have peak demands during the winter heating season),⁴
- Scheduling outages such that only one or two engines are out of service at any one station during any period of time, and
- Scheduling outages such that outages at compressor stations are staggered (e.g., start with outages at Stations A, C, E, & G, and when the modifications at those stations are completed, then Stations B, D, F, & H)

Future PHMSA regulations [10] may require pipeline operators to complete hydrostatic testing of pipelines (e.g., those installed prior to 1970). If the schedule to install NOx controls overlaps with other pipeline regulations, a reduction in available pipeline capacity may occur. This is exasperated by the overlapping vintage of the pipe that may be affected by PHMSA rules and the compressor engines likely to require NOx control. The result could result in shortages of natural gas in some areas of the country. To mitigate this possibility, it is important to understand not only air quality (or safety) regulatory schedules, but possible implications from different compliance activities across all regulations that occur in the same timeframe. Possible implications from overlapping requirements need to be communicated to regulators to try to avoid impacts on pipeline capacity and natural gas delivery.

7.7 Commissioning and Start-up

Proper commissioning of NOx reduction equipment is critical to assure the modified engine reliably meets air emission limits. The process of commissioning and safely placing into service an engine with new NOx control technology requires many different skills and specialized equipment, including:

- Engine mechanical specialist to tune the operation of the engine and equipment to measure the developed engine power,
- Control technicians to calibrate additional measurement points, verify pump rotations, etc.,
- Control system specialists to modify control software (to accommodate additional measurement points and control algorithms) and tune control loops,
- Qualified operating personnel to safely introduce fluids and energize systems,
- Subsystem specialists with specific expertise in control valves, gas measurement, and communications,
- Air emissions testing equipment and analysts, and
- Specialists to train the equipment operators on the operation and maintenance of the new equipment.

Due to the specialized skills required during this phase and expectations that demand will exceed the currently available resources, these are personnel resources that are likely to be constrained

⁴ With the increase in the number of natural gas fueled power plants installed over the last decade, many interstate pipelines that historically had peak loads during the winter heating season now also have peak demand periods in the summer. Off peak periods for these pipelines are now during the spring and fall.

for NOx control projects. Mitigation measures include utilizing available temporary resources (such as qualified contractors and retired employees), hiring and training new staff, and extending the timeline for modifications.

7.8 Operation and Maintenance

Within the first year after commissioning an engine, additional adjustments are commonly required after break-in and to address changes to seasonal ambient conditions. This typically requires the same technical personnel and equipment used to commission the engine as discussed above. The same mitigation measures described above would apply to operation and maintenance of the equipment.

If adequate operating spares for the newly installed equipment are purchased as part of the project, material resources should not be a constraint.

8.0 Conclusions

There is a great deal of uncertainty about the breadth (i.e., how geographically broad), depth (i.e., stringency of the rule), and schedule for new NOx regulations that will affect existing natural gas-fired reciprocating engines. Litigation and scheduling delays have slowed the regulatory process. Although the timing and breadth of new NOx control regulations remains uncertain, it is likely that many of the natural gas-fired reciprocating engines in the existing prime mover fleet will require NOx control by 2025. There are several thousand legacy natural gas-fired reciprocating engines driving compressors in interstate transmission, and their location (i.e., in rural areas where emission rules are more rare) and history (i.e., operating prior to rulemakings that affect new equipment) make these engines candidates for future regulation.

Based on previous projects and interviews with industry experts, modifying these engines will require significant time and capital. The capital required to address the fleet of engines without low NOx technology is significant. In addition, the lack of available expertise is likely to be a primary constraint in addressing broad, new regulations on a timely basis.

Based on interviews with operators, equipment vendors, and service providers, the primary conclusions from this study include:

- The special technical expertise to design, construct, and commission emission reduction projects for the low speed integral engines prevalent in natural gas transmission is available from a handful of companies, and with few NOx rules being adopted in recent years, this expertise may be migrating to other markets. Regulations that require installation of NOx control on a large number of reciprocating engines will require a significant lead time to train and develop resources to implement emission reduction projects. For example, if upcoming NOx regulations impact 25% of the current fleet of legacy reciprocating engines, the number of units requiring NOx control (over 600) would exceed the total number of units that have been controlled over the last 20 years. A higher percentage could be impacted (e.g., 50% of units affected is over 1300 units; even high impacts are possible), and market demand could significantly exceed the available resource base of skilled professionals.
- **Availability of this special technical expertise and building this resource is the primary resource constraint that will affect the ability to meet regulatory obligations that affect**

a large percentage of the fleet. Based on current capabilities and a scenario where NO_x regulations broadly affect the existing fleet of uncontrolled reciprocating engines, the estimated time to complete upgrades to over 2600 engines is nearly forty years.

- Although regulations may affect a smaller subset of engines or compliance strategies may result in many engines (e.g., lower horsepower, lower use engines) being retired or replaced, schedule implications due to the lack of available expertise will likely extend far beyond the required regulatory timeline (e.g., 1000 engines would require 15 years).
- There is no incentive to begin to build this resource base until it is clear that a market will exist – i.e., the regulations and associated schedule are in place. Since lawsuits and EPA priorities have slowed the next cycle of NO_x regulations, it is not possible to project the timing, stringency, number of affected units, or schedule for implementing new NO_x rules.
- In addition to regulatory risk associated with NO_x rules in response to nonattainment with the ozone NAAQS, revisions that increased the stringency of the NO₂ NAAQS in 2010 could trigger new NO_x control requirements for existing facilities through the permitting process – e.g., during permit renewal. This issue has the potential to trigger NO_x control requirements *sooner* than the current ozone NAAQS timeline.
- Due to this resource constraint, it is imperative that companies engage state and federal regulators when NO_x rulemakings commence. Emission regulations typically allow only one to two years to implement controls, and additional time and phased implementation will be needed to provide a more reasonable schedule. However, once the next round of NO_x rules are initiated, it is unlikely that a decade(s) long schedule will be allowed. The schedule conflicts associated with regulatory timelines, market demand, current supply (i.e., available resources), and service provider growth will likely present a significant challenge over the next 5 to 10 years.
- Engine NO_x control projects are generally much less costly than engine replacement. Capital costs to modify the fleet of currently uncontrolled reciprocating engines used in the interstate natural gas transmission industry are estimated at \$3,890 million and \$6,385 million to achieve NO_x emission rates of 3 g/hp-hr and 1 g/hp-hr respectively.
- The age of the impacted equipment (most of the engines are over 40 years old) requires additional time to engineer and construct reliable emission reduction modifications due to inaccurate or missing engineering records that reflect the current equipment configuration.
- Some engines with low specific power output will require extra time to properly design and construct emission reduction modifications and maintain the same power operating range.
- Based on previous experience, the timeline to obtain air permits is a key parameter defining the overall schedule for completing a specific emission reduction project – i.e., permitting can slow the project timeline.
- Equipment outages to implement emission reduction modifications may have a significant impact on available pipeline capacity, especially if the timeline overlaps with implementation of other regulations, such as pipeline integrity assessments that may be required by PHMSA.

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Appendix A: Acronyms

AFRC	Air to Fuel Ratio Controller
BACT	Best available control technology
BHP	Brake horsepower
BMEP	Brake mean effective pressure
CO	Carbon monoxide
EPA	Environmental Protection Agency
g	Grams
hp	Horsepower
Hr	Hour
INGAA	Interstate Natural Gas Association of America
LEC	Low emission combustion
MACT	Maximum achievable control technology
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standard for Hazardous Air Pollutants
NO₂	Nitrogen dioxide
NO_x	Nitrogen oxides
NSCR	Nonselective catalytic reduction
NSPS	New Source Performance Standard
O₂	Oxygen
PHMSA	U.S. Dept. of Transportation Pipeline and Hazardous Materials Safety Administration
RACT	Reasonably available control technology
RICE	Reciprocating internal combustion engine
SCR	Selective catalytic reduction
SIP	State implementation plan (Dresser-Rand and others also use “SIP” for screw-in pre-chamber.)
THC	Total unburned hydrocarbons
VOC	Volatile organic compounds (For gas-fired combustion, VOCs are THC excluding methane and ethane, which are the two most prevalent exhaust hydrocarbons). Formaldehyde is also a VOC but is excluded from some regulations (e.g., it is more difficult to measure than THC and may not be included in data used to establish a VOC standard or emission limit).

Appendix B: Survey Questions for Operator and Service Provider Interviews

1. Over the last three years, approximately how many engines has your company modified (as prime contractor) to meet emission levels of 3 g/hp-hr or less?
 2. How many of those modifications were achieved through lean emission reduction?
 3. Over the last three years, approximately how many engines has your company supplied parts, equipment, material, start-up support, or training to operating companies so they could modify their engines to meet emission levels of 3 g/hp-hr or less?
 4. Over the last three years, approximately how many engines has your company supplied parts, equipment, material, start-up support, or training to other vendors or contractors so they could modify their engines to meet emission levels of 3 g/hp-hr or less (acting as a subcontractor)?
 5. Over the last three years, approximately how many engines has your company modified (as prime contractor) to meet emission levels of 1 g/hp-hr or less (this should be a subset of (1) above)?
 6. How many of those modifications were achieved through lean emission reduction (this should be a subset of (2) above)?
 7. Over the last three years, approximately how many engines has your company supplied parts, equipment, material, start-up support, or training to operating companies so they could modify their engines to meet emission levels of 1 g/hp-hr or less (this should be a subset of (3) above)?
 8. Over the last three years, approximately how many engines has your company supplied parts, equipment, material, start-up support, or training to other vendors or contractors so they could modify their engines to meet emission levels of 1 g/hp-hr or less (acting as a subcontractor) (this should be a subset of (4) above)?
 9. Estimate average number of employees and subcontract staff (i.e. full time equivalent positions) utilized to support the emissions reduction projects over the last three years.
 10. Over the last three years, the qualified staffing to support emission reduction projects has:
 - a. Increased significantly
 - b. Increased some
 - c. Stayed about the same
 - d. Decreased some
 - e. Decreased significantly
-

11. Based on current staffing, estimate the number of projects per year your company can support acting as the prime contractor.
12. Based on current staffing, estimate the number of projects per year your company can support acting as a subcontractor/parts provider.
13. Based on the technical skills required, estimate the time required to hire and fully train new staff to support emission reductions projects:
 - a. Up to six months
 - b. Six months to one year
 - c. One to two years
 - d. More than two years
14. Please describe any issues or concerns associated with implementing a large number of emission reduction modifications over a three year time span.

MEMORANDUM

DATE: April 28, 2006

SUBJECT: Control Costs for Reciprocating Internal Combustion Engines at Major and Area Sources

FROM: Bradley Nelson, Alpha-Gamma Technologies, Inc.

TO: Jaime Pagán, EPA Energy Strategies Group

The purpose of this memorandum is to present information on the costs of control technology options for reducing hazardous air pollutants (HAP) emissions from stationary reciprocating internal combustion engines (RICE).

Introduction

The EPA has determined that oxidation catalysts, catalyzed diesel particulate filters (CDPF), and non-selective catalytic reduction (NSCR) are applicable controls for HAP reduction from stationary RICE. Equipment cost information from a vendor was obtained and used to calculate cost equations for oxidation catalysts and NSCR. The cost equations were used to estimate the national impacts of controlling emissions from existing and new engines. Cost information developed by the California Air Resources Board (ARB) for the Airborne Toxic Control Measure for stationary compression ignition (CI) engines and costs developed for the proposed new source performance standards (NSPS) for stationary CI engines were used to estimate costs for installation of CDPF on existing and new engines, respectively.

Methodology for Determining Cost Equations

The EPA determined that CDPF, oxidation catalysts, and NSCR are applicable controls for the reduction of HAP emissions from RICE. This is based on the theory that HAP reduction will only occur if an oxidation process occurs. At the time of this memorandum, these are the only known add-on control technologies that utilize oxidation. The following sections describe how the capital and annual costs for these control technologies were derived.

The capital and annual costs were determined using the Office of Air Quality Planning and Standards (OAQPS) Control Cost Methodology described below:

Determine:

- 1 - Total Capital Costs
- 2 - Total Annual Costs

1 - Total Capital Cost Components and Factors:

Total Capital Cost (TCC) = Direct Costs (DC) + Indirect Costs (IC)

1.1 - Direct Costs (DC): $DC = PEC + DIC$

1.1.1 - Purchased Equipment Costs (PEC):

- Control Device and Auxiliary Equipment (EC)
- Instrumentation (10% of EC)
- Sales Tax (3% of EC)
- Freight (5% of EC)

$PEC = 118\% EC$

1.1.2 - Direct Installation Costs (DIC)

- Foundations and Supports (8% of PEC)
- Handling and Erection (14% of PEC)
- Electrical (4% of PEC)
- Piping (2% of PEC)
- Insulation for Ductwork (1% of PEC)
- Painting (1% of PEC)

$DIC = 30\% PEC$

$DC = PEC + 0.3 PEC = 1.3 PEC$

1.2 - Indirect Costs (IC): $IC = ICC + C$

1.2.1 - Indirect Installation Costs (IIC)

- Engineering (10% of PEC)
- Construction and Field Expenses (5% of PEC)
- Contractor Fees (10% of PEC)
- Startup (2% of PEC)
- Performance Test (1% of PEC)

$$\text{IIC} = 28\% \text{ PEC} = 0.28 \text{ PEC}$$

1.2.2 - Contingencies (C) (3% of PEC)

- Equipment Redesign and Modifications
- Cost Escalations
- Delays in Startup

$$\text{C} = 3\% \text{ PEC} = 0.03 \text{ PEC}$$

$$\text{IC} = 0.28 \text{ PEC} + 0.03 \text{ PEC} = 0.31 \text{ PEC}$$

$$\text{TCC} = 1.3 \text{ PEC} + 0.31 \text{ PEC} = 1.61 \text{ PEC} = 1.61 (1.18 \text{ EC}) = 1.9 \text{ EC}$$

2 - Total Annual Cost Elements and Factors

$$\text{Total Annual Cost (TAC)} = \text{Direct Annual Costs (DC)} + \text{Indirect Annual Costs (IC)}$$

2.1 - Direct Annual Costs (DC):

- Utilities
- Operating Labor
- Maintenance
- Annual Compliance Test
- Catalyst Cleaning
- Catalyst Replacement
- Catalyst Disposal

2.2 - Indirect Annual Costs (IC)

- Overhead (60% of operating labor and maintenance costs)

- Fuel Penalty
- Property Tax (1% of TCC)
- Insurance (1% of TCC)
- Administrative Charges (2% of TCC)
- Capital Recovery = $[I*(1+I)^n / ((1+I)^n - 1) * TCC]$ where I is the interest rate, and n is the equipment life.

Oxidation Catalysts

The cost of adding an oxidation catalyst to a new or existing lean burn spark ignition (SI) engine was estimated based on information obtained from a manufacturer of oxidation catalysts for RICE¹. The vendor provided equipment cost estimates for six generic sized engines ranging from 500 to 8,000 horsepower (HP). The data obtained from the vendor were used to calculate capital and annual cost equations for oxidation catalyst control for RICE at major and area sources. Based on vendor information, EPA assumed there would be no difference between installing oxidation catalyst control on an existing source versus on a new source.

The equipment cost from the oxidation catalyst manufacturer and the OAQPS control cost methodology were used to calculate capital and annualized costs. The capital cost includes the direct, indirect, and contingency costs of installation of the oxidation catalyst. The total annual cost includes the direct and indirect annual costs of operating and maintaining the oxidation catalyst. Maintenance costs were estimated based on maintenance information for CDPF presented in Table 6.2-30 of the nonroad diesel engine regulatory impact analysis (RIA)². The nonroad diesel RIA did not provide any maintenance costs for oxidation catalysts. The EPA would expect that similar maintenance costs would be associated with CDPF and oxidation catalysts, and therefore felt it was appropriate to use the maintenance cost information from the nonroad diesel RIA. Table 6.2-30 of the nonroad diesel RIA indicated that a maintenance interval of 3,000 hours for engines below 175 HP and 4,500 hours for engines above 175 HP was appropriate. Table 6.2-30 estimates the cost for maintenance is \$65 for engines up to 600 HP and \$260 per event for engines above 600 HP. The EPA has used the assumption that SI engines operate 2,800 hours per year. To provide a conservative estimate of annual maintenance costs for an oxidation catalyst, it was assumed that maintenance is required for all oxidation catalysts every year and the cost for maintenance would be \$260. An equipment life of 20 years and an interest rate of 7 percent were used to estimate the indirect annual costs. The fuel penalty associated with operating an oxidation catalyst was assumed to be negligible.

A summary of the costs and linear regression statistical results is provided in Appendix A. The annualized cost equation for oxidation catalyst on lean burn SI engines was estimated at:

$$\text{Oxidation Catalyst Annual Cost} = 1.52 * \text{HP} + 393$$

where;

HP = engine size in HP.

The capital cost equation for installing an oxidation catalyst on a lean burn SI engine was calculated to be:

$$\text{Oxidation Catalyst Capital Cost} = 11.3 * \text{HP} - 170$$

where;

HP = engine size in HP.

The linear equations have a correlation coefficient of 0.9907, which shows the data fit the equations very closely. Therefore, the equations were used to estimate annualized and capital cost for oxidation catalysts for stationary RICE. A summary of the cost calculations, regression analyses, and graphical representations of the annual and capital cost data are presented in Appendix A.

Non-Selective Catalytic Reduction

Non-selective catalytic reduction, also referred to as a “three way catalyst,” is the only available control technology for rich burn RICE that can effectively reduce the emissions of HAP. This is because rich burn engines operate at stoichiometric air-to-fuel ratios and therefore do not have sufficient oxygen available for oxidation catalysts. The catalyst is formulated to enhance both reduction and oxidation reactions, which reduces the emissions of nitrogen oxides (NO_x), carbon monoxide (CO), and volatile organic compounds (VOC). Cost data were obtained from a manufacturer of NSCR^{3,4}. The cost data contained information for three Caterpillar engine models and five generic sized rich burn engines. Again, based on vendor information, EPA assumed there would be no difference between installing NSCR on an existing source versus a on new source.

The capital cost includes the direct, indirect, and contingency costs of installation of NSCR. The total annual cost includes the direct and indirect annual costs of operating and maintaining the catalyst. Maintenance costs were estimated using the maintenance cost information for CDPF presented in Table 6.2-30 of the nonroad diesel RIA, referenced earlier. The catalyst manufacturer that provided the NSCR cost information recommends a maintenance interval of 3,000 hours. The EPA would expect that similar maintenance costs would be associated with CDPF and NSCR, and therefore felt it was appropriate to use the maintenance cost information from the

nonroad diesel RIA. Table 6.2-30 of the nonroad diesel RIA estimates the cost for maintenance was \$65 for engines up to 600 HP and \$260 per event for engines above 600 HP. The EPA has used the assumption that SI engines operate 2,800 hours per year. To provide a conservative estimate of annual maintenance costs for the NSCR, it was assumed that maintenance is required every year at a cost of \$260. An equipment life of 20 years and an interest rate of 7 percent were used to estimate the indirect annual costs. The fuel penalty associated with operating the NSCR was assumed to be negligible.

A linear regression analysis was done on the data set for NSCR on rich burn engines and the linear equation for annualized cost was;

$$\text{NSCR Annual Cost} = 2.65 * \text{HP} + 657$$

where;

HP = engine size in HP.

The capital cost equation for installing a NSCR on a rich burn SI engine was calculated to be:

$$\text{NSCR Capital Cost} = 19.7 * \text{HP} + 1799$$

where;

HP = engine size in HP.

The linear equations have a correlation coefficient of 0.9887, which shows the equations are a good estimation of the cost data. Therefore, this equation was used to estimate annualized and capital cost for NSCR for stationary RICE. A summary of the costs, linear regression statistics, and a graph of the data are presented in Appendix A.

Catalyzed Diesel Particulate Filters

Catalyzed diesel particulate filters is a control technology that reduces the emissions of HAP from diesel CI engines. It is primarily installed on engines for the reduction of particulate matter (PM) from diesel exhaust. The catalyst element in the CDPF is also effective in reducing the emissions of CO, VOC, and HAP. Costs for CI engines will be calculated for existing and for new engines. This is because installation costs and compliance costs will be different for new and existing CI engines and therefore will be estimated separately in this analysis. Using equipment cost data and the OAQPS cost methodology, a cost equation was developed for prime and emergency CI RICE.

Existing CI Engines

Cost data for retrofitting CDPF on existing engines were obtained from the California ARB presentation entitled "Methods and Key Assumptions for Estimating the Costs for In-Use Stationary Engines⁵." The data set included annualized cost data for 11 engines. The cost data available for CDPF include a passive or active catalyst element. The passive CDPF use a catalyzed coating to reduce emissions of CO, VOC, and HAP emissions, and reduce the ignition temperature necessary for oxidation of PM. The active filters use heat from the engine or from a secondary source to regenerate the catalyst media.

A linear regression analysis was done on the data set and the linear equation for annualized cost was;

$$\text{CDPF Annual Cost} = 6.27 * \text{HP} + 1094$$

where;

HP = engine size in HP.

The capital cost equation for installing a CDPF on a CI engine was calculated to be:

$$\text{CDPF Capital Cost} = 7.48 * \text{HP} + 1304$$

where;

HP = engine size in HP.

The linear equations have a correlation coefficient of 0.8038, which shows the equation is a good approximation of the data. Therefore, this equation was used to estimate annualized cost and capital cost for retrofitting CDPF for stationary CI prime and emergency engines. A graphical representation of the cost data is shown in Appendix A.

New CI Engines

For the cost of installing CDPF on new engines, EPA used the cost information that was developed for the proposed NSPS for stationary CI engines⁶. These costs were presented in the memorandum entitled "Control Costs for NO_x Adsorbers and CDPF for CI engines," which can be found in the rulemaking docket for the CI NSPS (Docket ID Number EPA-HQ-OAR-2005-0029). The costs for CDPF in that memorandum were based on information obtained from the nonroad diesel RIA. For the stationary CI NSPS, EPA estimated that annualized costs for installing CDPF on new stationary CI engines varied from \$130 to \$3,100 depending on engine size. Based on these costs, EPA estimated the average annualized cost to be \$1/HP for both prime and emergency stationary CI engines. The average cost per HP was used to

estimate annualized cost for CDPF for new CI prime and emergency engines at major and area sources. The capital cost was estimated using the same data points and was calculated to be \$1.5/HP.

Summary

The following table presents a summary of the costs for control devices to reduce HAP emissions from engines located at area and major sources. The equations can be used to estimate regulatory costs for existing and new engines, as applicable.

Table 1. Summary of Control Costs for HAP Controls

Engine Type	HAP Control Device	Annualized Costs	Capital Costs
2SLB SI	Oxidation Catalyst	$1.52 * HP + 393$	$11.3 * HP - 170$
4SLB SI	Oxidation Catalyst	$1.52 * HP + 393$	$11.3 * HP - 170$
4SRB SI	NSCR	$2.65 * HP + 657$	$19.7 * HP + 1799$
CI – retrofit	CDPF	$6.27 * HP + 1094$	$7.48 * HP + 1304$
CI – new	CDPF	\$1/HP	\$1.5/HP

References

1. Email from Mike Leonard, Miratech to Brenda Riddle, Alpha-Gamma Technologies. July 20, 2005.
2. Final Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines. Assessment and Standards Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency. May 2004. EPA/420-04-007.
3. Email from Mike Leonard, Miratech to Brad Nelson, Alpha-Gamma Technologies. July 21, 2005.
4. Email from Nick Huff, Miratech to Jennifer Snyder, Alpha-Gamma Technologies. September 15, 2003.
5. Presentation by CARB for Public Consultation Meeting to Discuss Regulatory Approaches to Reduce Emissions from Stationary Diesel Fueled Engines. March 6, 2003. Presentation of the Methods and Key Assumptions for Estimating the Costs for In-Use Stationary Engines.
6. Memorandum from Tanya Parise, Alpha-Gamma Technologies Inc. to Sims Roy, U.S. Environmental Protection Agency, OAQPS ESD Combustion Group. May 31, 2005. Control Costs for NO_x adsorbers and CDPF for CI Engines.

Appendix A

Control Cost Summary and Linear Regression Statistics

Oxidation Catalyst Cost

Data obtained from Final Regulatory Analysis: Control of Emissions from Nonroad Diesel Engines.

Additional Data from Final Regulatory Support Document: Control of Emissions from Unregulated Nonroad Engines.

Engine Size (HP)	Equipment Cost	Direct Costs		Indirect Costs		Total Capital Cost	Regression Capital Cost	Direct Annual Cost	Indirect Annual Cost	Total Annual Cost	Regression Annual Cost	Annual Cost/Hp
		PEC	DIC	IIC	C							
500	\$5,390	\$6,360.20	\$1,908.06	\$1,780.86	\$190.81	\$10,240	5,503	\$260	\$1,532	\$1,792	1,156	\$3.58
1000	\$6,930	\$8,177.40	\$2,453.22	\$2,289.67	\$245.32	\$13,166	11,177	\$260	\$1,925	\$2,185	1,918	\$2.19
2000	\$11,180	\$13,192.40	\$3,957.72	\$3,693.87	\$395.77	\$21,240	22,524	\$260	\$3,010	\$3,270	3,443	\$1.64
3000	\$14,210	\$16,767.80	\$5,030.34	\$4,694.98	\$503.03	\$26,996	33,871	\$260	\$3,784	\$4,044	4,968	\$1.35
5000	\$28,480	\$33,606.40	\$10,081.92	\$9,409.79	\$1,008.19	\$54,106	56,565	\$260	\$7,428	\$7,688	8,018	\$1.54
8000	\$49,740	\$58,693.20	\$17,607.96	\$16,434.10	\$1,760.80	\$94,496	90,605	\$260	\$12,856	\$13,116	12,593	\$1.64

Assumptions:

PEC = 118% of purchased equipment cost (PEC).

DIC = 30% of purchased equipment cost (PEC).

IIC = 28% of purchased equipment cost (PEC).

C = 3% of purchased equipment cost (PEC).

Direct Annual Cost = (\$5 x Hp) + (14.26 x 5).

Indirect Annual Cost = 60% of direct annual cost + 4% of total capital cost + capital recovery.

Capital Recovery assumes equipment 0.09439293

SUMMARY OUTPUT - Annual Cost

Regression Statistics

Multiple R	0.99073446
R Square	0.98155477
Adjusted R Square	0.97694346
Standard Error	660.027964
Observations	6

ANOVA

	df	SS	MS	F	Significance F
Regression	1	92728904.4	92728904.4	212.858235	0.00012838
Residual	4	1742547.65	435636.913		
Total	5	94471452.1			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	393.098586	433.592132	0.90660913	0.41588915	-810.74866	1596.94583
Engine Size	1.52495566	0.10452303	14.5896619	0.00012838	1.23475261	1.81515871

SUMMARY OUTPUT - Capital Cost

Regression Statistics

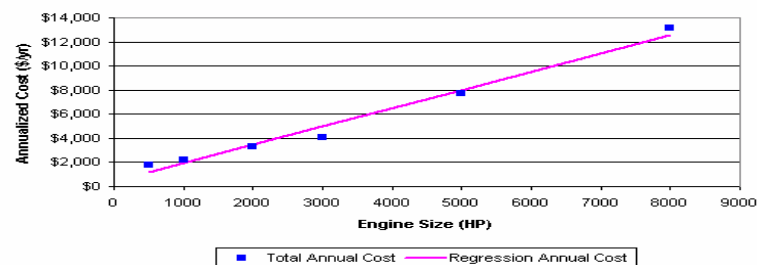
Multiple R	0.99073446
R Square	0.98155477
Adjusted R Square	0.97694346
Standard Error	4911.17814
Observations	6

ANOVA

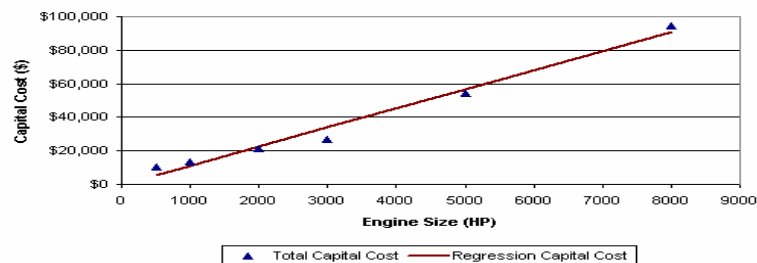
	df	SS	MS	F	Significance F
Regression	1	5134070542	5134070542	212.858235	0.00012838
Residual	4	96478683	24119670.8		
Total	5	5230549225			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	-170.4063	3226.29997	-0.0528179	0.9604096	-9128.0696	8787.25702
Engine Size	11.3469873	0.77774162	14.5896619	0.00012838	9.18762589	13.5063487

Oxidation Catalyst Annual Cost



Oxidation Catalyst Capital Cost



Three Way Catalyst Cost

Generic rich-burn three-way catalyst data from Miratech 7/21/2005.

Additional Data from Miratech in response to 9/15/2003 letter from Jennifer Snyder

Model Engine	Size (HP)	Equipment Cost	Direct Costs		Indirect Costs		Total Capital Cost	Regression Capital Cost	Direct Annual Cost	Indirect Annual Cost	Total Annual Cost	Regression Annual Cost	Annual Cost/Hp
			PEC	DIC	IIC	C							
CATERPILLAR G3306	167	\$1,980	\$2,336.40	\$700.92	\$654.19	\$70.09	\$3,762	\$5,096	\$260	\$662	\$922	1,101	\$5.52
CATERPILLAR G3408	255	\$4,660	\$5,498.80	\$1,649.64	\$1,539.66	\$164.96	\$8,853	\$6,833	\$260	\$1,346	\$1,606	1,334	\$6.30
CATERPILLAR G3408	300	\$4,620	\$5,451.60	\$1,635.48	\$1,526.45	\$163.55	\$8,777	\$7,721	\$260	\$1,336	\$1,596	1,454	\$5.32
Generic Rich-Burn Engine	300	\$5,180	\$6,112.40	\$1,833.72	\$1,711.47	\$183.37	\$9,841	\$7,721	\$260	\$1,479	\$1,739	1,454	\$5.80
Generic Rich-Burn Engine	500	\$6,610	\$7,799.80	\$2,339.94	\$2,183.94	\$233.99	\$12,558	\$11,669	\$260	\$1,844	\$2,104	1,984	\$4.21
Generic Rich-Burn Engine	800	\$8,410	\$9,923.80	\$2,977.14	\$2,778.66	\$297.71	\$15,977	\$17,591	\$260	\$2,303	\$2,563	2,780	\$3.20
Generic Rich-Burn Engine	1500	\$13,370	\$15,776.60	\$4,732.98	\$4,417.45	\$473.30	\$25,400	\$31,409	\$260	\$3,570	\$3,830	4,637	\$2.55
Generic Rich-Burn Engine	3000	\$33,630	\$39,683.40	\$11,905.02	\$11,111.35	\$1,190.50	\$63,890	\$61,019	\$260	\$8,742	\$9,002	8,617	\$3.00

Assumptions:

PEC = 118% of purchased equipment cost (PEC).

DIC = 30% of purchased equipment cost (PEC).

IIC = 28% of purchased equipment cost (PEC).

C = 3% of purchased equipment cost (PEC).

Direct Annual Cost = (\$5 x Hp) + (14.26 x 5).

Indirect Annual Cost = 60% of direct annual cost + 4% of total capital cost + capital recovery.

Capital Recovery assumes equipment life of 20 years and 7% 0.09439293

SUMMARY OUTPUT - Annual Cost

Regression Statistics

Multiple R	0.98867533
R Square	0.9774789
Adjusted R Square	0.97372539
Standard Error	422.191634
Observations	8

ANOVA

	df	SS	MS	F	Significance F
Regression	1	46418204.4	46418204.4	260.416855	3.6002E-06
Residual	6	1069474.66	178245.776		
Total	7	47487679			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	657.783688	204.776055	3.21220998	0.01831596	156.714366	1158.85301
Size (HP)	2.65290585	0.1643945	16.1374364	3.6002E-06	2.25064669	3.055165

SUMMARY OUTPUT - Capital Cost

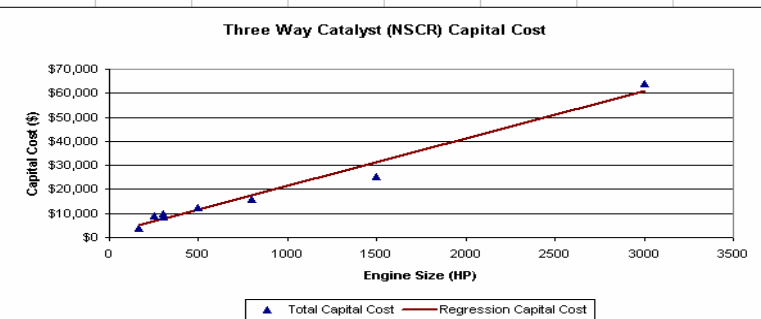
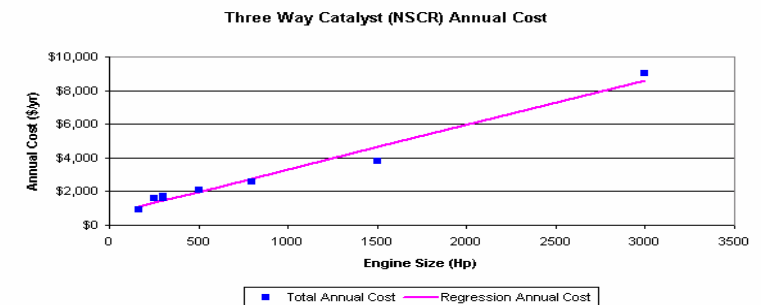
Regression Statistics

Multiple R	0.98867533
R Square	0.9774789
Adjusted R Square	0.97372539
Standard Error	3141.47042
Observations	8

ANOVA

	df	SS	MS	F	Significance F
Regression	1	2570011337	2570011337	260.416855	3.6002E-06
Residual	6	59213018.5	9868836.41		
Total	7	2629224355			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	1799.07948	1523.71072	1.18072246	0.28239336	-1929.3091	5527.46802
Size (HP)	19.7399109	1.2232371	16.1374364	3.6002E-06	16.7467554	22.730664



Catalyzed Diesel Particulate Filter Cost Data Analysis - Retrofit

Cost data for retrofitting CDPF were obtained from the California ARB presentation entitled "Methods and Key Assumptions for Estimating the Costs for In-Use Stationary Engines."

Model Engine	Engine Size (Hp)	DPF Total Annualized Costs	Annual Cost (\$/HP)	Regression Annual Cost	Calculated Capital Cost	Capital Cost (\$/HP)	Regression Capital Cost
Caterpillar 3516B	2848	14,609	5.1	18,959	17,413	6.1	22,599
Caterpillar	2680	25,882	9.7	17,905	30,851	11.5	21,343
Caterpillar 3516B	2680	20,863	7.8	17,905	24,869	9.3	21,343
Cummins KTTA50-G2	2220	6,370	2.9	15,020	7,593	3.4	17,903
Caterpillar 3412 DISTA	1100	4,311	3.9	7,994	5,138	4.7	9,529
Caterpillar	1072	14,240	13.3	7,819	16,974	15.8	9,320
Caterpillar 3412C	896	5,463	6.1	6,715	6,512	7.3	8,004
Caterpillar	536	5,696	10.6	4,456	6,790	12.7	5,312
Caterpillar 3406	519	4,392	8.5	4,350	5,235	10.1	5,185
Caterpillar 3406	449	3,957	8.8	3,911	4,717	10.5	4,662
Caterpillar	175	1,443	8.2	2,192	1,720	9.8	2,613
Average			7.7			9.2	

SUMMARY OUTPUT - Annual Cost

Regression Statistics

Multiple R	0.803791559
R Square	0.646080871
Adjusted R Square	0.606756523
Standard Error	4995.552821
Observations	11

ANOVA

	df	SS	MS	F	Significance F
Regression	1	410008127.6	410008127.6	16.42953815	0.00287051
Residual	9	224599931.9	24955547.99		
Total	10	634608059.5			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	1094.360085	2612.738025	0.418855651	0.685140777	-4816.06846	7004.788627
X Variable 1	6.272637475	1.54752442	4.053336668	0.00287051	2.771891357	9.773383594

SUMMARY OUTPUT - Capital Cost

Regression Statistics

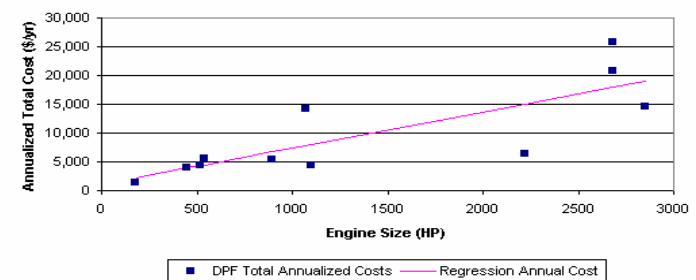
Multiple R	0.803791559
R Square	0.646080871
Adjusted R Square	0.606756523
Standard Error	5954.698962
Observations	11

ANOVA

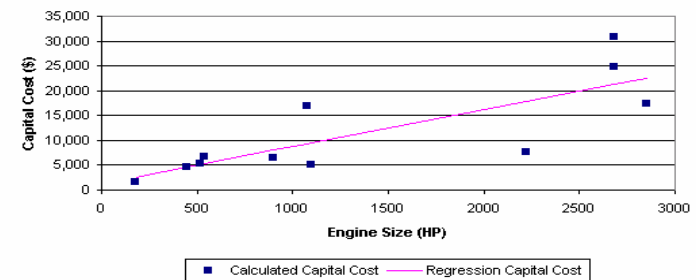
	df	SS	MS	F	Significance F
Regression	1	582565788.2	582565788.2	16.42953815	0.00287051
Residual	9	319125957.6	35458439.73		
Total	10	901691745.8			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	1304.477222	3114.383725	0.418855651	0.685140777	-5740.7536	8349.708044
Engine Size (Hp)	7.47698387	1.844649108	4.053336668	0.00287051	3.304094497	11.64987324

Catalyzed Diesel Particulate Filter Annual Cost Existing Engines



Catalyzed Diesel Particulate Filter Capital Cost Existing Engines



MEMORANDUM

DATE: June 29, 2010

SUBJECT: Control Costs for Existing Stationary SI RICE

FROM: Bradley Nelson, EC/R, Inc.

TO: Melanie King, EPA OAQPS/SPPD/ESG

1.0 PURPOSE

The purpose of this memorandum is to present information on the costs of control technology options for reducing hazardous air pollutants (HAP) emissions from existing stationary spark ignition (SI) reciprocating internal combustion engines (RICE). The memorandum will look at the cost of retrofitting control technology on existing engines. This information will be used to determine national impacts associated with the final rule.

2.0 INTRODUCTION

EPA has determined that oxidation catalysts for two-stroke lean burn (2SLB) and four-stroke lean burn (4SLB) engines, and non-selective catalytic reduction (NSCR) for four-stroke rich burn (4SRB) engines are applicable controls for HAP reduction from existing stationary SI RICE. To determine the capital and annual costs for these control technologies, equipment cost information was obtained from industry groups¹ and vendors and manufacturers of SI engine control technology. In some cases, the industry groups provided a breakdown of the capital and annual cost components for each of the retrofit options. Using this cost data, annualized cost and capital cost equations for oxidation catalysts and NSCR were developed.

¹ Reciprocating Internal Combustion Engine National Emission Standards for Hazardous Air Pollutants (RICE NESHAP) Proposed Revisions – Emission Control Costs Analysis Background for “Above the Floor” Emission Controls for Natural Gas-Fired RICE, Innovative Environmental Solutions Inc., October 2009. (EPA-HQ-OAR-2008-0708-0279) .

3.0 CONTROL COST METHODOLOGY

The following sections describe the methodology used to derive the total capital and total annual costs for each of the control technology options. These methodologies were used to calculate total capital and total annual costs when only purchased equipment costs were available (e.g., vendor equipment costs). The methodologies were not used for cost data provided by industry groups because they included a breakdown of the actual total capital and total annual costs. A summary of the methodologies, equations, and assumptions used to estimate the total capital and total annual costs for some of the costs data are described in the following sections.

3.1 *Total Capital Costs*

The total capital cost includes the direct and indirect costs of purchasing and installing the control equipment. The direct cost includes the cost of purchasing the equipment and instrumentation, cost of shipping, and the cost of installing the control equipment. The indirect cost includes the costs for engineering, contractor fees, testing costs, and also includes costs for contingencies, such as additional modifications, or delays in startup. The total capital cost equation can be summarized as follows:

$$\text{Total Capital Cost (TCC)} = \text{Direct Costs (DC)} + \text{Indirect Costs (IC)}$$

The direct costs include the costs of purchasing and installing the control equipment and can be summarized using the following equation;

$$\text{DC} = \text{Purchased Equipment Cost (PEC)} + \text{Direct Installation Costs (DIC)}.$$

A summary of the cost assumptions for PEC includes the following:

- Control Device and Auxiliary Equipment (EC);
- Instrumentation (10% of EC);
- Sales Tax (3% of EC);
- Freight (5% of EC);

and can be summarized as:

$$\text{PEC} = 118\% \text{ EC}.$$

A summary of the cost assumptions for DIC includes the following:

- Foundations and Supports (8% of PEC);
- Handling and Erection (14% of PEC);
- Electrical (4% of PEC);
- Piping (2% of PEC);
- Insulation for Ductwork (1% of PEC);

- Painting (1% of PEC);

and can be summarized as:

$$DIC = 30\% \text{ PEC} = 0.3 \text{ PEC}.$$

Therefore, the direct costs can be simplified using the following equation:

$$DC = \text{PEC} + 0.3 \text{ PEC} = 1.3 \text{ PEC}.$$

The indirect costs include the costs of engineering and contractor fees and contingencies and can be summarized using the following equation:

$$IC = \text{Indirect Installation Costs (ICC)} + \text{Contingencies (C)}.$$

A summary of the cost assumptions for ICC includes the following:

- Engineering (10% of PEC);
- Construction and Field Expenses (5% of PEC);
- Contractor Fees (10% of PEC);
- Startup (2% of PEC);
- Performance Test (1% of PEC);

and can be summarized as:

$$IIC = 28\% \text{ PEC} = 0.28 \text{ PEC}.$$

A summary of the cost assumptions for C includes the following:

- Equipment Redesign and Modifications;
- Cost Escalations;
- Delays in Startup;

and is assumed to be:

$$C = 3\% \text{ PEC} = 0.03 \text{ PEC}.$$

Therefore, the IC can be summarized using the following equation:

$$IC = 0.28 \text{ PEC} + 0.03 \text{ PEC} = 0.31 \text{ PEC},$$

and the simplified TCC equation can be expressed as:

$$\text{TCC} = 1.3 \text{ PEC} + 0.31 \text{ PEC} = 1.61 \text{ PEC} = 1.61 (1.18 \text{ EC}) = 1.9 \text{ EC}$$

3.2 *Total Annual Costs*

The total annual cost includes the direct and indirect annual costs of operating and maintaining the control equipment. The direct annual cost includes the cost of the utilities, operating labor, and control device cleaning and maintenance. The indirect annual cost includes the overhead costs such as spare parts for the control equipment, administrative charges, and the capital recovery of the control technology. The total annual cost equation can be summarized as follows:

Total Annual Cost (TAC) = Direct Annual Costs (DAC) + Indirect Annual Costs (IAC).

The DAC includes the following parameters:

- Utilities;
- Operating Labor;
- Maintenance;
- Annual Compliance Test;
- Catalyst Cleaning;
- Catalyst Replacement;
- Catalyst Disposal.

The IAC includes the following parameters:

- Overhead;
- Fuel Penalty;
- Property Tax;
- Insurance;
- Administrative Charges;
- Capital Recovery = $\{I(1+I)^n / ((1+I)^n - 1) * TCC\}$ where I is the interest rate, and n is the equipment life.

To calculate DAC, the costs were broken up into three separate costs: operation and maintenance materials cost, operation and maintenance labor cost, and the cost for annual performance testing or downtime or allowance for catalyst washing. Actual annual cost data from the industry groups were used to estimate the DAC for each of the control technologies. The IAC was broken up into three separate costs: administrative, fuel penalty, and capital recovery. Again, cost data from the industry groups was used to estimate these costs for each of the control technologies. No fuel penalty was estimated for the oxidation catalyst control technologies, because this control technology does not increase the fuel usage of the SI engine.

4.0 CONTROL COST EQUATIONS

Control cost equations were developed for 2SLB oxidation catalyst, 4SLB oxidation catalyst, and a NSCR for 4SRB engines using the total capital cost and total annual cost data for each control technology. Control cost equations for 2SLB and 4SLB oxidation catalysts were developed separately because the 2SLB oxidation catalyst requires a premium catalyst to reduce the HAP compounds because of the low exhaust temperature of 2SLB engines.

4.1 *2SLB Oxidation Catalyst*

The 2SLB oxidation catalyst is an effective control technology that reduces HAP emissions from a 2SLB SI engine by oxidizing organic compounds using a catalyst. The oxidation catalyst unit contains a honeycomb-like structure or substrate with a large surface area that is coated with a premium active catalyst layer, such as, platinum or palladium. The oxidation catalyst works by oxidizing carbon monoxide (CO) and gaseous hydrocarbons (HAP) in the exhaust gas to carbon dioxide (CO₂) and water. The reduction of CO and HAP varies depending on the type of catalyst used and the exhaust temperature of the pollutant stream.

The cost of retrofitting an oxidation catalyst to an existing 2SLB engine was estimated using cost data obtained from vendors and industry groups covering engines ranging from 58 horsepower (HP) to 4,670 HP. An equipment life of 10 years and an interest rate of 7 percent were used to estimate the capital recovery of the control technology and the fuel penalty was assumed to be negligible. The cost equations are presented in 2009 dollars.

The total annualized cost equation for retrofitting an oxidation catalyst on a 2SLB engine was estimated to be:

$$\text{2SLB Oxidation Catalyst Total Annual Cost} = \$11.4 \times \text{HP} + \$13,928$$

where;

HP = engine size in HP.

The linear equation has a correlation coefficient of 0.8046, which shows the data fits the equation closely. Therefore, this equation was used to estimate annualized cost for an oxidation catalyst on a 2SLB engine.

The total capital cost equation for retrofitting an oxidation catalyst on a 2SLB engine was estimated to be:

$$\text{2SLB Oxidation Catalyst Total Capital Cost} = \$47.1 \times \text{HP} + \$41,603$$

where;

HP = engine size in HP.

A summary of the cost calculations, regression analyses, and graphical representations of the annual and capital cost data are presented in Appendix A.

4.2 4SLB Oxidation Catalyst

The 4SLB oxidation catalyst is an effective control technology that reduces HAP emissions from a 4SLB SI engine by oxidizing organic compounds using a catalyst. The oxidation catalyst unit contains a honeycomb-like structure or substrate with a large surface area that is coated with a premium active catalyst layer, such as, platinum or palladium. The oxidation catalyst works by oxidizing CO and gaseous hydrocarbons (HAP) in the exhaust gas to CO₂ and water. The reductions of CO and HAP vary depending on the type of catalyst used and the exhaust temperature of the pollutant stream.

The cost of retrofitting an oxidation catalyst to an existing 4SLB engine was estimated using cost data obtained from vendors and industry groups covering engines ranging from 400 HP to 8,000 HP. Again, an equipment life of 10 years and an interest rate of 7 percent were used to estimate the capital recovery of the control technology and the fuel penalty was assumed to be negligible. The cost equations are presented in 2009 dollars.

The total annualized cost equation for retrofitting an oxidation catalyst on a 4SLB engine was estimated to be:

$$\text{4SLB Oxidation Catalyst Total Annual Cost} = \$1.81 \times \text{HP} + \$3,442$$

where;

HP = engine size in HP.

The linear equation has a correlation coefficient of 0.9779, which shows the data fits the equation very closely. Therefore, this equation was used to estimate annualized cost for an oxidation catalyst on a 4SLB engine.

The total capital cost equation for retrofitting an oxidation catalyst on a 4SLB SI engine was estimated to be:

$$\text{4SLB Oxidation Catalyst Total Capital Cost} = \$12.8 \times \text{HP} + \$3,069$$

where;

HP = engine size in HP.

A summary of the cost calculations, regression analyses, and graphical representations of the annual and capital cost data are presented in Appendix A.

4.3 *Non-Selective Catalytic Reduction*

The NSCR or three-way catalyst is used to control HAP emissions from 4SRB engines. In addition to HAP reductions, NSCR also reduces the emissions of nitrogen oxides (NO_x), CO, and other hydrocarbons (HC). The reduction of HAP and CO takes place through an oxidation reaction that converts HAP to CO₂ and water and converts CO to CO₂. The conversion of NO_x takes place through a reduction of the NO_x to nitrogen gas and oxygen.

The cost of retrofitting an NSCR on an existing 4SRB engine was estimated based on cost data received from vendors and industry groups. A linear regression analysis was done on the data set and the linear equation for annualized cost was;

$$\text{NSCR Annual Cost} = \$4.77 \times \text{HP} + \$5,679$$

where;

HP = engine size in HP.

The linear equation has a correlation coefficient of 0.7987, which shows an acceptable representation of the cost data. Therefore, this equation was used to estimate annualized cost for retrofitting the NSCR control technology on 4SRB engines.

The capital cost equation for retrofitting an air-to-fuel ratio (AFR) controller and NSCR on a 4SRB engine was estimated to be:

$$\text{NSCR Capital Cost} = \$24.9 \times \text{HP} + \$13,118$$

where;

HP = engine size in HP.

A summary of the cost calculations, regression analyses, and graphical representations of the annual and capital cost data are presented in Appendix A.

5.0 SUMMARY

The following table presents a summary of the annual and capital control costs as a function of engine size for the control technologies applicable to existing stationary SI engines, as discussed in this memorandum.

**Table 1. Summary of Annual and Capital Costs Equations
for Existing Stationary SI Engines**

HAP Control Device	Annual Cost (\$2009)	Capital Cost (\$2009)
2SLB Oxidation Catalyst	$\$11.4 \times \text{HP} + \$13,928$	$\$47.1 \times \text{HP} + \$41,603$
4SLB Oxidation Catalyst	$\$1.81 \times \text{HP} + \$3,442$	$\$12.8 \times \text{HP} + \$3,069$
NSCR	$\$4.77 \times \text{HP} + \$5,679$	$\$24.9 \times \text{HP} + \$13,118$

6.0 References

Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment N (EPA-HQ-OAR-2008-0708-0279).

Email from Bruce Chrisman, Cameron's Compression Systems to Tanya Parise, EC/R, Subject: Existing RICE NESHAP - Information for EPA for 2SLB Engines, October 16, 2009.

Email from James Harrison, Exterran to Melanie King, EPA, Subject: 2SLB - Cameron oxidation catalyst pricing, October 20, 2009.

Anadarko Petroleum Corporation Comments on the Proposed Revisions to the National Emission Standard for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, June 2, 2009, Case Study (EPA-HQ-OAR-2008-0708-0186).

Email from Mike Leonard, Miratech Corporation to Brenda Riddle, AGTI, RE: Clarification of SCR Cost Information for EPA, July 20, 2005. (EPA-HQ-OAR-2005-0030-0086).

Email from Antonio Santos, MECA to Tanya Parise, EC/R, Subject: EPA Proposed Existing RICE NESHAP - Cost of Aftertreatment, October 2, 2009. Response #2.

Price quote from Charles Ball, Emissions & Silencer Technology for an oxidation catalyst for a 500 HP 4SLB engine.

Memorandum from Tom McGrath, IES to Brad Nelson, EC/R, Request for Additional Cost Detail for Gas-Fired Engines Emission Controls, April 19, 2010.

Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment D (EPA-HQ-OAR-2008-0708-0279).

Email from Nick Huff, Miratech to Jennifer Synder, AGTI, SCR Questions for RICE MACT, October 23, 2003 (EPA-HQ-OAR-2005-0029-0038).

Email from Mike Leonard, Miratech to Brad Nelson, AGTI, Information Request, July 21, 2005 (EPA-HQ-OAR-2005-0030-0087).

Four Corners Air Quality Task Force Report of Mitigation Options, November 1, 2007.
Mitigation Option: Use of NSCR/3-Way Catalysts and Air/Fuel Ratio Controllers on Rich Burn Stoichiometric Engines (EPA-HQ-OAR-2008-0708-0009).

Appendix A

Control Cost Summary and Linear Regression Statistics

2SLB Oxidation Catalyst Cost (\$2009)

Engine Size (HP)	Equipment Cost	Direct Costs		Indirect Costs		Total Capital Cost	Direct Annual Costs			Indirect Annual Costs			Total Annual Cost	Data Source
		PEC	DIC	IIC	C		O&M Materials	O&M Labor	Total Direct Annual Cost (TDAC)	Administrative Charges (ADMC)	Fuel Penalty (FPC)	Capital Recovery (CRC)	Total Indirect Annual Cost (TIAC)	
296	\$24,987	\$29,485	\$8,845	\$8,256	\$885	\$47,470	\$7,958	\$875	\$8,833	\$225	\$0	\$6,759	\$6,984	\$15,817 Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment N (EPA-HQ-OAR-2008-0708-0279)
192	\$24,987	\$29,485	\$8,845	\$8,256	\$885	\$47,470	\$7,958	\$875	\$8,833	\$225	\$0	\$6,759	\$6,759	\$15,592 Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment N (EPA-HQ-OAR-2008-0708-0279)
384	\$30,409	\$35,883	\$10,765	\$10,047	\$1,076	\$57,771	\$7,958	\$875	\$8,833	\$225	\$0	\$8,225	\$8,225	\$17,058 Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment N (EPA-HQ-OAR-2008-0708-0279)
800	\$50,901	\$60,063	\$18,019	\$16,818	\$1,802	\$96,702	\$7,958	\$875	\$8,833	\$225	\$0	\$13,768	\$13,768	\$22,601 Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment N (EPA-HQ-OAR-2008-0708-0279)
58	\$12,191	\$14,385	\$4,316	\$4,028	\$432	\$23,160	\$7,958	\$875	\$8,833	\$225	\$0	\$3,298	\$3,298	\$12,131 Email from Bruce Chrisman, Cameron's Compression Systems to Tanya Parise, EC/R, Subject: Existing RICE NESHAP - Information for EPA for 2SLB Engines, October 16, 2009
600	\$51,378	\$60,626	\$18,188	\$16,975	\$1,819	\$97,608	\$7,958	\$875	\$8,833	\$225	\$0	\$13,897	\$14,122	\$22,955 Email from Bruce Chrisman, Cameron's Compression Systems to Tanya Parise, EC/R, Subject: Existing RICE NESHAP - Information for EPA for 2SLB Engines, October 16, 2009
148	\$14,589	\$17,215	\$5,165	\$4,820	\$516	\$27,716	\$7,958	\$875	\$8,833	\$225	\$0	\$3,946	\$4,171	\$13,004 Email from James Harrison, Exterran to Melanie King, EPA, Subject: 2SLB - Cameron oxidation catalyst pricing, October 20, 2009
296	\$22,123	\$26,105	\$7,832	\$7,309	\$783	\$42,029	\$7,958	\$875	\$8,833	\$225	\$0	\$5,984	\$6,209	\$15,042 Email from James Harrison, Exterran to Melanie King, EPA, Subject: 2SLB - Cameron oxidation catalyst pricing, October 20, 2009
192	\$14,589	\$17,215	\$5,165	\$4,820	\$516	\$27,716	\$7,958	\$875	\$8,833	\$225	\$0	\$3,946	\$4,171	\$13,004 Email from James Harrison, Exterran to Melanie King, EPA, Subject: 2SLB - Cameron oxidation catalyst pricing, October 20, 2009
384	\$22,123	\$26,105	\$7,832	\$7,309	\$783	\$42,029	\$7,958	\$875	\$8,833	\$225	\$0	\$5,984	\$6,209	\$15,042 Email from James Harrison, Exterran to Melanie King, EPA, Subject: 2SLB - Cameron oxidation catalyst pricing, October 20, 2009
600	\$30,409	\$35,883	\$10,765	\$10,047	\$1,076	\$57,771	\$7,958	\$875	\$8,833	\$225	\$0	\$8,225	\$8,450	\$17,283 Email from James Harrison, Exterran to Melanie King, EPA, Subject: 2SLB - Cameron oxidation catalyst pricing, October 20, 2009
800	\$37,871	\$44,688	\$13,406	\$12,513	\$1,341	\$71,947	\$7,958	\$875	\$8,833	\$225	\$0	\$10,244	\$10,469	\$19,302 Email from James Harrison, Exterran to Melanie King, EPA, Subject: 2SLB - Cameron oxidation catalyst pricing, October 20, 2009
3850						\$210,000			\$25,000	\$225	\$0	\$29,899	\$30,124	\$55,124 Anadarko Petroleum Corporation Comments on the Proposed Revisions to the National Emission Standard for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, June 2, 2009, Case Study (EPA-HQ-OAR-2008-0708-0186). Cost is for installation on a Clark TLAD-8 2SLB gas compressor engine.
4670						\$210,000			\$25,000	\$225	\$0	\$29,899	\$30,124	\$55,124 Anadarko Petroleum Corporation Comments on the Proposed Revisions to the National Emission Standard for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, June 2, 2009, Case Study (EPA-HQ-OAR-2008-0708-0186). Cost is for installation on a Cooper Bessemer 2SLB gas compressor engine.
2166						\$210,000			\$25,000	\$225	\$0	\$29,899	\$30,124	\$55,124 Anadarko Petroleum Corporation Comments on the Proposed Revisions to the National Emission Standard for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, June 2, 2009, Case Study (EPA-HQ-OAR-2008-0708-0186). Cost is for installation on a MEP 2SLB gas compressor engine.
1859						\$210,000			\$25,000	\$225	\$0	\$29,899	\$30,124	\$55,124 Anadarko Petroleum Corporation Comments on the Proposed Revisions to the National Emission Standard for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, June 2, 2009, Case Study (EPA-HQ-OAR-2008-0708-0186). Cost is for installation on a MEP 2SLB gas compressor engine.

Assumptions:

PEC = 118% of purchased equipment cost (PEC).

DIC = 30% of purchased equipment cost (PEC).

IIC = 28% of purchased equipment cost (PEC).

C = 3% of purchased equipment cost (PEC).

Capital Recovery assumes equipment life of 10 years and 7% interest rate.

0.142377503

O&M Materials cost covers the annualized equipment cost to replace the catalyst (every 3 years), thermocouples (every 7.5 years), crankcase filters (3 months), and annual catalyst rotation for cleaning. [Source: Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment N (EPA-HQ-OAR-2008-0708-0279)]

O&M Labor cost covers the annualized labor cost to replace and rotate (for cleaning) catalyst, thermocouples, and crankcase filter. [Source: Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment N (EPA-HQ-OAR-2008-0708-0279)]

2SLB Oxidation Catalyst Cost (\$2009)

SUMMARY OUTPUT - Capital Cost

Regression Statistics

Multiple R	0.887931512
R Square	0.788422369
Adjusted R Square	0.773309682
Standard Error	34869.66159
Observations	16

ANOVA

	df	SS	MS	F	Significance F
Regression	1	63432625775	63432625775	52.16956604	4.40556E-06
Residual	14	17022506190	1215893299		
Total	15	80455131965			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	41602.60574	11206.04006	3.712516244	0.002319141	17568.04028	65637.1712
X Variable 1	47.0511302	6.514205394	7.222850271	4.40556E-06	33.07954923	61.02271117

SUMMARY OUTPUT - Annual Cost

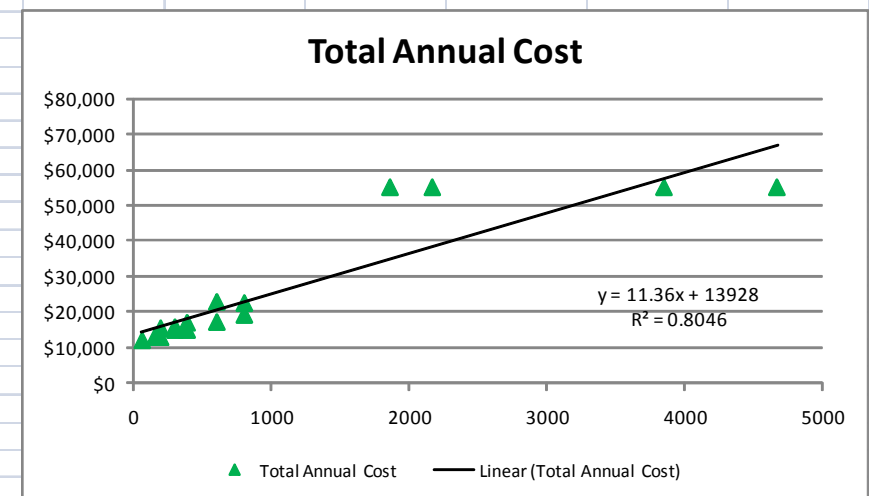
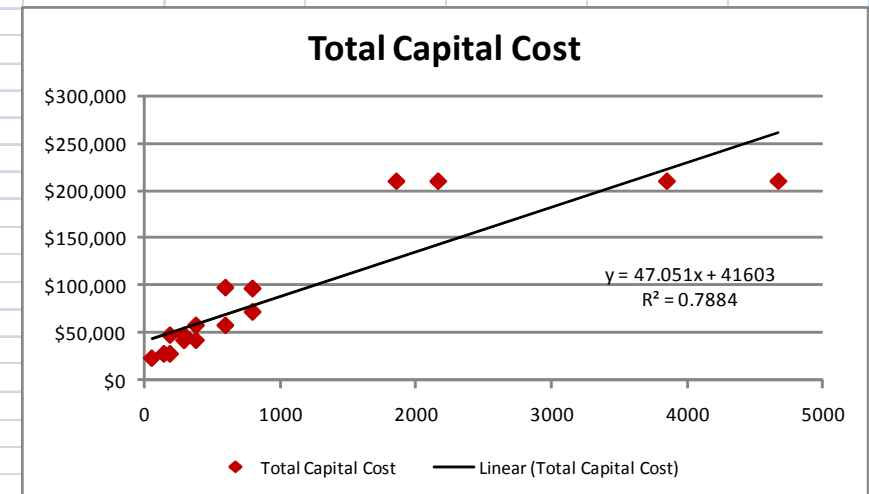
Regression Statistics

Multiple R	0.896978958
R Square	0.804571251
Adjusted R Square	0.790612055
Standard Error	8009.912446
Observations	16

ANOVA

	df	SS	MS	F	Significance F
Regression	1	3697938056	3697938056	57.63736182	2.5054E-06
Residual	14	898221763.5	64158697.39		
Total	15	4596159819			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	13928.11988	2574.140259	5.410785147	9.1811E-05	8407.138137	19449.10162
X Variable 1	11.3603976	1.496378585	7.591927411	2.5054E-06	8.150984738	14.56981046



4SLB Oxidation Catalyst Cost (\$2009)															
Engine Size (HP)	Equipment Cost	Direct Costs		Indirect Costs		Total Capital Cost	Direct Annual Costs			Indirect Annual Costs				Total Annual Cost	Data Source
		PEC	DIC	IIC	C		O&M Materials	O&M Labor	Total Direct Annual Cost (TDAC)	Administrative Charges (ADMC)	Fuel Penalty (FPC)	Capital Recovery (CRC)	Total Indirect Annual Cost (TIAC)		
500	\$6,361	\$7,505	\$2,252	\$2,102	\$225	\$12,084	\$1,891	\$1,053	\$2,944	\$225	\$0	\$1,720	\$1,945	\$4,889	Email from Mike Leonard, Miratech Corporation to Brenda Riddle, AGTI, RE: Clarification of SCR Cost Information for EPA, July 20, 2005. (EPA-HQ-OAR-2005-0030-0086). Costs converted from \$2005 to \$2009 using the Marshall and Swift Equipment Cost Index.
1000	\$8,178	\$9,650	\$2,895	\$2,702	\$289	\$15,536	\$1,891	\$1,053	\$2,944	\$225	\$0	\$2,212	\$2,212	\$5,156	Email from Mike Leonard, Miratech Corporation to Brenda Riddle, AGTI, RE: Clarification of SCR Cost Information for EPA, July 20, 2005. (EPA-HQ-OAR-2005-0030-0086). Costs converted from \$2005 to \$2009 using the Marshall and Swift Equipment Cost Index.
2000	\$13,193	\$15,568	\$4,670	\$4,359	\$467	\$25,064	\$1,891	\$1,053	\$2,944	\$225	\$0	\$3,569	\$3,569	\$6,513	Email from Mike Leonard, Miratech Corporation to Brenda Riddle, AGTI, RE: Clarification of SCR Cost Information for EPA, July 20, 2005. (EPA-HQ-OAR-2005-0030-0086). Costs converted from \$2005 to \$2009 using the Marshall and Swift Equipment Cost Index.
3000	\$16,769	\$19,787	\$5,936	\$5,540	\$594	\$31,857	\$1,891	\$1,053	\$2,944	\$225	\$0	\$4,536	\$4,536	\$7,480	Email from Mike Leonard, Miratech Corporation to Brenda Riddle, AGTI, RE: Clarification of SCR Cost Information for EPA, July 20, 2005. (EPA-HQ-OAR-2005-0030-0086). Costs converted from \$2005 to \$2009 using the Marshall and Swift Equipment Cost Index.
5000	\$33,608	\$39,658	\$11,897	\$11,104	\$1,190	\$63,849	\$1,891	\$1,053	\$2,944	\$225	\$0	\$9,091	\$9,091	\$12,035	Email from Mike Leonard, Miratech Corporation to Brenda Riddle, AGTI, RE: Clarification of SCR Cost Information for EPA, July 20, 2005. (EPA-HQ-OAR-2005-0030-0086). Costs converted from \$2005 to \$2009 using the Marshall and Swift Equipment Cost Index.
8000	\$58,697	\$69,262	\$20,779	\$19,393	\$2,078	\$111,512	\$1,891	\$1,053	\$2,944	\$225	\$0	\$15,877	\$15,877	\$18,821	Email from Mike Leonard, Miratech Corporation to Brenda Riddle, AGTI, RE: Clarification of SCR Cost Information for EPA, July 20, 2005. (EPA-HQ-OAR-2005-0030-0086). Costs converted from \$2005 to \$2009 using the Marshall and Swift Equipment Cost Index.
1000	\$8,500	\$10,030	\$3,009	\$2,808	\$301	\$16,148	\$1,891	\$1,053	\$2,944	\$225	\$0	\$2,299	\$2,524	\$5,468	Email from Antonio Santos, MECA to Tanya Parise, EC/R, Subject: EPA Proposed Existing RICE NESHAP - Cost of Aftertreatment, October 2, 2009. Response #2
500	\$3,700	\$4,366	\$1,310	\$1,222	\$131	\$7,029	\$1,891	\$1,053	\$2,944	\$225	\$0	\$1,001	\$1,001	\$3,945	Price quote from Charles Ball, Emissions & Silencer Technology for an oxidation catalyst for a 500 HP 4SLB engine.
400		\$6,575	\$2,961	\$2,005		\$11,541	\$1,958	\$1,143	\$3,101	\$225	\$0	\$1,643	\$1,643	\$4,744	Memorandum from Tom McGrath, IES to Brad Nelson, EC/R, Request for Additional Cost Detail for Gas-Fired Engines Emission Controls
400		\$6,575	\$2,961	\$2,005		\$11,541	\$1,958	\$1,143	\$3,101	\$225	\$0	\$1,643	\$1,643	\$4,744	Memorandum from Tom McGrath, IES to Brad Nelson, EC/R, Request for Additional Cost Detail for Gas-Fired Engines Emission Controls
425		\$7,149	\$3,025	\$2,005		\$12,179	\$1,756	\$875	\$2,631	\$225	\$0	\$1,734	\$1,734	\$4,365	Memorandum from Tom McGrath, IES to Brad Nelson, EC/R, Request for Additional Cost Detail for Gas-Fired Engines Emission Controls
Assumptions:															
PEC = 118% of purchased equipment cost (PEC).															
DIC = 30% of purchased equipment cost (PEC).															
IIC = 28% of purchased equipment cost (PEC).															
C = 3% of purchased equipment cost (PEC).															
Capital Recovery assumes equipment life of 10 years and 7% interest rate. 0.142377503															
O&M Materials cost covers the annualized equipment cost to replace the catalyst (every 3 years), thermocouples (every 7.5 years), crankcase filters (3 months), and annual catalyst rotation for cleaning. [Source: Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment L (EPA-HQ-OAR-2008-0708-0279)]															
O&M Labor cost covers the annualized labor cost to replace and rotate (for cleaning) catalyst, thermocouples, and crankcase filter. [Source: Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment L (EPA-HQ-OAR-2008-0708-0279)]															

4SLB Oxidation Catalyst Cost (\$2009)

SUMMARY OUTPUT - Total Capital Cost

Regression Statistics

Multiple R	0.989944875
R Square	0.979990856
Adjusted R Square	0.977767618
Standard Error	4727.892942
Observations	11

ANOVA

	df	SS	MS	F	Significance F
Regression	1	9853063606	9853063606	440.7943494	5.91417E-09
Residual	9	201176745.1	22352971.68		
Total	10	10054240351			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	3069.26319	1884.275356	1.62888252	0.137778178	-1193.263795	7331.790175
Engine Size (HP)	12.80450452	0.609880529	20.99510299	5.91417E-09	11.42485892	14.18415013

SUMMARY OUTPUT - Total Annual Cost

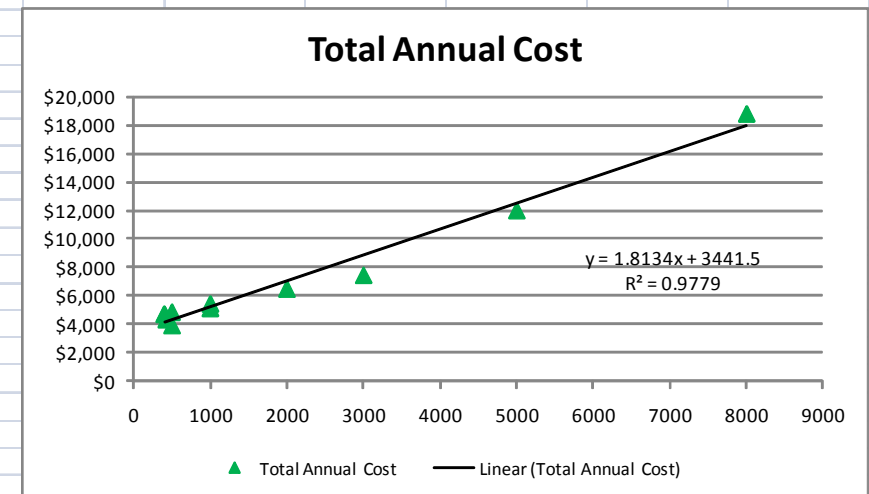
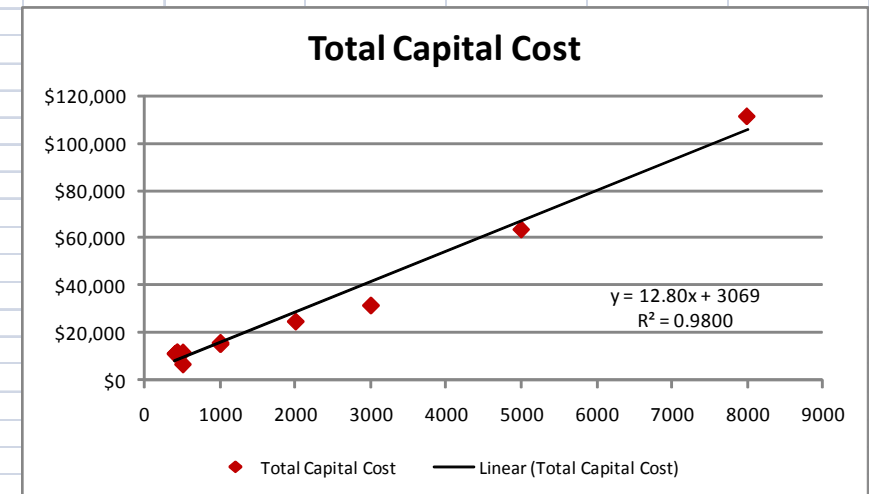
Regression Statistics

Multiple R	0.988903698
R Square	0.977930524
Adjusted R Square	0.97547836
Standard Error	703.9457563
Observations	11

ANOVA

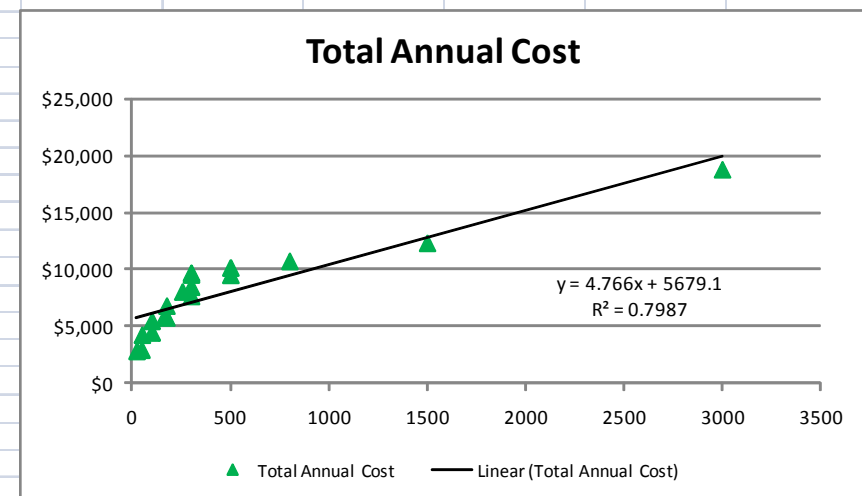
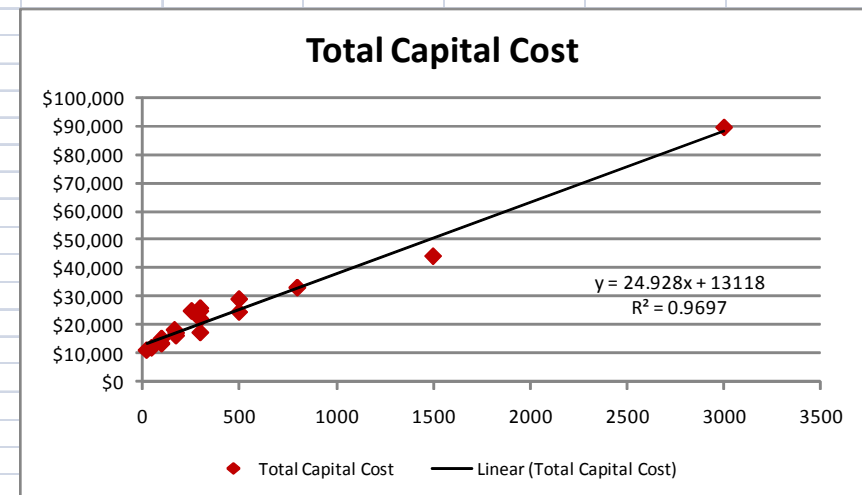
	df	SS	MS	F	Significance F
Regression	1	197622721.6	197622721.6	398.8030634	9.20031E-09
Residual	9	4459856.651	495539.6279		
Total	10	202082578.3			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	3441.504829	280.553654	12.26683303	6.38308E-07	2806.848372	4076.161285
X Variable 1	1.81340819	0.090806373	19.97005417	9.20031E-09	1.607989903	2.018826477



45RB NSCR Costs (\$2009)																
Engine Size (HP)	Equipment Cost	AFRC Cost	Direct Costs		Indirect Costs		Total Capital Cost	Direct Annual Costs			Indirect Annual Costs				Total Annual Cost	Data Source
			PEC	DIC	IIC	C		O&M Materials	O&M Labor	Total Direct Annual Cost (TDAC)	Administrative Charges (ADMC)	Fuel Penalty (FPC)	Capital Recovery (CRC)	Total Indirect Annual Cost (TIAC)		
50			\$8,935				\$11,945	\$664	\$1,275	\$1,939	\$225	\$379	\$1,701	\$2,305	\$4,244	Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment D (EPA-HQ-OAR-2008-0708-0279)
100			\$10,099				\$13,363	\$664	\$1,275	\$1,939	\$225	\$379	\$1,903	\$2,507	\$4,446	Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment D (EPA-HQ-OAR-2008-0708-0279)
100			\$10,827				\$15,139	\$1,071	\$1,320	\$2,391	\$225	\$695	\$2,155	\$3,075	\$5,466	Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment D (EPA-HQ-OAR-2008-0708-0279)
175			\$12,284				\$17,132	\$1,071	\$1,320	\$2,391	\$225	\$695	\$2,439	\$3,359	\$5,750	Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment D (EPA-HQ-OAR-2008-0708-0279)
175			\$10,667				\$16,165	\$1,706	\$1,360	\$3,066	\$225	\$1,200	\$2,302	\$3,727	\$6,793	Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment D (EPA-HQ-OAR-2008-0708-0279)
300			\$16,119				\$22,117	\$1,706	\$1,360	\$3,066	\$225	\$1,200	\$3,149	\$4,574	\$7,640	Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment D (EPA-HQ-OAR-2008-0708-0279)
300			\$11,777				\$17,240	\$2,384	\$1,380	\$3,764	\$225	\$2,021	\$2,455	\$4,701	\$8,465	Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment D (EPA-HQ-OAR-2008-0708-0279)
500			\$16,689				\$24,502	\$2,384	\$1,380	\$3,764	\$225	\$2,021	\$3,489	\$5,735	\$9,499	Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment D (EPA-HQ-OAR-2008-0708-0279)
167	\$2,588	\$7,017	\$11,334	\$3,400	\$3,173	\$340	\$18,247	\$1,071	\$1,320	\$2,391	\$225	\$695	\$2,598	\$3,518	\$5,909	Email from Nick Huff, Miratech to Jennifer Synder, AGTI, SCR Questions for RICE MACT, October 23, 2003 (EPA-HQ-OAR-2005-0029-0038). Cost for NSCR/AFRC on a Caterpillar G3306 adjusted from \$2003 to \$2009.
255	\$6,091	\$7,017	\$15,467	\$4,640	\$4,331	\$464	\$24,902	\$1,706	\$1,360	\$3,066	\$225	\$1,200	\$3,545	\$4,970	\$8,036	Email from Nick Huff, Miratech to Jennifer Synder, AGTI, SCR Questions for RICE MACT, October 23, 2003 (EPA-HQ-OAR-2005-0029-0038). Cost for NSCR/AFRC on a Caterpillar G3408 adjusted from \$2003 to \$2009.
300	\$6,039	\$7,017	\$15,405	\$4,622	\$4,314	\$462	\$24,803	\$2,384	\$1,380	\$3,764	\$225	\$2,021	\$3,531	\$5,777	\$9,541	Email from Nick Huff, Miratech to Jennifer Synder, AGTI, SCR Questions for RICE MACT, October 23, 2003 (EPA-HQ-OAR-2005-0029-0038). Cost for NSCR/AFRC on a Caterpillar G3408 adjusted from \$2003 to \$2009.
300	\$6,113	\$7,500	\$16,063	\$4,819	\$4,498	\$482	\$25,862	\$2,384	\$1,380	\$3,764	\$225	\$2,021	\$3,682	\$5,928	\$9,692	Email from Mike Leonard, Miratech to Brad Nelson, AGTI, Information Request, July 21, 2005 (EPA-HQ-OAR-2005-0030-0087). Cost for NSCR/AFRC on a generic 300 HP rich-burn engine adjusted from \$2005 to \$2009.
500	\$7,800	\$7,500	\$18,054	\$5,416	\$5,055	\$542	\$29,067	\$2,384	\$1,380	\$3,764	\$225	\$2,021	\$4,139	\$6,385	\$10,149	Email from Mike Leonard, Miratech to Brad Nelson, AGTI, Information Request, July 21, 2005 (EPA-HQ-OAR-2005-0030-0087). Cost for NSCR/AFRC on a generic 500 HP rich-burn engine adjusted from \$2005 to \$2009.
800	\$9,924	\$7,500	\$20,561	\$6,168	\$5,757	\$617	\$33,103	\$2,384	\$1,380	\$3,764	\$225	\$2,021	\$4,713	\$6,959	\$10,723	Email from Mike Leonard, Miratech to Brad Nelson, AGTI, Information Request, July 21, 2005 (EPA-HQ-OAR-2005-0030-0087). Cost for NSCR/AFRC on a generic 500 HP rich-burn engine adjusted from \$2005 to \$2009.
1500	\$15,778	\$7,500	\$27,468	\$8,240	\$7,691	\$824	\$44,223	\$2,384	\$1,380	\$3,764	\$225	\$2,021	\$6,296	\$8,542	\$12,306	Email from Mike Leonard, Miratech to Brad Nelson, AGTI, Information Request, July 21, 2005 (EPA-HQ-OAR-2005-0030-0087). Cost for NSCR/AFRC on a generic 500 HP rich-burn engine adjusted from \$2005 to \$2009.
3000	\$39,686	\$7,500	\$55,679	\$16,704	\$15,590	\$1,670	\$89,644	\$2,384	\$1,380	\$3,764	\$225	\$2,021	\$12,763	\$15,009	\$18,773	Email from Mike Leonard, Miratech to Brad Nelson, AGTI, Information Request, July 21, 2005 (EPA-HQ-OAR-2005-0030-0087). Cost for NSCR/AFRC on a generic 500 HP rich-burn engine adjusted from \$2005 to \$2008.
48	\$3,735	\$2,950	\$7,762	\$4,080			\$11,842	\$480	\$540	\$1,020	\$225	\$0	\$1,686	\$1,911	\$2,931	Four Corners Air Quality Task Force Report of Mitigation Options, November 1, 2007. Mitigation Option: Use of NSCR/3-Way Catalysts and Air/Fuel Ratio Controllers on Rich Burn Stoichiometric Engines (EPA-HQ-OAR-2008-0708-0009). TCC includes cost of catalyst housing (\$2,385), catalyst element (\$1,000), AFRC (\$2,950), installation of catalyst housing and support (\$1,380), installation and setup of AFRC (\$2,160), solar panel electricity for AFRC control (\$350), installation of solar panel electricity to AFRC (\$540), and taxes/freight (\$1,077). TDAC includes annual cost for quarterly change of O2 sensor and emissions monitoring (\$320), labor and travel to site (\$540), and annualized cost of catalyst replacement 5 year life (\$160). Cost quoted for a Compresso Ford 460.
23	\$2,925	\$2,950	\$6,952	\$4,080			\$11,032	\$480	\$540	\$1,020	\$225	\$0	\$1,571	\$1,796	\$2,816	Four Corners Air Quality Task Force Report of Mitigation Options, November 1, 2007. Mitigation Option: Use of NSCR/3-Way Catalysts and Air/Fuel Ratio Controllers on Rich Burn Stoichiometric Engines (EPA-HQ-OAR-2008-0708-0009). TCC includes cost of catalyst housing (\$1,775), catalyst element (\$800), AFRC (\$2,950), installation of catalyst housing and support (\$1,380), installation and setup of AFRC (\$2,160), solar panel electricity for AFRC control (\$350), installation of solar panel electricity to AFRC (\$540), and taxes/freight (\$1,077). TDAC includes annual cost for quarterly change of O2 sensor and emissions monitoring (\$320), labor and travel to site (\$540), and annualized cost of catalyst replacement 5 year life (\$160). Cost quoted for a Waukesha 220/330.
Assumptions:																
PEC = 118% of purchased equipment cost (PEC).																
DIC = 30% of purchased equipment cost (PEC).																
IIC = 28% of purchased equipment cost (PEC).																
C = 3% of purchased equipment cost (PEC).																
Direct Annual Cost = (\$5 x Hp) + (14.26 x 5).																
Indirect Annual Cost = 60% of direct annual cost + 4% of total capital cost + capital recovery.																
Capital Recovery assumes equipment life of 10 y 0.142377503																
O&M Materials cost covers the annualized equipment cost to replace the catalyst (every 3 years), thermocouples (every 7.5 years), crankcase filters (3 months), and annual catalyst rotation for cleaning. [Source: Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment D (EPA-HQ-OAR-2008-0708-0279)]																
O&M Labor cost covers the annualized labor cost to replace and rotate (for cleaning) catalyst, thermocouples, and crankcase filter. [Source: Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment D (EPA-HQ-OAR-2008-0708-0279)]																

4SRB NSCR Costs (\$2009)						
SUMMARY OUTPUT - Total Capital Cost						
<i>Regression Statistics</i>						
Multiple R	0.984731321					
R Square	0.969695774					
Adjusted R Square	0.96780176					
Standard Error	3273.282484					
Observations	18					
ANOVA						
	<i>df</i>	<i>SS</i>	<i>MS</i>	<i>F</i>	<i>Significance F</i>	
Regression	1	5485538418	5485538418	511.9791654	1.41597E-13	
Residual	16	171430051.5	10714378.22			
Total	17	5656968469				
	<i>Coefficients</i>	<i>Standard Error</i>	<i>t Stat</i>	<i>P-value</i>	<i>Lower 95%</i>	<i>Upper 95%</i>
Intercept	13117.61245	933.7363075	14.0485192	2.03296E-10	11138.17991	15097.04498
Engine Size (HP)	24.92848169	1.101716069	22.62695661	1.41597E-13	22.59294798	27.26401541
SUMMARY OUTPUT - Total Annual Cost						
<i>Regression Statistics</i>						
Multiple R	0.893674092					
R Square	0.798653382					
Adjusted R Square	0.786069219					
Standard Error	1777.457825					
Observations	18					
ANOVA						
	<i>df</i>	<i>SS</i>	<i>MS</i>	<i>F</i>	<i>Significance F</i>	
Regression	1	200508408.1	200508408.1	63.46495544	5.85557E-07	
Residual	16	50549701.12	3159356.32			
Total	17	251058109.2				
	<i>Coefficients</i>	<i>Standard Error</i>	<i>t Stat</i>	<i>P-value</i>	<i>Lower 95%</i>	<i>Upper 95%</i>
Intercept	5679.133777	507.0374813	11.20061926	5.54849E-09	4604.262341	6754.005214
X Variable 1	4.765983033	0.59825385	7.96648953	5.85557E-07	3.497741535	6.034224532



Wet Seal Degassing Recovery System for Centrifugal Compressors



Technology/Practice Overview

Description

Centrifugal compressors are used throughout the natural gas industry to compress gas for processing, movement through pipelines, and other needs. These compressors require seals around the rotating shaft to prevent high pressure gases from escaping where the shaft exits the compressor casing. Seals may be either wet seals using oil as a barrier or dry seals that use a mechanical barrier with most new compressors equipped with dry seal. However, there are a large number of centrifugal compressors with wet seals in operation. Wet seals use specialty oil which is circulated under higher pressure than the gas in the adjacent compressor case, between rings around the compressor shaft, forming a barrier against the compressed gas leakage. In the wet seal design shown in Exhibit 1, the center ring is attached to the rotating shaft, while

the two rings on each side are stationary in the seal housing, pressed against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. “O-ring” rubber seals prevent leakage around the stationary rings. Very little gas escapes through the oil barrier; considerably more gas is entrained in the oil that comes in direct contact with the high pressures gas at the “inboard” (compressor side) interface, thus contaminating the seal oil. Prior to recirculation, seal oil must be purged of natural gas (which is primarily methane) in a process called seal oil “degassing.” Methane released during degassing is commonly vented to the atmosphere with vent outlets usually located in elevated areas that are not easily accessible to operators for inspection or maintenance (e.g., roof vent stacks). As a result, the majority of methane emissions from a centrifugal compressor often go undetected by operators.

- ☒ Compressors/Engines
- ☐ Dehydrators
- ☐ Directed Inspection & Maintenance
- ☐ Pipelines
- ☐ Pneumatics/Controls
- ☐ Tanks
- ☐ Valves
- ☐ Wells
- ☐ Other

Applicable Sector(s)

- ☒ Production
- ☒ Processing
- ☒ Transmission
- ☒ Distribution

Economic and Environmental Benefits

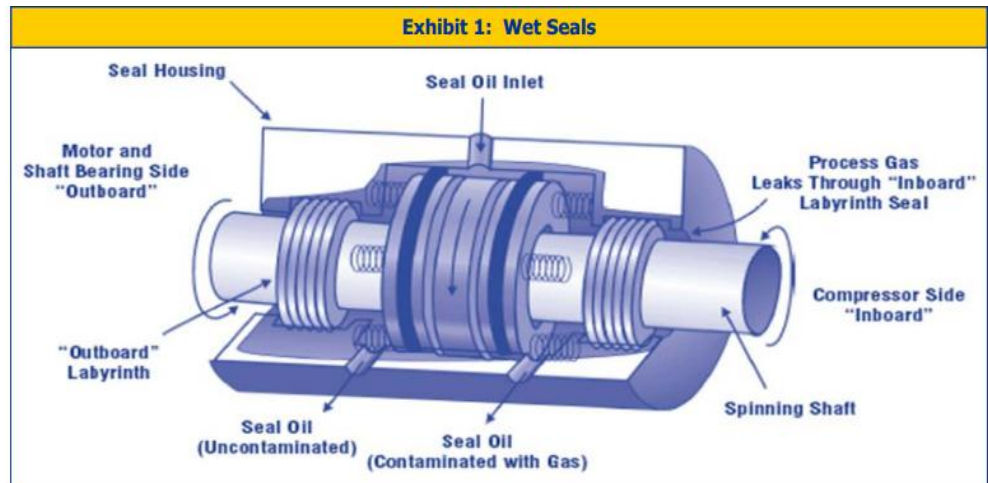
Economics Evaluation

Estimated Gas Price	Annual Methane Savings ¹	Value of Annual Gas Savings	Estimated Implementation Cost	Incremental Operating Cost	Payback
\$3.00/Mcf	30,000 Mcf	\$90,000	\$33,000	Minimal	5 months
	120,000 Mcf	\$360,000	\$90,000		3 months
\$5.00/Mcf	30,000 Mcf	\$150,000	\$33,000	Minimal	3 months
	120,000 Mcf	\$600,000	\$90,000		2 months
\$7.00/Mcf	30,000 Mcf	\$210,000	\$33,000	Minimal	2 months
	120,000 Mcf	\$840,000	\$90,000		1 months

¹ At each gas price, the costs and savings are for one and four compressors at a station.

Wet Seal Degassing Recovery System for Centrifugal Compressors

Exhibit 1: A typical wet seal setup, the seal oil enters through the inlet (top) and provides a barrier to gas attempting to escape by forming two thin films under higher pressure between the center rotating ring and the two stationary rings (seen with surrounding o-rings).



One Partner has reduced methane emissions from centrifugal compressor seal oil degassing by separating gas from seal oil in a small separator/disengagement vessel and routing it back into the compressor suction, to high pressure turbine fuel gas, or to low pressure fuel gas for heaters/burners. A diagram illustrating this partner's approach is shown in Exhibit 2. Seal oil with

entrained gas is typically routed directly to an atmospheric pressure degassing tank from which disengaged gas is vented to the atmosphere. In the capture system, the contaminated seal oil is instead separated from entrained gas in a separator operating at seal oil pressure with gas flow control by a critical orifice. The entrained gas captured from the seal oil is

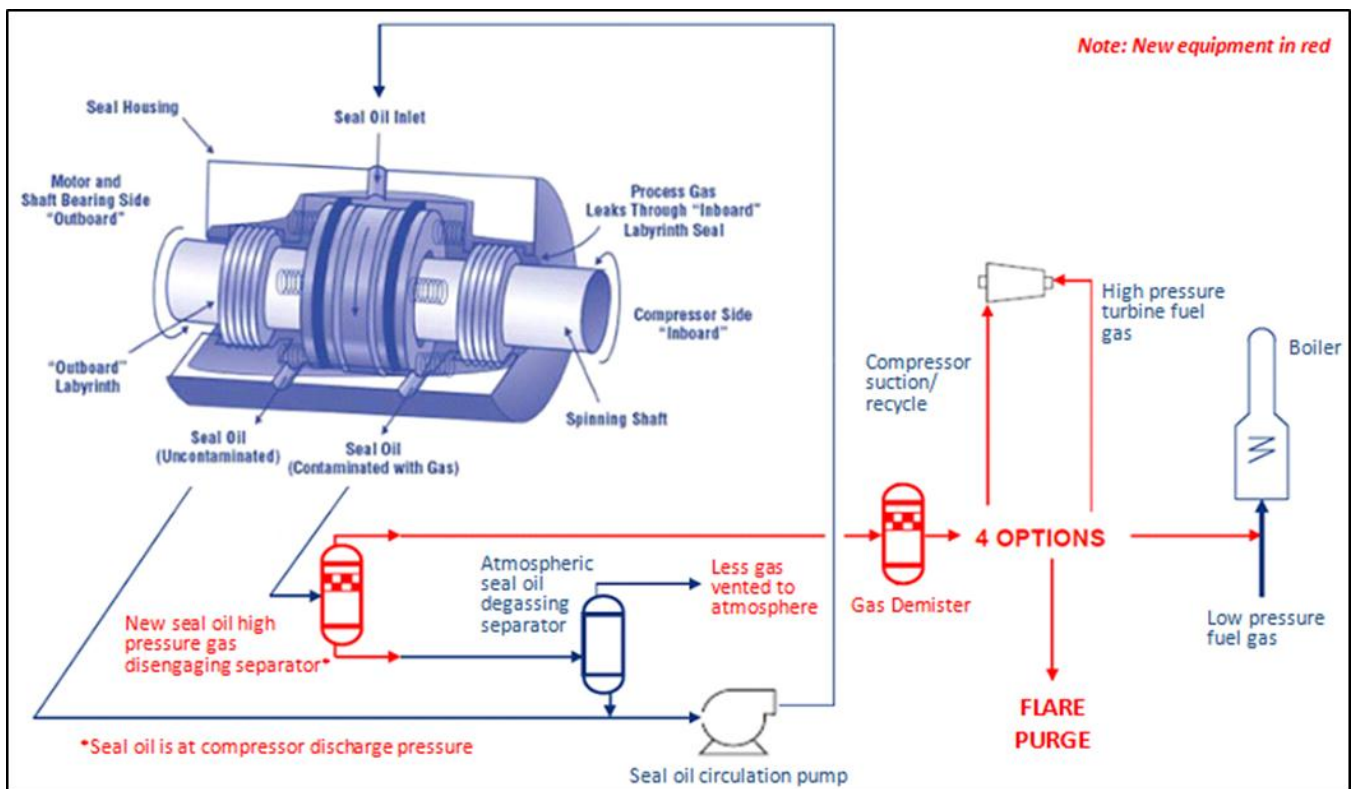


Exhibit 2: General process flow of wet seal degassing recovery system. Existing equipment is shown in blue or black and new equipment for seal oil degassing recovery is shown in red.

Wet Seal Degassing Recovery System for Centrifugal Compressors

routed to a seal oil demister to remove entrained seal oil before routing to beneficial use. The seal oil then flows from the bottom of the seal oil degassing separator to the atmospheric degassing separator where the remaining minimal volume of entrained/dissolved gas is removed and vented to the atmosphere. The regenerated seal oil is then recirculated back to the compressor seal oil system.

Operating Requirements

In order to implement this recovery and use of gas separated from seal oil there must be a use for the recovered gas. Operators may configure the wet seal degassing recovery system to route the recovered gas as low pressure heater/boiler fuel (approximately 50 pounds per square inch gauge [psig]), high pressure turbine fuel (approximately 250 psig), to compressor suction, flare sweep gas, or any combination of the four options. One Partner has configured their wet seal degassing recovery systems to route recovered gas from multiple centrifugal compressors to all four of these choices. If routed to fuel gas use, the small amount of entrained seal oil mist in the gas stream from the new seal oil high pressure gas disengagement separator (shown in red in Exhibit 2 above) requires a demister/filter knock-out vessel (s) be installed to remove residual oil.

Applicability

Wet seal degassing recovery systems could be installed at most locations with wet seal centrifugal compressors, particularly in lieu of retrofitting compressors with dry seals. Retrofitting wet seal centrifugal compressors with dry seals is not always feasible due to operating conditions/requirements, substantial costs, and compressor downtime. Wet seal degassing recovery systems offer an economic alternative to installing dry seals to mitigate methane emissions from wet seal degassing with very little downtime.

Methane Emissions

According to previous measurements of seal oil degassing reported in Bylin, et al. (2009), emissions from degassing centrifugal compressor seal oil can be as high as 185 standard cubic feet per minute (scfm) (5.2 cubic meters (m³) per minute) of gas per compressor, with an average value of 63 scfm (1.8 m³ per minute) of gas per compressor. Gas volume from degassing centrifugal compressor seal oil varies primarily due to: the number of seals per centrifugal compressor, the rate of seal oil circulation, the size of the compressor, and

the compressor discharge pressure. One Partner currently operates wet seal degassing recovery systems that recover 99 percent of the degassing emissions from fifteen centrifugal compressors – four low pressure compressors, nine high pressure compressors, and two tandem compressors at one facility. Based on a study conducted at this particular facility, the wet seal gas recovery system captures 3,300 scfm of gas; that equates to 1.6 billion cubic feet (Bcf) of gas per year (8,500 hours of operation per year as indicated by the Partner). This Partner reports another approximately 85 wet seal centrifugal compressors with the same or similar seal oil gas recovery systems in this particular operation.

Economic Analysis

The analysis for installing a wet seal degassing recovery system should consider the capital and operational costs along with the revenue generated by recovered gas. As shown in the overview table (Economic and Environmental Benefits) above, the economics for recovering wet seal degassing losses are compelling at even low gas prices. The detailed economic analysis in Exhibit 3 below presents two scenarios. The first scenario depicts the wet seal degassing recovery system installed for one centrifugal compressor, and the second scenario illustrates a wet seal degassing recovery system installed at a centrifugal compressor station with four centrifugal compressors. These examples are based on one Partner's emissions measurements, savings, and installed equipment costs which have high pressure gas disengagement separators on each seal of 15 compressors, with one recovered gas two stage filter/demister system.

Capital Costs

The investment per compressor to recover seal oil degassing emissions using this technology includes the cost of a high pressure seal oil gas disengagement separator for each compressor seal or pair of seals operating at the same seal oil pressure, new piping, the appropriate pressure and flow controls, and the labor to design and install the equipment. Operating and maintenance (O&M) costs are expected to be minimal. The investment per station to condition the recovered degassing emissions for injection into a low pressure fuel system would include the cost of a gas demister to remove residual seal oil from the recovered gas. If the recovered gas is routed to a higher pressure turbine fuel system, a second seal oil high efficiency filter/separator

Wet Seal Degassing Recovery System for Centrifugal Compressors

is likely required to ensure all remaining seal oil mist is removed.

The capital cost (estimated) for each separator includes the purchase cost of the process vessel, piping, instrumentation, structural support, electrical, painting, shipping, insurance, and installation. Exhibit 3 summarizes the estimated capital costs for each piece of equipment installed in a wet seal degassing recovery system.

design pressure of 720 psig. The cost for a seal oil single-stage demister/filter system designed for a single centrifugal compressor or a compressor station with four centrifugal compressors is \$9,000.

If any of the recovered gas is being used as high pressure turbine fuel, the recovery system may include a second seal oil gas high-efficiency filter to ensure trace amounts of seal oil do not foul the turbine fuel injectors. This economic analysis assumes the seal oil gas filter

Exhibit 3: Wet Seal Degassing Recovery System Installation and Equipment Costs

Equipment	One Centrifugal Compressor Capital Cost (\$2011)	Centrifugal Compressor Station Capital Cost (\$2011)
Seal-Oil/Gas Separator ¹	\$19,000	\$76,000
Seal Oil Gas Demister – Low Quality Gas	\$9,000	\$9,000
Seal Oil Gas Demister – High Quality Gas	\$5,000	\$5,000
Total	\$33,000	\$90,000

¹ Assuming two seals per centrifugal compressor and four centrifugal compressors at the station. An individual high pressure seal oil gas separator costs \$9,500 per seal.

High Pressure Seal Oil Gas Disengagement Separators

For each centrifugal compressor connected to the wet seal degassing recovery system, a seal oil gas separator will be installed for each seal or pair of seals if operating at the same seal oil pressure. The seal oil gas separators can be designed to operate at the same pressure as the seal oil exiting the seal housing. Based on a Partner's installation, the size of these separators assumes 1-foot diameter, 3-foot height seal oil gas separators with a 1,125 psig design pressure and made of carbon steel. The total cost of each seal oil gas separator is \$9,500; assuming two seal-oil/gas separators per compressor, the total cost per compressor is \$19,000.

Seal Oil Recovered Gas Demister/Filter

Before the recovered gas can be sent to a fuel line it must pass through at least one high-efficiency demister to remove entrained seal oil that may foul burners and potentially clog fuel injectors. The seal oil gas demister can be designed to receive recovered gas from multiple centrifugal compressors with wet seals. Therefore, the design characteristics of this vessel will vary depending on the number of centrifugal compressors connected to the vessel. Based on a Partner's installation, this economic analysis assumes, for a single centrifugal compressor, the seal oil gas demister will be vertical and have a 1-foot diameter and 4-foot height with a

for turbine fuel quality gas will be vertical and have a 1-foot diameter and 3-foot height with a design pressure of 300 psig and be made of carbon steel. The cost for the second seal oil high-efficiency filter for a single centrifugal compressor or a compressor station is \$5,000.

Piping and Instrumentation

Operators will need to route seal oil exiting the compressor seal to the new seal-oil/gas separator and then to the degassing tank which will require piping modifications. Additionally, pipes and valves to transport the recovered gas from the seal oil gas disengagement separators to the seal oil gas demister/filters and further to the fuel gas, compressor suction or flare line(s) will be required. Pressure and flow controls will also need to be installed to regulate the pressure and flow of the recovered gas from each high pressure seal oil degassing separator. In this Partner's installations this is accomplished with a critical orifice (1/16 inch/1.59 mm) on the gas outlet from each seal-oil/gas separator which restricts gas flow using choke flow effects. For example, this Partner has set up the wet seal degassing recovery system to route captured gas to a high pressure turbine fuel line, low pressure process heater fuel line, and flare purge which requires additional instrumentation and flow control. The majority of the gas is routed to the high pressure

Wet Seal Degassing Recovery System for Centrifugal Compressors

turbine fuel line with excess gas routed to the low pressure process heater fuel line or flare, depending on fuel requirements. The piping and instrumentation costs are included in the installation and capital costs for each individual piece of equipment listed in Exhibit 3.

Estimated Savings

The savings for capturing seal oil degassing emissions are realized by generating additional gas sales and revenue through using recovered gas for site fuel gas or recycling directly to suction and sales or processing. Based on the measurement studies discussed in Bylin, et al. (2009), the average methane emissions from centrifugal compressor wet seal degassing is 63 scfm (1.8 m3 per minute) of gas per compressor. Assuming 8,000 hours of operation per year, the total gas emissions per year is 30 million cubic feet (MMcf) per compressor. Based on one Partner's experience, over 99 percent of the entrained gas in the seal oil was captured and used as fuel – proving this technology performs as well as dry seal systems from an emission perspective. This analysis assumes 99 percent of the potential degassing emissions are captured and 1 percent is vented. Therefore, 30 MMcf of gas is recovered per

centrifugal compressor and displaces the same volume in fuel gas or is routed to compressor suction and sales. At \$3.00 per thousand cubic feet (Mcf), savings from reduced fuel gas consumption is estimated to be \$90,000 per year per centrifugal compressor connected to a wet seal degassing recovery system. A station with four centrifugal compressors connected to a wet seal degassing recovery system could potentially generate \$360,000 per year of additional revenue.

Comparing Costs to Savings

The economics of implementing a wet seal degassing recovery system is shown below using a five-year cash flow table. This analysis presented in Exhibit 4 and Exhibit 5 considers capital costs and methane emissions savings. The capital and installation costs in this economic analysis assume the operator installs both the seal oil gas demister/filter separator for low pressure fuel gas and seal oil gas high efficiency filter for high pressure turbine fuel gas, which will allow the operator to route to a flare, low pressure burner, or turbine fuel line. Exhibit 3 shows the detailed breakdown of the equipment and capital cost used in this economic analysis. It is important to note that all analyses will be highly site-specific, but the economics of installing a wet

Exhibit 4: Wet Seal Degassing Recovery System Costs and Savings for One Compressor

Costs and Savings (\$)	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Wet seal recovery system capital & installation costs	(\$33,000)					
Annual natural gas savings (\$3.00/Mcf of Methane)		\$90,000	\$90,000	\$90,000	\$90,000	\$90,000
NPV (Net Present Value) = \$280,000 IRR (Internal Rate of Return) = 270% Payback Period = 5 months						

Exhibit 5: Wet Seal Degassing Recovery System Costs and Savings for Four Compressors at a Station

Costs and Savings (\$)	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Wet seal recovery system capital & installation costs	(\$90,000)					
Annual natural gas savings (\$3.00/Mcf of Methane)		\$360,000	\$360,000	\$360,000	\$360,000	\$360,000
NPV (Net Present Value) = \$1,200,000 IRR (Internal Rate of Return) = 400% Payback Period = 3 months						

Wet Seal Degassing Recovery System for Centrifugal Compressors

seal gas recovery system are so attractive that companies should consider implementing this technology at any and all facilities with at least one centrifugal compressor with wet seals.

Exhibit 4 presents the economics of installing a wet seal degassing recovery system for a single centrifugal compressor. Exhibit 5 presents the economics of installing a wet seal degassing recovery system at a station with four centrifugal compressors. The net present value and payback period are calculated using a 10 percent discount rate.

Operational Reliability

The Partner reporting the seal oil degassing systems reports them being in place with constant use since 1977 and no failures due to the degassing systems. With about 100 such systems installed and operating from very low pressures to very high pressures across a range of gas compositions, the operational reliability of seal oil degassing systems has been clearly demonstrated.

Discussion

A wet seal oil degassing recovery system is likely to provide the lowest cost for retrofit with the quickest payback for compressor stations, offshore production platforms or gas processing plants with single or multiple wet seal centrifugal compressors. All options pay back in less than a year. The economics are compelling, but the installation may require a brief shut-down of each compressor to tie the seal oil circulation piping into the new gas disengagement vessels. New facilities requiring the installation of wet seal centrifugal compressors can also integrate wet seal degassing recovery systems into their process design at the same costs. As demonstrated by a Partner facility, wet seal degassing recovery systems are highly effective at capturing degassing emissions from wet seal centrifugal compressors and subsequently reducing fuel gas purchases and/or increasing gas sales with a high rate of return.

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While we have taken steps to ensure the accuracy of this Internet version of the document, it is not the official version. To see a complete version including any recent edits, visit: <https://www.ecfr.gov/cgi-bin/ECFR?page=browse> and search under Title 40, Protection of Environment.

METHOD 22—VISUAL DETERMINATION OF FUGITIVE EMISSIONS FROM MATERIAL SOURCES AND SMOKE EMISSIONS FROM FLARES

NOTE: This method is not inclusive with respect to observer certification. Some material is incorporated by reference from Method 9.

1.0 Scope and Application

This method is applicable for the determination of the frequency of fugitive emissions from stationary sources, only as specified in an applicable subpart of the regulations. This method also is applicable for the determination of the frequency of visible smoke emissions from flares.

2.0 Summary of Method

2.1 Fugitive emissions produced during material processing, handling, and transfer operations or smoke emissions from flares are visually determined by an observer without the aid of instruments.

2.2 This method is used also to determine visible smoke emissions from flares used for combustion of waste process materials.

2.3 This method determines the amount of time that visible emissions occur during the observation period (*i.e.*, the accumulated emission time). This method does not require that the opacity of emissions be determined. Since this procedure requires only the determination of whether visible emissions occur and does not require the determination of opacity levels, observer certification according to the procedures of Method 9 is not required. However, it is necessary that the observer is knowledgeable with respect to the general procedures for determining the presence of visible emissions. At a minimum, the observer must be trained and knowledgeable regarding the effects of background contrast, ambient lighting, observer position relative to lighting, wind, and the presence of uncombined water (condensing water vapor) on the visibility of emissions. This training is to be obtained from written materials found in References 1 and 2 or from the lecture portion of the Method 9 certification course.

3.0 Definitions

3.1 *Emission frequency* means the percentage of time that emissions are visible during the observation period.

3.2 *Emission time* means the accumulated amount of time that emissions are visible during the observation period.

3.3 *Fugitive emissions* means emissions generated by an affected facility which is not collected by a capture system and is released to the atmosphere. This includes emissions that (1) escape capture by process equipment exhaust hoods; (2) are emitted during material transfer; (3) are emitted from buildings housing material processing or handling equipment; or (4) are emitted directly from process equipment.

3.4 *Observation period* means the accumulated time period during which observations are conducted, not to be less than the period specified in the applicable regulation.

3.5 *Smoke emissions* means a pollutant generated by combustion in a flare and occurring immediately downstream of the flame. Smoke occurring within the flame, but not downstream of the flame, is not considered a smoke emission.

4.0 *Interferences*

4.1 Occasionally, fugitive emissions from sources other than the affected facility (*e.g.*, road dust) may prevent a clear view of the affected facility. This may particularly be a problem during periods of high wind. If the view of the potential emission points is obscured to such a degree that the observer questions the validity of continuing observations, then the observations shall be terminated, and the observer shall clearly note this fact on the data form.

5.0 *Safety*

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

6.0 *Equipment*

6.1 Stopwatches (two). Accumulative type with unit divisions of at least 0.5 seconds.

6.2 Light Meter. Light meter capable of measuring illuminance in the 50 to 200 lux range, required for indoor observations only.

7.0 *Reagents and Supplies [Reserved]*

8.0 *Sample Collection, Preservation, Storage, and Transfer [Reserved]*

9.0 *Quality Control [Reserved]*

10.0 *Calibration and Standardization [Reserved]*

11.0 *Analytical Procedure*

11.1 Selection of Observation Location. Survey the affected facility, or the building or structure housing the process to be observed, and determine the locations of potential emissions. If the

affected facility is located inside a building, determine an observation location that is consistent with the requirements of the applicable regulation (*i.e.*, outside observation of emissions escaping the building/structure or inside observation of emissions directly emitted from the affected facility process unit). Then select a position that enables a clear view of the potential emission point(s) of the affected facility or of the building or structure housing the affected facility, as appropriate for the applicable subpart. A position at least 4.6 m (15 feet), but not more than 400 m (0.25 miles), from the emission source is recommended. For outdoor locations, select a position where the sunlight is not shining directly in the observer's eyes.

11.2 Field Records.

11.2.1 Outdoor Location. Record the following information on the field data sheet (Figure 22-1): Company name, industry, process unit, observer's name, observer's affiliation, and date. Record also the estimated wind speed, wind direction, and sky condition. Sketch the process unit being observed, and note the observer location relative to the source and the sun. Indicate the potential and actual emission points on the sketch. Alternatively, digital photography as described in section 11.2.3 may be used for a subset of the recordkeeping requirements of this section.

11.2.2 Indoor Location. Record the following information on the field data sheet (Figure 22-2): Company name, industry, process unit, observer's name, observer's affiliation, and date. Record as appropriate the type, location, and intensity of lighting on the data sheet. Sketch the process unit being observed, and note the observer location relative to the source. Indicate the potential and actual fugitive emission points on the sketch. Alternatively, digital photography as described in section 11.2.3 may be used for a subset of the recordkeeping requirements of this section.

11.2.3 Digital Photographic Records. Digital photographs, annotated or unaltered, may be used to record and report sky conditions, observer's location relative to the source, observer's location relative to the sun, process unit being observed, potential emission points and actual emission points for the requirements in sections 11.2.1 and 11.2.2. The image must have the proper lighting, field of view and depth of field to properly distinguish the sky condition (if applicable), process unit, potential emission point and actual emission point. At least one digital photograph must be from the point of the view of the observer. The photograph(s) representing the environmental conditions including the sky conditions and the position of the sun relative to the observer and the emission point must be taken within a reasonable time of the observation (*i.e.*, 15 minutes). When observations are taken from exactly the same observation point on a routine basis (*i.e.*, daily) and as long as there are no modifications to the units depicted, only a single photograph each is necessary to document the observer's location relative to the emissions source, the process unit being observed, and the location of potential and actual emission points. Any photographs altered or annotated must be retained in an unaltered format for recordkeeping purposes.

11.3 Indoor Lighting Requirements. For indoor locations, use a light meter to measure the level of illumination at a location as close to the emission source(s) as is feasible. An illumination of greater than 100 lux (10 foot candles) is considered necessary for proper application of this method.

11.4 Observations.

11.4.1 Procedure. Record the clock time when observations begin. Use one stopwatch to monitor the duration of the observation period. Start this stopwatch when the observation period begins. If the observation period is divided into two or more segments by process shutdowns or observer rest breaks (see section 11.4.3), stop the stopwatch when a break begins and restart the stopwatch without resetting it when the break ends. Stop the stopwatch at the end of the observation period. The accumulated time indicated by this stopwatch is the duration of observation period. When the observation period is completed, record the clock time. During the observation period, continuously watch the emission source. Upon observing an emission (condensed water vapor is not considered an emission), start the second accumulative stopwatch; stop the watch when the emission stops. Continue this procedure for the entire observation period. The accumulated elapsed time on this stopwatch is the total time emissions were visible during the observation period (*i.e.*, the emission time.)

11.4.2 Observation Period. Choose an observation period of sufficient length to meet the requirements for determining compliance with the emission standard in the applicable subpart of the regulations. When the length of the observation period is specifically stated in the applicable subpart, it may not be necessary to observe the source for this entire period if the emission time required to indicate noncompliance (based on the specified observation period) is observed in a shorter time period. In other words, if the regulation prohibits emissions for more than 6 minutes in any hour, then observations may (optional) be stopped after an emission time of 6 minutes is exceeded. Similarly, when the regulation is expressed as an emission frequency and the regulation prohibits emissions for greater than 10 percent of the time in any hour, then observations may (optional) be terminated after 6 minutes of emission are observed since 6 minutes is 10 percent of an hour. In any case, the observation period shall not be less than 6 minutes in duration. In some cases, the process operation may be intermittent or cyclic. In such cases, it may be convenient for the observation period to coincide with the length of the process cycle.

11.4.3 Observer Rest Breaks. Do not observe emissions continuously for a period of more than 15 to 20 minutes without taking a rest break. For sources requiring observation periods of greater than 20 minutes, the observer shall take a break of not less than 5 minutes and not more than 10 minutes after every 15 to 20 minutes of observation. If continuous observations are desired for extended time periods, two observers can alternate between making observations and taking breaks.

11.5 Recording Observations. Record the accumulated time of the observation period on the data sheet as the observation period duration. Record the accumulated time emissions were observed on the data sheet as the emission time. Record the clock time the observation period began and ended, as well as the clock time any observer breaks began and ended.

12.0 Data Analysis and Calculations

If the applicable subpart requires that the emission rate be expressed as an emission frequency (in percent), determine this value as follows: Divide the accumulated emission time (in seconds)

by the duration of the observation period (in seconds) or by any minimum observation period required in the applicable subpart, if the actual observation period is less than the required period, and multiply this quotient by 100.

13.0 Method Performance [Reserved]

14.0 Pollution Prevention [Reserved]

15.0 Waste Management [Reserved]

16.0 References

1. Missan, R., and A. Stein. Guidelines for Evaluation of Visible Emissions Certification, Field Procedures, Legal Aspects, and Background Material. EPA Publication No. EPA-340/1-75-007. April 1975.
2. Wohlschlegel, P., and D.E. Wagoner. Guideline for Development of a Quality Assurance Program: Volume IX—Visual Determination of Opacity Emissions from Stationary Sources. EPA Publication No. EPA-650/4-74-005i. November 1975.

17.0 Tables, Diagrams, Flowcharts, and Validation Data

FUGITIVE OR SMOKE EMISSION INSPECTION OUTDOOR LOCATION			
Company Location Company Rep.	Observer Affiliation Date		
Sky Conditions Precipitation	Wind Direction Wind Speed		
Industry	Process Unit		
Sketch process unit: indicate observer position relative to source; indicate potential emission points and/or actual emission points.			
OBSERVATIONS	Clock Time	Observation period duration, min:sec	Accumulated emission time, min:sec
Begin Observation	_____	_____	_____
	_____	_____	_____
	_____	_____	_____
	_____	_____	_____
	_____	_____	_____
	_____	_____	_____
	_____	_____	_____
	_____	_____	_____
End Observation	_____	_____	_____

Figure 22-1

FUGITIVE OR SMOKE EMISSION INSPECTION INDOOR LOCATION			
Company Location Company Rep.		Observer Affiliation Date	
Industry		Process Unit	
Light type (fluorescent, incandescent, natural) Light location (overhead, behind observer, etc.) Illuminance (lux or footcandles) Sketch process unit: indicate observer position relative to source; indicate potential emission points and/or actual emission points.			
OBSERVATIONS	Clock Time	Observation period duration, min:sec	Accumulated emission time, min:sec
Begin	_____	_____	_____
	_____	_____	_____
	_____	_____	_____
	_____	_____	_____
	_____	_____	_____
	_____	_____	_____
	_____	_____	_____
	_____	_____	_____
	_____	_____	_____
End Observation	_____	_____	_____

Figure 22-2

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Baseline 2014-2016 Oil and Gas Emission Inventory for the WESTAR-WRAP Region

Baseline 2014-2016 Oil and Gas Emission Inventory for the WESTAR-WRAP Region

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EXECUTIVE SUMMARY

This study provides estimates of criteria air pollutant and greenhouse gas emissions for oil and gas (O&G) exploration and production operations in the Western States Air Resources Council-Western Regional Air Partnership (WESTAR-WRAP) region for a 2014-2016 baseline period. This analysis was sponsored by the Western Regional Air Partnership Oil and Gas Working Group (WRAP OGWG).

The WESTAR-WRAP region consists of 15 states in the Western US, several of which have substantial O&G exploration and production activities. Accurate O&G emission inventories are critical for air quality, including regional haze planning. In 2014, O&G activity in the WESTAR-WRAP Region included close to 12,000 spuds, over 225,000 active O&G wells, over 9 trillion cubic feet of natural gas production, and over 1 billion barrels of oil production. Over 70% of active wells in the WESTAR-WRAP region in 2014 were vertical wells and over 75% of spuds were horizontal or directional wells, indicating a shift from development of vertical to horizontal and directional wells.

To develop the baseline 2014-2016 WESTAR-WRAP region emission inventory base year 2014 emissions were compiled from existing emission inventory sources (described in Section 2.1). Subsequent to compilation of the base year 2014 emission inventory, outreach was conducted to gather additional data from regulatory agencies and upstream O&G operators to enhance the emissions inventory and, to the extent that data was provided, make the inventory applicable to the 2014-2016 baseline period (described in Section 2.2). A survey data collection effort was used to collect new information to enhance emission inventory accuracy as part of the outreach effort. Survey data collection targeted specific equipment types, production areas, and operators that could substantially enhance the WESTAR-WRAP O&G emission inventory. The survey was first distributed to state agencies so that in-house agency data could be leveraged prior to asking O&G operators to provide survey data. After state agencies filled out the survey, it was distributed to O&G operators to fill remaining data gaps. O&G emissions from California are excluded from this analysis since California Air Resources Board is developing O&G emissions independently and results were not available for inclusion in this report.

Integrating the data collected as part of survey outreach into the 2014-2016 baseline emission inventory resulted in NOx emissions increases of 8% over the WESTAR-WRAP region compared the base year 2014 WRAP emission inventory. Hydraulic fracturing engine emissions accounted for 47% of nitrogen oxides (NOx) emission increases and emissions from artificial lift engines accounted for 38% of NOx emissions increases. Volatile organic compound (VOC) emissions decreased by 22% over the WESTAR-WRAP region based on integration of operator survey data into the inventory, primarily as a result of increases to oil tank control prevalence.

State-level WESTAR-WRAP region O&G emissions by state are presented in Table ES-1.

Table ES-1. WESTAR-WRAP region O&G emissions by state.

Pollutant	Criteria Air Pollutant Emissions (tons/yr) and Greenhouse Gas Emissions (1000 tons/yr)												
	AK	AZ	CO	ID	MT	ND	NM	NV	OR	SD	UT	WA	WY
NOx	43,291	1,960	65,985	889	9,265	57,706	78,940	156	454	693	16,379	444	46,171
VOC	27,449	280	189,113	34	35,714	197,658	185,088	269	73	3,090	112,485	36	264,821
CO	13,607	439	56,710	272	7,955	52,690	113,550	111	263	496	14,145	301	21,384
SOx	2,156	33	710	4	946	9,574	23,155	15	13	13	586	14	6,888
PM ₁₀	1,166	51	1,929	10	170	1,336	2,393	11	20	77	706	14	1,276
PM _{2.5}	1,098	51	1,929	10	170	1,336	2,393	11	20	77	706	14	1,276

Pollutant	Criteria Air Pollutant Emissions (tons/yr) and Greenhouse Gas Emissions (1000 tons/yr)												
	AK	AZ	CO	ID	MT	ND	NM	NV	OR	SD	UT	WA	WY
CO ₂	N/A	1,183	11,101	245	2,254	18,303	19,954	99	210	584	5,777	201	11,096
CH ₄	N/A	1	225	<1	138	247	705	<1	<1	4	529	<1	365
N ₂ O	N/A	<1	<1	<1	<1	<1	<1	<1	<1	<1	<1	<1	<1
CO ₂ (e)	N/A	1,209	18,583	248	5,712	24,541	37,677	108	216	699	19,034	203	20,304

The contents of the report by Chapter are summarized as follows:

- Chapter 1.0 provides introductory information on study methodology, scope, and O&G activity in the WESTAR-WRAP region;
- Chapter 2.0 describes the steps taken to compile the emission inventory based on reference inventories, agency submitted data, and survey responses;
- Chapter 3.0 presents summaries of baseline 2014-2016 emissions.

1.0 INTRODUCTION

The WRAP OGWG is sponsoring the development of O&G emission inventories as part of efforts to support regional haze planning in the Western States Air Resources Council-Western Regional Air Partnership (WESTAR-WRAP) region. The O&G emission inventories developed under WRAP OGWG sponsorship will also facilitate other types of air quality planning (e.g., photochemical ozone modeling). More information about WRAP OGWG emission inventory development efforts may be found at the project webpage: <https://www.wrapair2.org/ogwg.aspx>.

This report describes the development of a criteria air pollutant and greenhouse gas (GHG) emissions inventory for O&G field operations in the WESTAR-WRAP region for a baseline 2014-2016 period, including point (midstream) and nonpoint (wellsite) sources. The baseline emissions inventory was compiled based on existing emission inventory sources and improvements based on collected survey data.

1.1 Scope

1.1.1 Sources

The emission inventory documented herein includes emissions from upstream and midstream O&G sources, consistent with the OGWG Road Map Scope of Work¹ and the OGWG Roadmap Phase I Report (Grant et al., 2018b). Downstream O&G emissions are not included. The baseline O&G emission inventory includes wellsite, gathering, and processing subsectors (items 1, 5, and 6 in Figure 1-1). Item 1) On-shore Petroleum and Natural Gas Production is referred to as "wellsite" sources; emissions from wellsite sources are typically classified as nonpoint sources². Items 5) Gathering and Boosting and 6) Gas Processing Plant are collectively referred to as "midstream" sources; emissions from midstream sources are typically classified as point sources. The classification of well-site emissions as nonpoint and midstream emissions as point sources is consistent with O&G emission inventory classifications used in the WRAP Phase III study³, West-wide Jumpstart Air Quality Modeling Study (WestJUMP AQMS)⁴, 2011 Western Air Quality Study⁵, and 2014 NEI methodology⁶.

¹ https://www.wrapair2.org/pdf/11162017_WRAPOGWGWorkgroup_RoadMapSOW.pdf

² There are exceptions; for example, several wellsite sources in the Uinta Basin are available by facility and will be included in emission inventories as point source emissions.

³ <https://www.wrapair2.org/PhaseIII.aspx>

⁴ <https://www.wrapair2.org/WestJumpAQMS.aspx>

⁵ <http://vibe.cira.colostate.edu/wiki/wiki/1018/3saqs-2011a-modeling-platform>

⁶ <https://www.epa.gov/air-emissions-inventories/2014-national-emissions-inventory-nei-technical-support-document-tsd>

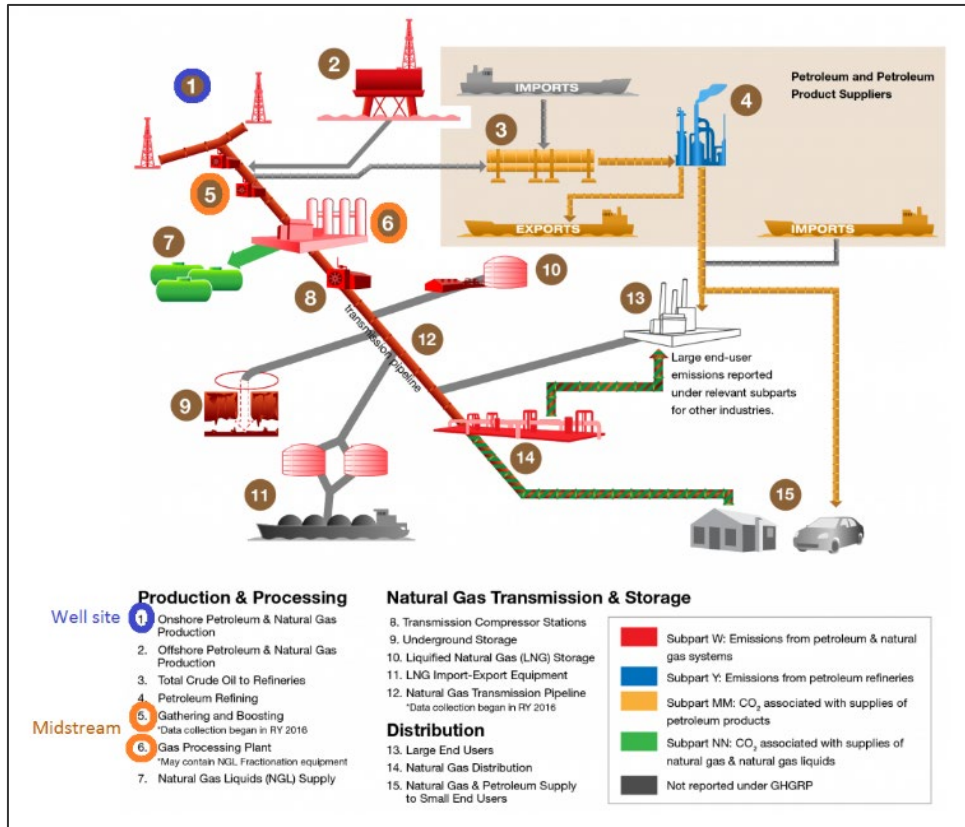


Figure 1-1. Example Petroleum and Natural Gas Industry schematic^{7,8}.

1.1.2 Geographical Scope

The WESTAR-WRAP region includes 15 states, several of which have substantial O&G production and generate substantial O&G emissions. Figure 1-2 shows major basins in the WESTAR-WRAP region. California O&G emissions are estimated by the California Air Resources Board and are not included herein. Several states have limited or zero O&G production and O&G sector emissions: Arizona, Hawaii, Idaho, Nevada, Oregon, South Dakota, and Washington. Emissions were estimated by county, distinguishing between tribal and non-tribal sources.

⁷ Source: <https://www.epa.gov/ghgreporting/ghgrp-and-oil-and-gas-industry>

⁸ This figure shows O&G subsectors for which emissions have been developed in this study. It is important to consider that Petroleum and Natural Gas Industry equipment is typically tailored to meet field, basin, and/or region-specific infrastructure requirements.

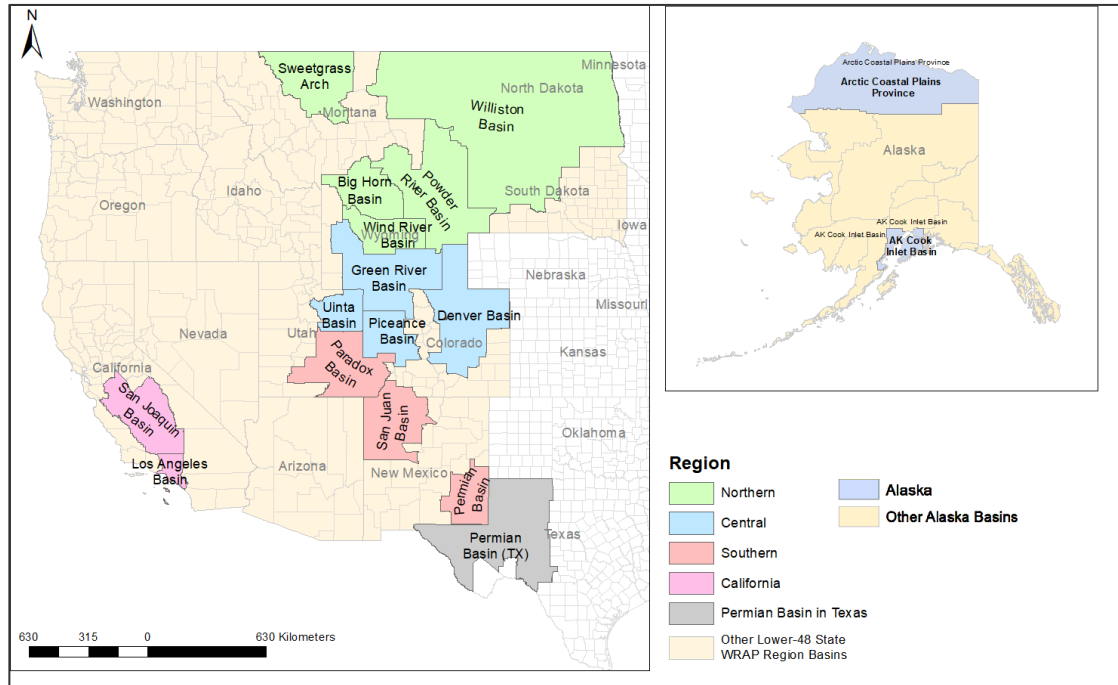


Figure 1-2. WESTAR-WRAP region, including major O&G basins.

1.1.3 Temporal Scope

The baseline emission inventory was developed with annual emissions for the baseline period 2014-2016. Base year 2014 emission inventories that were the basis of the emission inventory compilation were updated, to the extent that data was made available, to include updated 2014-2016 emission inventory inputs provided by regulatory agencies and O&G operators. In general, midstream facility emissions are derived from state and federal agency data for calendar year 2014. Wellsite input factors were developed for activities in calendar year 2014, with updates to input factors as described in Section 2.2. All well count and production data used to develop the emission inventory were obtained from the IHS Enerdeq database for calendar year 2014.

1.1.4 Pollutants

Emissions were estimated for the following pollutants;

- Nitrogen oxide (NO_x)
- Volatile organic compounds (VOC)
- Carbon monoxide (CO)
- Particular matter less than 10 microns (PM₁₀)
- Particulate matter less than 2.5 microns (PM_{2.5})
- Sulfur oxides (SO_x)
- Carbon dioxide (CO₂)
- Methane (CH₄)
- Nitrous oxide (N₂O)

1.2 Well Count and Production Data

Oil and gas related activity data were obtained from the IHS Enerdeq database⁹ queried via online interface. The IHS Enerdeq database uses data from each state's Oil and Gas Conservation Commission (OGCC or equivalent) as sources of information for oil and gas activity. This data is also available directly through database querying tools maintained by the respective agencies. It was determined that the IHS database is more accurate and complete than the state databases. The IHS database was also used to develop emission inventories in the WRAP Phase III, WestJump AQMS, and IWDW studies. Therefore, the IHS database was chosen as the basis for O&G activity statistics for this analysis. Two types of data were queried from the Enerdeq database: production data and well data. Production data includes information relevant to producing wells while well data includes information relevant to drilling activity ("spuds") and completions.

Production data were obtained for all counties in the WRAP region as IHS "298" format data files. The "298" well data contain information regarding historical O&G production. The "298" well data were processed with a PERL script to develop a database by American Petroleum Institute (API)-number, well type (oil, gas, or coalbed methane; CBM), spud type (directional, horizontal, or vertical), annual gas production, oil production, and water production with latitude and longitude information.

The API number in the IHS database consists of 14 digits as follows:

- Digits 1 to 2: state identifier
- Digits 3 to 5: county identifier
- Digits 6 to 10: borehole identifier
- Digits 11 to 12: sidetracks
- Digits 13 to 14: event sequence code (recompletions)

Based on the expectation that the first 10 digits, which include geographic and borehole identifiers, would predict unique sets of well head equipment, the unique wells were identified by the first 10 digits of the API number.

Well data were also obtained from the IHS Enerdeq database for all WRAP region states as IHS "297" well data. The "297" well data contain information on spuds and completions. The "297" well data were processed with a PERL script to arrive at a database of by-API-number and spud type, spud and completion dates with latitude and longitude information. Drilling events in 2014 were identified by indication that the spud occurred within 2014. If the well API number indicated the well was a recompletion, it was not counted as a drilling event, but if the API number indicated the well was a sidetrack, it was counted as a drilling event.

O&G activity for the WRAP Region states is summarized in Table 1-1; details by basin, spud type and well types are available in the 2014 O&G activity spreadsheet¹⁰.

⁹ All data queried from IHS Enerdeq is subject to copyright protections

¹⁰ https://www.wrapair2.org/pdf/WESTAR_OG_Activity_10Aug2018_distributed.xlsx

Table 1-1. WESTAR-WRAP region 2014 O&G activity by state.

State	Spud Count	Active Well Count	Gas Production (BCF/yr)	Condensate and Oil Production (MMbbl/yr)
AK	115	2,079	3,157	168
AZ	0	64	<1	<1
CO	2,017	47,756	1,642	95
ID	3	1	<1	0
MT	174	10,515	66	30
ND	2,623	12,706	464	395
NM	1,358	51,140	1,244	125
NV	2	73	<1	<1
OR	0	16	1	0
SD	7	244	15	2
UT	839	13,021	450	41
WA	0	0	0	0
WY	1,044	35,615	1,998	76
Total	8,182	173,230	9,038	932

2.0 METHODOLOGY

To develop the baseline 2014-2016 WESTAR-WRAP region emission inventory, first, base year 2014 emissions were compiled from existing emission inventory sources (described in Section 2.1). Subsequent to compilation of the base year 2014 emission inventory, outreach was conducted to gather additional data from regulatory agencies and upstream O&G operators to enhance the emissions inventory and, to the extent that data was provided, make the inventory applicable to the 2014-2016 baseline period (described in Section 2.2).

2.1 2014 WRAP OGWG Baseline O&G Emission Inventory version 1

Ramboll compiled a WESTAR-WRAP region 2014 base year O&G emission inventory version 1 (also referred to herein as the WRAP OGWG v1 emission inventory)¹¹ from the following emission inventories:

- 2014 Greater San Juan and Permian Basin Emission Inventory (Grant et al., 2018a)
- 2014 Intermountain West O&G Basin Emission Inventory (Parikh et al., 2017)
- Uinta Basin 2014 Air Agencies Oil and Gas Emissions Inventory (Utah Division of Air Quality [UDAQ], 2017)
- Colorado Department of Health and Environment (CDPHE) Denver Basin Emission Inventory (CDPHE, 2018)
- US Environmental Protection Agency (EPA) 2014 NEI O&G Inventory, version 2 (EPA, 2018)¹²

O&G emissions on tribal land in the above studies included nonpoint emissions which were based on tribe specific emissions only if they were provided directly by a tribe (e.g., Southern Ute Indian Tribe in Grant et al. [2018a]); otherwise, tribal nonpoint emissions were typically estimated by apportioning county-level emissions to tribal and non-tribal land based on O&G activity. For inventories that did not fully distinguish tribal from non-tribal sources, tribal and non-tribal splits were added by allocating emissions according to the fraction of O&G activity surrogates on and off tribal land in each county. Point source emissions on tribal lands consist of Part 71 sources and other minor sources (e.g., sources reported under the Tribal Minor New Source Rule) to the extent that each inventory included those emission sources.

Table 2-1 shows data sources by basin used to compile the version 1 emission inventory.

Table 2-1. Inventory data source by basin.

Basin	State	Reference
Greater San Juan	CO and NM	Grant et al. (2018a)
Permian	NM	Grant et al. (2018a)
Denver	CO	Parikh et al. (2017) and CDPHE (2018)
Uinta	UT	Parikh et al. (2017) and UDAQ (2017)
Piceance	CO	Parikh et al. (2017)
Paradox	CO	

¹¹ https://www.wrapair2.org/pdf/WESTAR_OGWG_Emissions_Inventory_2014_Webdistribution_081018.xlsx

¹² To extract emissions from the NEI, nonpoint emissions were extracted for all source classification (SCC) codes beginning with "2310". For point sources, O&G emissions were extracted for North American Industry Classification System (NAICS) codes: 2111, 4862, 21111, 48611, 48621, 211111, 211112, 213111, 213112, 486110, 486210.

Basin	State	Reference
Raton	CO	
Big Horn	WY and MT	
Powder River	WY and MT	
Green River	WY	
Central Western Overthrust	WY	
Wind River	WY	
Williston	MT, ND and SD	
Sweetgrass Arch	MT	
Central Montana Uplift	MT	
Other Basins	All	EPA (2018)

Emission inventory data gaps were filled to ensure completeness, to the extent feasible according to the following:

- PM_{2.5} emissions were not included in Grant et al. (2018a) and Parikh et al. (2017). PM_{2.5} emissions were assumed equivalent to PM₁₀ emissions taken from these reference sources.
- GHG emissions were not available in Parikh et al. (2017). GHG emissions were estimated by multiplying criteria air pollutant emissions for a given source category by a source category specific GHG to criteria air pollutant emissions mass ratio. For venting, fugitive, and tank sources, basin and well type specific GHG to VOC mass ratios available from the EPA O&G Tool were used. AP-42 process specific emission factors from the Greater San Juan and Permian Basin Inventory Study were used to estimate GHG to NO_x emission ratios for combustion sources.

2.2 Survey Updates for 2014-2016 baseline inventory

As part of technical improvements to the WESTAR-WRAP O&G emission inventory, a survey data collection effort was used to collect new information to enhance emission inventory accuracy. Survey data collection targeted specific equipment types, production areas, and operators that could substantially enhance the WESTAR-WRAP O&G emission inventory. First, the survey was distributed to state agencies so that in-house agency data could be leveraged prior to asking O&G operators to provide survey data. After state agencies filled out the survey, it was distributed to O&G operators to fill remaining data gaps.

In this section survey results are applicable to baseline emission inventory updates are reported and integration into the baseline year inventory (also referred to herein as the WRAP OGWG v2 emission inventory) is described.

2.2.1 Survey Content

Survey content was decided upon in collaboration with the WRAP OGWG and focused on gathering information on several key O&G emissions source categories. Two surveys were developed, one survey requesting a complete set of inputs for each source category, and a second survey focused only on emission controls practices and technology related inputs. Each

agency decided whether to distribute the survey to operators and if the operators would fill out the complete or controls-focused survey.

Table 2-2 shows the source categories and associated data requested in the survey. Several tabs in the survey request *representative* O&G equipment configuration and operation data. Survey respondents were instructed to provide *representative* data that, as accurately as feasible, reflects configuration(s) that represent a vast majority of activity in a given basin. The request for representative inputs is consistent with the estimation of upstream O&G emissions as nonpoint sources. Surveyed agencies and operators were also given the option to provide data files with individual configurations, in addition to, or in place of representative data. The O&G survey is available online: complete survey¹³ and controls-focused survey¹⁴.

Table 2-2. Survey Content

Source Category	Survey Data Fields
Upstream Exploration	
Drill Rigs	Spud type, well type, representative engine configuration (number, hours per spud, horsepower), engine age distribution, fleet turnover frequency
Hydraulic Fracturing Engines	Spud type, well type, representative engine configuration (number, hours per spud, horsepower), engine age distribution, fleet turnover frequency
Upstream Production	
Condensate Tanks	Spud type, VOC flashing emission rate, control type and prevalence, capture efficiency and basis, inspection type and frequency
Oil Tanks	Spud type, VOC flashing emission rate, control type and prevalence, capture efficiency and basis, inspection type and frequency
Wellhead Engines	Spud type, well type, number of engines per well by function (compressor, artificial lift, etc.), representative engine configuration (number, hours per spud, horsepower), engine age distribution
Gas Composition	
Produced Gas	Extended gas composition by spud type and/or well type.
Flash Gas Composition	Extended gas composition by spud type and/or well type

2.2.2 Survey Distribution and Collection

The survey was first provided to WRAP OGWG member state agencies. State agencies reviewed the survey and, if available, provided in-house agency data responses. State agencies determined whether they would distribute the survey to operators, and if so, whether to distribute the complete or controls-focused survey. Subsequently, the survey was distributed by agencies to select operators. Operators were responsible for contacting their drilling, hydraulic fracturing, etc. contractors to obtain relevant survey data.

¹³ https://www.wrapair2.org/pdf/WRAP_OGWG_Survey_SelectSrc_08Jan2019.xlsx

¹⁴ https://www.wrapair2.org/pdf/WRAP_OGWG_Survey_ControlsOnly_08Jan2019.xlsx

Survey distribution to operators, including supplemental outreach and operator activity data is described below.

1. Ramboll distributed the following materials to each WRAP OGWG state agency member:
 - a. Survey form
 - b. High priority operator list ranked by oil and gas (O&G) activity/ownership for each basin
 - c. Recommendations for survey collection and distribution
 - d. Survey cover letter template for agency survey distribution
2. Member state agency gathered survey data. Ramboll staff answered technical questions about the survey.
 - a. Each agency gathered survey data from internal agency sources and/or external sources such as O&G exploration and production companies.
 - b. If the agency chose to distribute the survey to O&G companies, the survey was distributed to the high priority operators chosen by the agency.
 - c. Each agency performed follow-up with operators the agency designated to fill out the survey to ensure that surveys were completed and submitted prior to the survey due date.

The type of survey distributed and the basins for which surveys were distributed is shown in Table 2-3.

Table 2-3. Operator survey distribution

State	Distributing Agency	Basin	Survey Type
Montana	MTDEQ	Big Horn	Complete
		Central Montana Uplift	Complete
		Powder River	Complete
		Sweetgrass Arch	Complete
		Williston	Complete
New Mexico	NMED	Permian	Complete
		San Juan	Complete
North Dakota	NDDOH	Williston	Complete
Wyoming	WYDEQ	Denver	Controls-focused
		Green River	Controls-focused
		Powder River	Controls-focused

2.2.3 Survey Collection

Several agencies provided data for specific O&G basins in response to the survey as indicated below.

- **Alaska** (Arctic Coastal Plains Province and Cook Inlet Basin): Baseline emission inventory updates.
- **Colorado** (Denver Basin): 2017 emission inventory. *Applicable to future year emission inventory controls.*

- **Montana** (Central Montana Uplift, Sweetgrass Arch, and Williston Basin): Gas compositions.
- **Wyoming** (Denver Basin, Green River Basin, and Powder River Basin): 2014 and 2017 detailed operator submissions to be used in the estimation of future year control factors. *Applicable to future year emission inventory controls.*
- **Utah** (Uinta Basin): Engine age distributions to be used in the estimation of future year control factors. *Applicable to future year emission inventory controls*

A total of 42 operators surveys were collected, with the largest number of surveys (17) collected in the Williston Basin in North Dakota (see Table 2-4). Operator survey results are documented below.

Table 2-4. Returned operator surveys.

State	Basin	No. of Returned Surveys	Percent of 2014 Basin-wide Activity Represented by Returned Surveys		
			Well Count	Oil Production	Gas Production
Montana	Big Horn	1	5%	0%	6%
	Central Montana Uplift	2	62%	5%	85%
	Powder River	1	23%	91%	90%
	Sweetgrass Arch	2	23%	19%	53%
	Williston	6	25%	64%	31%
New Mexico	Permian	4	66%	80%	86%
	San Juan	0	-	-	-
North Dakota	Williston	17	11%	25%	26%
Wyoming ^a	Denver	1	18%	46%	52%
	Green River	4	46%	51%	53%
	Powder River	4	4%	34%	13%

^a Control-focused survey, not applicable to baseline emission inventory improvements.

2.2.4 Operator Survey-Based Emission Inventory Updates

In this section operator survey results applicable to baseline emission inventory updates are reported and integration into the baseline year inventory is described. Table 2-5 shows, by basin, the categories for which operators submitted survey data. Emission inventory updates based on operator survey data are limited to the basins and source categories listed in Table 2-5.

Table 2-5. Categories for which survey data applicable to baseline inventory updates was submitted.

Source Category	Big Horn Basin	Central Montana Uplift	Sweetgrass Arch	Powder River Basin	Permian Basin	Williston Basin	
	MT	MT	MT	MT	NM	MT	ND
Drilling	-	-	-	-	x	x	x
Hydraulic Fracturing	-	-	-	-	x	x	x
Tanks	x	x	x	x	x	x	x
Wellhead Engines	x	x	x	x	x	x	x
Gas Compositions	x	x	x	x	x	x	x

For basins in which survey-based operator data was available for only one operator, if the operator represented greater than 10% of the O&G activity metric associated with a given source category, representative input factors were developed by assuming that the remaining O&G activity in the basin would have input factors equivalent to those used in the development of the WRAP OGWG v1 emission inventory. If the operator represented less than 10% of the O&G activity metric, a representative factor was not developed to preserve the confidentiality of a single operator's data.

2.2.4.1 Drill Rigs

Updated drill rig inputs were developed for the Permian Basin, Williston Basin in Montana, and Williston Basin in North Dakota (see Table A1). Rig activity per spud, estimated as total horsepower-hours (i.e., the product of number of engines, rated horsepower per engine, and hours per spud) decreased for each basin by 20%-53% relative to current inventory estimates. Permian Basin drill rigs were comprised of a substantial fraction of Tier 4 engines and Williston Basin drill rigs were comprised almost exclusively of Tier 2 engines. For operators that indicated use of Tier 4 engines, those engines were described as "generators". Therefore, Tier 4 drill rig engines were assumed to meet stringent generator-set emission standards. The baseline emission inventory was updated to be based on the drill rig configuration inputs in Table A1 for the indicated basins.

Table 2-6 shows the basis of drill rig emissions for basins in which survey-based input factors were developed. Survey-based emission rates per spud were developed based on survey-based factors in Table A1 and multiplied by the number of horizontal spuds in each county in applicable basins to estimate emissions. These emissions replaced estimates of drill rig emissions from horizontal spuds in the WRAP OGWG v1 emission inventory. County-level emissions were apportioned to non-tribal and tribal land according the fraction of spuds in each county on non-tribal and tribal land.

Table 2-6. Emission inventory basis for basins with drill rig survey data.

Basin	Horizontal ^b		Vertical	
	Non-tribal	Tribal	Non-tribal	Tribal
Permian	Survey-based factors	^a	OGWG v1	^a
Williston (MT)	Survey-based factors		OGWG v1	
Williston (ND)	Survey-based factors		OGWG v1	

^a not applicable, no tribal activity^b horizontal input factors were applied to directional wells**2.2.4.2 Hydraulic Fracturing Engines**

Updated hydraulic fracturing engine inputs were developed for the Permian Basin and Williston Basin in North Dakota (see Table A2). Fracturing engine activity per spud, estimated as total horsepower-hours (i.e., the product of number of engines, rated horsepower per engine, and hours per spud) increased substantially compared to current inventory estimates; Permian Basin total horsepower-hours increased by approximately 8 times and Williston Basin increased by approximately 27 times. Horsepower-hour increases are being driven by more intensive hydraulic fracturing activities at horizontal wells than assumed for previous inventories. Emission rates also changed substantially from previous estimates, with substantial use of Tier 4 engines in both the Williston and Basin Permian Basin and use of both natural gas turbine and electrified engine configurations in addition to diesel engine configurations in the Permian Basin. Based on input from several operators, hydraulic fracturing pump arrays that use Tier 4 diesel engines are configured to use generator-sets. Therefore, Tier 4 engines in hydraulic fracturing pump arrays were assumed to meet stringent Tier 4 generator-set standards. Other, less prevalent engines with smaller rated-power per engine such as light plants or blenders were assumed to meet Tier 4 interim standards.

Table 2-7 shows the basis of hydraulic fracturing engine emissions for basins in which survey-based input factors were developed. Survey-based emission rates per fracturing event were developed based on survey-based factors in Table A2 and multiplied by the number of horizontal spuds in each county in applicable basins to estimate emissions; one hydraulic fracturing event was assumed per spud. These emissions replaced estimates of hydraulic fracturing engine emissions from horizontal wells in the WRAP OGWG v1 emission inventory. County-level emissions were apportioned to non-tribal and tribal land according the fraction of spuds in each county on non-tribal and tribal land.

Table 2-7. Emission inventory basis for basins with hydraulic fracturing engine survey data.

Basin	Horizontal ^b		Vertical	
	Non-tribal	Tribal	Non-tribal	Tribal
Permian	Survey-based factors	^a	OGWG v1	^a
Williston (ND & MT)	Survey-based factors		OGWG v1	

^a not applicable, no tribal activity^b horizontal input factors were applied to directional wells

2.2.4.3 Tanks

Oil Tanks

Updated oil tank inputs were developed for several O&G basins (see Table A3). There are substantial differences in oil tank input factors compared to input factors in the current inventory. For example, the fraction of uncontrolled tanks changed from 73% to 19% for the Permian Basin, from 14% to 1% for the Powder River Basin, from 17% to < 1% for horizontal and vertical wells in the Williston Basin. Decreases in the prevalence of uncontrolled tanks indicates that a higher fraction of tanks are being controlled to comply with regulations such as EPA New Source Performance Standard (NSPS) Subpart OOOO. Uncontrolled VOC flash emission factors decreased for several basins. For example, uncontrolled VOC flash emission factors decreased by 16% and 61% for oil tanks in the Williston Basin, in Montana and North Dakota, respectively. Flash emission factor decreases may result from factors such as better sampling and/or the use of more site specific information in E&P Tank model runs and/or process simulation software in the submitted surveys compared to previously compiled emission inventory inputs.

Table 2-8 shows the basis of oil tank emissions for basins in which survey-based input factors were developed. Survey-based emission rates per barrel of oil produced were developed based on survey-based factors in Table A3 and multiplied by the amount oil production from horizontal or vertical wells in each county in applicable basins to estimate emissions. These emissions replaced estimates of oil tank emissions from horizontal wells and vertical wells in the WRAP OGWG v1 emission inventory. County-level emissions were apportioned to non-tribal and tribal land according the fraction of oil production in each county from wells on non-tribal and tribal land.

Table 2-8. Emission inventory basis for basins with oil tank survey data.

Basin	Horizontal ^b		Vertical	
	Non-tribal	Tribal	Non-tribal	Tribal
Central Montana Uplift	OGWG v1		Survey-based factors	
Permian	Survey-based factors	^a	OGWG v1	^a
Powder River (MT)	OGWG v1		Survey-based factors	
Sweetgrass Arch	OGWG v1		Survey-based factors	
Williston (MT)	Survey-based factors			
Williston (ND)	Survey-based factors			

^a not applicable, no tribal activity

^b horizontal input factors were applied to directional wells

Condensate Tanks

Updated condensate tank inputs were developed for the Sweetgrass Arch and Williston Basin in North Dakota and Montana (see Table A4). The fraction of uncontrolled tanks increased from 31% to 100% in the Sweetgrass Arch Basin and decreased from 8% to 4% and 8% to 1% in the Williston Basin, in Montana and North Dakota, respectively.

Table 2-9 shows the basis of condensate tank emissions for basins in which survey-based input factors were developed. Survey-based emission rates per barrel of condensate produced were developed based on survey-based factors in Table A4 and multiplied by the amount oil production from horizontal or vertical wells in each county in applicable basins to estimate emissions. These emissions replaced estimates of condensate tank emissions from horizontal wells and vertical wells in the WRAP OGWG v1 emission inventory. County-level emissions were apportioned to non-tribal and tribal land according to the fraction of condensate production in each county from wells on non-tribal and tribal land.

Table 2-9. Emission inventory basis for basins with condensate tank survey data.

Basin	Horizontal ^b		Vertical	
	Non-tribal	Tribal	Non-tribal	Tribal
Sweetgrass Arch	OGWG v1		Survey-based factors	
Williston (MT)	Survey-based factors		OGWG v1	
Williston (ND)	Survey-based factors		OGWG v1	

^a not applicable, no tribal activity

^b horizontal input factors were applied to directional wells

Capture Efficiency

For tanks with emission controls, capture efficiency represents the percent of uncontrolled emissions that are controlled by the control device. Open thief hatches result in uncontrolled fugitive tank emissions. Across all returned operator surveys, 20 condensate tank configurations and 51 oil tank configurations were submitted. 75% of condensate tank configuration and 57% of oil tank configuration responses included a response to the thief hatch status (summarized in Table 2-10). The overall average percent of thief hatches open was 2.8% for condensate tanks and 3.0% for oil tanks.

Table 2-10. Open thief hatch survey response summary.

Operator Response	Survey Field: Percentage of Tanks Observed with Thief Hatches Open	Average Percentage of Tanks Observed with Thief Hatches Open
	Number of Responses	
Condensate Tanks		
No Response / Not available	5	2.8%
Zero	7	
Minimal	3	
Non-zero Value	5	
Oil Tanks		
No Response / Not tracked	29	3.0%
Zero	9	
Minimal	1	
Non-zero Value	12	

Assuming that a tank with an open thief hatch emits VOCs at the uncontrolled tank VOC emission rate, a capture efficiency of 97% (i.e., 3% of tank emissions are not routed to the flare) would result in emissions that are 2.5 times higher for a 98% efficient control device and 1.6 times higher for 95% efficient control device (see Figure 2-1).

More study is needed to (1) develop robust capture efficiency estimates and (2) estimate VOC emission magnitude when a thief hatch is open; the increases in emissions estimated in Figure 2-1 are screening level estimates.

At this time, sufficient information is not available to extrapolate the average capture efficiency shown in Table 2-10 across the WESTAR-WRAP region. Variation in capture efficiency by production type and geography is not available. Therefore, capture efficiency is assumed to be 100%, consistent with previous inventories.

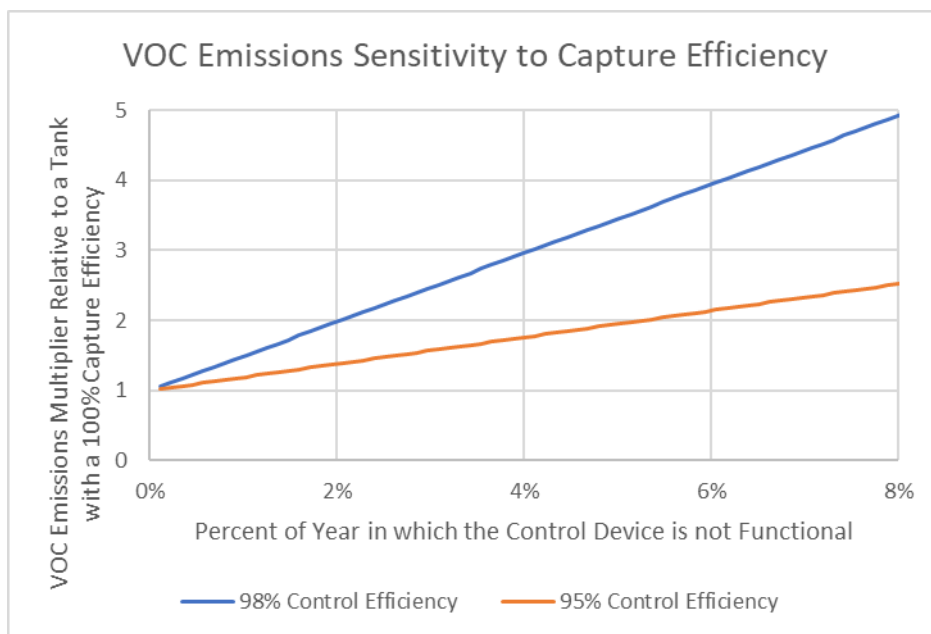


Figure 2-1. Tank VOC emissions sensitivity to capture efficiency.

2.2.4.4 Wellhead Engines

Updated wellhead configurations were developed for the basin and engine types listed below and are included in Table A5.

- **Sweetgrass Arch Wellhead Compressors Engines:** WRAP OGWG v1 input factors indicated zero activity from this source category. Operator submitted survey data indicated substantial use of wellhead compressors in this basin.
- **Bighorn Basin Lateral Compressor Engines:** Survey-based input factors are similar to WRAP OGWG v1 input factors.
- **Central Montana Uplift Lateral Compressor Engines:** Survey-based input factors include lower annual activity and higher prevalence compared to WRAP OGWG v1 input factors.

- **Williston Basin Artificial Lift Engines:** Survey-based input factors were developed by horizontal and vertical spud types for Montana and North Dakota. For each spud type and state, the survey-based input factors showed substantially higher electrification compared to the WRAP OGWG v1 input factors.
- **Permian Basin Artificial Lift Engines:** Survey-based input factors were developed by horizontal spud type for New Mexico. Survey-based input factors showed lower prevalence and electrification and higher average engine rated-power compared to the WRAP OGWG v1 input factors.
- **Williston Basin Generators:** Survey-based input factors were developed for generators operating at horizontal oil wells. Wellhead generators were not included in the WRAP OGWG v1 emission inventory. 11% of horizontal oil wells are estimated to have a generator.

Table 2-11 shows the basis of wellhead engine emissions for basins in which survey-based input factors were developed. Survey-based emission rates per active well were developed based on survey-based factors in Table A5 and multiplied by the number of active horizontal oil, horizontal gas, vertical oil, or vertical gas wells in each county in applicable basins to estimate emissions. These emissions replaced estimates of wellhead engine emissions in the WRAP OGWG v1 emission inventory. County-level emissions were apportioned to non-tribal and tribal land according the fraction of active wells in each county from wells on non-tribal and tribal land.

Table 2-11. Emission inventory basis for basins with wellhead engine survey data.

Basin	Engine Type	Well Type	Horizontal ^b		Vertical	
			Non-tribal	Tribal	Non-tribal	Tribal
Sweetgrass Arch	Wellhead Compressors	Gas	OGWG v1		Survey-based factors	
Bighorn Basin	Lateral Compressor	Gas	OGWG v1		Survey-based factors	
Central Montana Uplift	Lateral Compressor	Gas	OGWG v1		Survey-based factors	
Williston Basin (ND & MT)	Artificial Lift	Oil	Survey-based factors			
Permian Basin	Artificial Lift	Oil	Survey-based factors		OGWG v1	
Williston Basin (ND & MT)	Generators	Oil	Survey-based factors		c	

^a not applicable, no tribal activity

^b horizontal input factors were applied to directional wells

^c not applicable, generator engine inputs are not available for vertical wells in the survey or WRAP OGWG v1. No emissions are estimated for this engine type at vertical wells.

2.2.4.5 Emission Changes Resulting from Integration of Operator Survey Data

NOx emissions increased by 8% over the WESTAR-WRAP region based on integration of operator survey data into the inventory (see Table 2-12). Hydraulic fracturing engine emissions accounted for 47% of NOx emission increases. Operator surveys indicated the use of pump engine arrays with more engines and more operational hours than previous inventories. Emissions from artificial lift engines accounted for 38% of NOx emissions increases. Operator surveys indicated the use of artificial life engines with higher rated power than assumed in previous inventories. Emissions from drill rig emissions accounted for close to 100% of NOx emission decreases as a result of lower overall combined activity in horsepower-hours relative to previous inventories.

Table 2-12. NOx Emission Changes Resulting from Integration of Operator Survey Data.

Basin	Source Category	NOx (tpy)
Williston , ND	Hydraulic Fracturing Engines	18,369
Williston , ND	Artificial Lift Engines	11,894
Williston , ND	Generator Engines	2,848
Permian , NM	Artificial Lift Engines	2,800
Sweetgrass , MT	Nonpoint Compressor Engines	1,789
Williston , MT	Artificial Lift Engines	1,404
Williston , ND	Oil Tanks	823
Williston , MT	Hydraulic Fracturing Engines	743
Permian , NM	Hydraulic Fracturing Engines	742
Williston , MT	Generator Engines	437
Central Montana Uplift , MT	Nonpoint Compressor Engines	226
Permian , NM	Oil Tank Flaring	54
Williston , ND	Condensate Tanks	17
Big Horn , MT	Nonpoint Compressor Engines	9
Williston , MT	Condensate Tanks	1
Williston , ND	Drill Rigs	-15,610
Williston , MT	Drill Rigs	-1,258
Permian , NM	Drill Rigs	-943
Williston , MT	Oil Tanks	-18
Powder River , MT	Oil Tanks	-1
Sweetgrass , MT	Oil Tanks	0
Central Montana Uplift , MT	Oil Tanks	0
Sweetgrass , MT	Condensate Tanks	0
Total Change		24,325
Percent Change		8%

VOC emissions decreased by 22% over the WESTAR-WRAP region based on integration of operator survey data into the inventory (see Table 2-13). VOC emission increases were small compared to VOC emission decreases. Emissions from oil tanks accounted for close to 100% of VOC emission decreases as a results of higher emission control prevalence.

Table 2-13. VOC Emission Changes Resulting from Integration of Operator Survey Data.

Basin	Source Category	VOC (tpy)
Permian , NM	Artificial Lift Engines	2,224
Williston , ND	Hydraulic Fracturing Engines	1,450
Williston , ND	Artificial Lift Engines	957
Sweetgrass , MT	Oil Tanks	535
Williston , ND	Condensate Tanks	485
Williston , ND	Generator Engines	417
Permian , NM	Drill Rigs	325
Permian , NM	Hydraulic Fracturing Engines	175
Williston , MT	Artificial Lift Engines	139
Central Montana Uplift , MT	Oil Tanks	104
Williston , MT	Generator Engines	64
Williston , MT	Hydraulic Fracturing Engines	58
Sweetgrass , MT	Nonpoint Compressor Engines	33
Sweetgrass , MT	Condensate Tanks	32
Williston , MT	Condensate Tanks	20
Powder River , MT	Oil Tanks	5
Big Horn , MT	Nonpoint Compressor Engines	0
Williston , ND	Oil Tanks	-282,784
Permian , NM	Oil Tank	-28,623
Williston , MT	Oil Tanks	-16,190
Williston , ND	Drill Rigs	-1,033
Williston , MT	Drill Rigs	-81
Central Montana Uplift , MT	Nonpoint Compressor Engines	-2
Total Change		-321,690
Percent Change		-22%

2.2.5 Agency Survey-Based Emission Inventory Updates

The 2014 NEI v2 was the sole basis of Alaska O&G emissions in the WRAP OGWG v1 emission inventory. Alaska Department of Environmental Conservation (ADEC) noted that emissions from several facilities emitting below Title V thresholds were not included in the 2014 NEI v2. ADEC provided emissions for these sources (see Table 2-14) were added to the WRAP OGWG v2 emission inventory.

Table 2-14. Alaska O&G emissions from small nonpoint sources.

Facility	Emissions (tons/year)					
	NO _x	VOC	CO	SO ₂	PM ₁₀	PM _{2.5}
Greater Prudhoe Bay Skid 50 Pad Transfer Station	39	^a	^a	39	^a	^a
Peak Base Shop, Peak Wellex, and Nabors Base Camp Facilities	56	18	44	5.3	11	^a
Milne Point S Pad (CHOPS)	37	<1	14	11	<1	^a
Alpine Satellite Drill Pad CD5	93	88	60	23	5	^a
Arctic Wolf Camp	39	^a	^a	^a	^a	^a
24 Man Skid Camp	41	^a	^a	^a	^a	^a
Mustang Oil Field Development	186	110	216	9	7	7
Paxton Production Facility	57	29	50	<1	1	1
Gudenrath Compressor Station	76	<1	26	1	2	2
Baker Platform	88	10	28	11	6	^a
NNA Grind and Inject Operation	86	^a	^a	^a	^a	^a
Kenai Gas Field Pad 41-18	42	^a	44	53	^a	^a
Cook Inlet Exploratory Drilling Program- Bluecrest / Buccaneer	17	8	49	5	4	^a
Cosmopolitan Project - Bluecrest	64	62	94	35	12	^a
Cosmopolitan Project - Buccaneer	21	25	59	12	4	^a

^a Emissions not included in reference dataset and were set to zero in WRAP OGWG v2 inventory

3.0 SUMMARY RESULTS

O&G emissions results for the baseline 2014-2016 WRAP OGWG v2 emission inventory for the WESTAR-WRAP region are presented below as a series of tables and charts. Additional summaries and fully detailed emission inventory data are available in spreadsheets that accompany this report which are posted on the WRAP OGWG website (<https://www.wrapair2.org/OGWG.aspx>).

3.1 2014-2016 WRAP OGWG v2 emission inventory

2014-2016 WRAP OGWG v2 NO_x and VOC emissions for all WRAP region basins are summarized in Table 3-1 and Table 3-2 respectively. Across the WESTAR-WRAP region, most nonpoint O&G emissions are emitted from wellsite sources and point O&G emission are emitted from midstream sources. Approximately 58% of 2014 NO_x emissions and over 85% of 2014 VOC emissions were from nonpoint sources. Basin specific nonpoint and point source contributions result from basin specific equipment and operational characteristics and infrastructure, and in some cases basin specific accounting. For example, the Uinta Basin includes several wellsite source categories in the point source emission inventory. The top-seven emitting bases account for approximately 75% of NO_x emissions and the top-five basin and state combinations account for over 80% of VOC emissions.

Table 3-1. Summary of nonpoint and point NO_x emissions (tons/yr) by basin.

Basin and State	NO _x Emissions (tons/yr)		
	Nonpoint	Point	Total
Williston, ND	55,003	2,703	57,706
San Juan, NM	33,436	11,294	44,730
Arctic Coastal Plains Province, AK	1,384	34,348	35,732
Permian, NM	14,442	18,561	33,004
Powder River, WY	24,508	5,017	29,525
Denver, CO	16,750	8,155	24,905
Piceance, CO	5,824	9,571	15,395
San Juan, CO	11,842	3,417	15,259
Uinta, UT	886	14,161	15,047
Green River, WY	5,430	5,408	10,838
Raton, CO	79	6,881	6,959
AK Cook Inlet Basin, AK	1,853	4,664	6,517
Williston, MT	4,930	482	5,412
Big Horn, WY	972	1,501	2,473
Sweetgrass Arch, MT	2,128	313	2,441
Denver Basin noCO, WY	1,733	33	1,766
Las Animas Arch, CO	420	1,252	1,671
Wind River, WY	235	1,334	1,569
Plateau Sedimentary Prov, AZ	-	1,468	1,468
Paradox, UT	923	300	1,123
Other WRAP Basins	1,218	7,474	8,692
Total	183,995	138,337	322,333

Table 3-2. Summary of nonpoint and point VOC emissions (tons/yr) by Basin.

Basin and State	VOC Emissions (tons/yr)		
	Nonpoint	Point	Total
Williston, ND	196,696	962	197,658
Powder River, WY	172,453	4,658	177,112
Denver, CO	159,112	6,704	165,817
Permian, NM	86,633	11,164	97,796
Uinta, UT	9,212	85,077	94,290
San Juan, NM	79,743	6,824	86,567
Green River, WY	62,626	11,306	73,932
Williston, MT	26,977	705	27,682
Arctic Coastal Plains Province, AK	21,278	672	21,949
Paradox, UT	17,422	48	17,471
Piceance, CO	3,114	11,620	14,734
Wind River, WY	6,601	1,424	8,025
Sweetgrass Arch, MT	5,277	103	5,380
AK Cook Inlet Basin, AK	4,712	650	5,362
Big Horn, WY	3,523	513	4,036
San Juan, CO	2,176	1,701	3,877
Other WRAP Basins	9,763	4,659	14,421
Total	867,318	148,791	1,016,110

Figure 3-1 and Figure 3-2 show NO_x and VOC nonpoint emissions contributions, respectively, for basin and state combinations with the largest nonpoint emission contributions.

The largest source of nonpoint NO_x emissions are hydraulic fracturing engines, wellhead engines, process heaters, and drill rigs. Wellhead engines (including artificial lift engines, wellhead and lateral compressor engines, generators and other miscellaneous engines) are the largest contributor to nonpoint NO_x emissions in the San Juan Basin (NM; 90%), San Juan Basin (CO; 95%), and Permian Basin (NM; 52%). Hydraulic fracturing engines are the largest contributor to NO_x emissions for the Williston Basin (ND; 43%) and Powder River Basin (WY; 81%). Drill rigs are the largest contributor to NO_x emissions for the Denver Basin (CO; 32%) and Piceance Basin (CO; 40%).

The largest nonpoint VOC emissions sources vary by basin. In the Williston Basin (ND), casinghead gas accounts for 50% of VOC emissions. In the Powder River Basin (WY), hydraulic fracturing and completion activities account for 91% of VOC emissions. In the Denver Basin (CO), condensate tanks account for 76% of VOC emissions. In the Permian Basin (NM), oil tanks account for 45% of VOC emissions. In the San Juan Basin (NM), pneumatic devices account for 32% of VOC emissions.

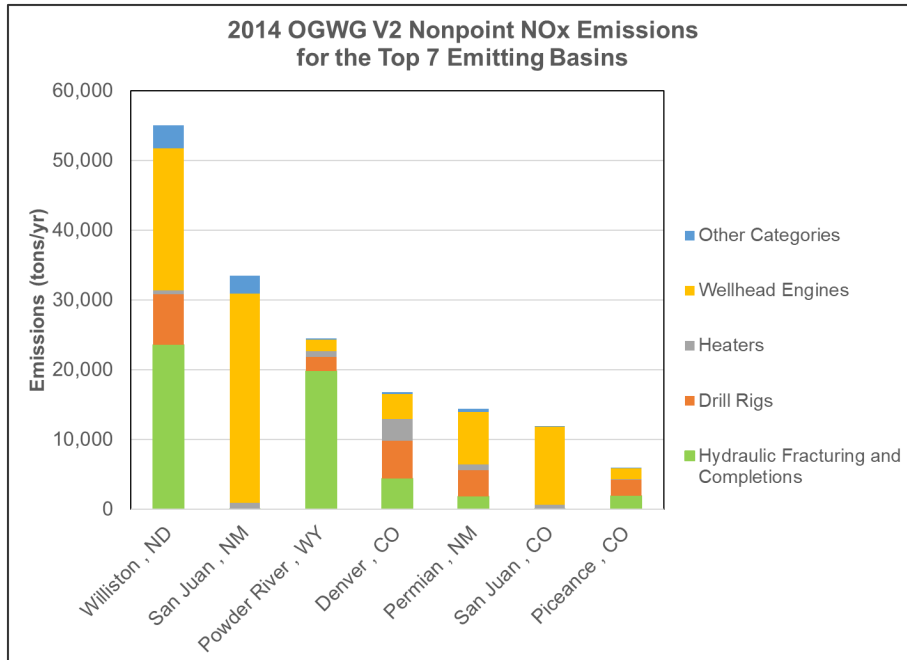


Figure 3-1. 2014 OGWG V2 nonpoint NOx emissions (tons/yr) contribution by source category for top 7 highest emitting basins.

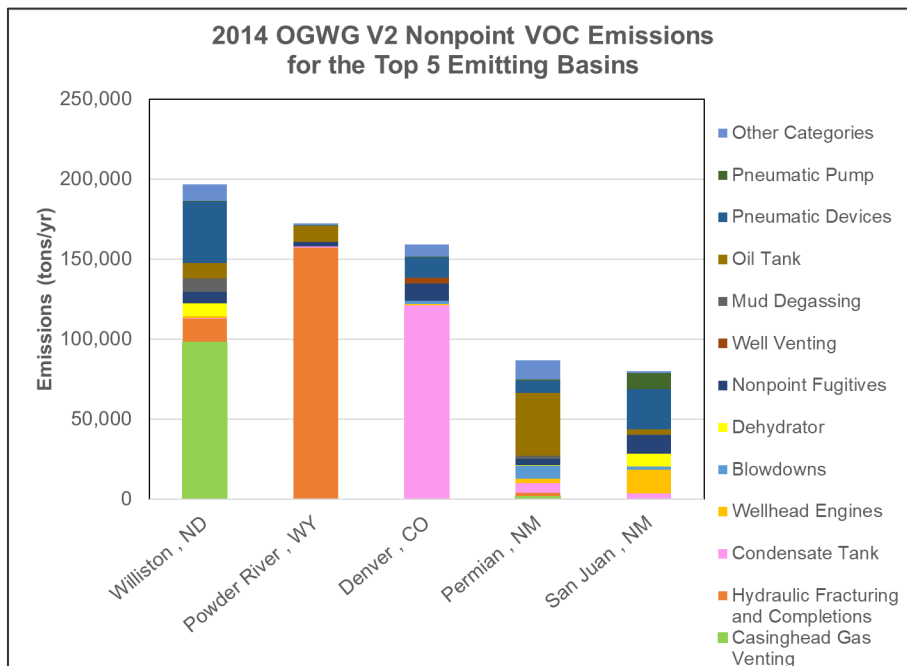


Figure 3-2. 2014 OGWG V2 nonpoint VOC emissions (tons/yr) contribution by source category for top 5 highest emitting basins.

3.1.1 2014-2016 Baseline Comparison to 2014 Emission Inventories

Changes from the 2014 NEI v2 to the 2014 base year WRAP OGWG v1 to the 2014-2016 baseline WRAP OGWG v2 are shown below for NO_x (Figure 3-3) and VOC (Figure 3-4).

Changes from 2014 NEI v2 to the WRAP OGWG v1 inventory are based on state supplied emission inventory updates (e.g., Colorado condensate tanks and Uinta Basin 2014 Air Agencies Oil and Gas Emissions Inventory); differences between NEI v2 emissions and the 2014 IWDW emission inventory that was the basis of WRAP OGWG v1 emission inventory for several states (e.g., Wyoming, Colorado); and for the Greater San Juan (Colorado and New Mexico) and Permian Basin (New Mexico), differences between Grant et al. (2018a) and the EPA NEI v2. WESTAR-WRAP region-wide emission increased by 16% for NO_x and 14% for VOC from 2014 NEI v2 to 2014 base year WRAP OGWG v2.

Changes from the WRAP OGWG v1 to the WRAP OGWG v2 emission inventory are based on updates per agency and operator survey responses. WESTAR-WRAP region-wide NO_x emissions increased by 9% and VOC decreased by 22%. NO_x emission increases for North Dakota, Montana, and New Mexico resulting from survey-based updates were the primary cause of WESTAR-WRAP region-wide NO_x emission increases. VOC emission decreases for North Dakota, Montana, and New Mexico resulting from survey-based updates were the primary cause of WESTAR-WRAP region-wide VOC emission decreases.

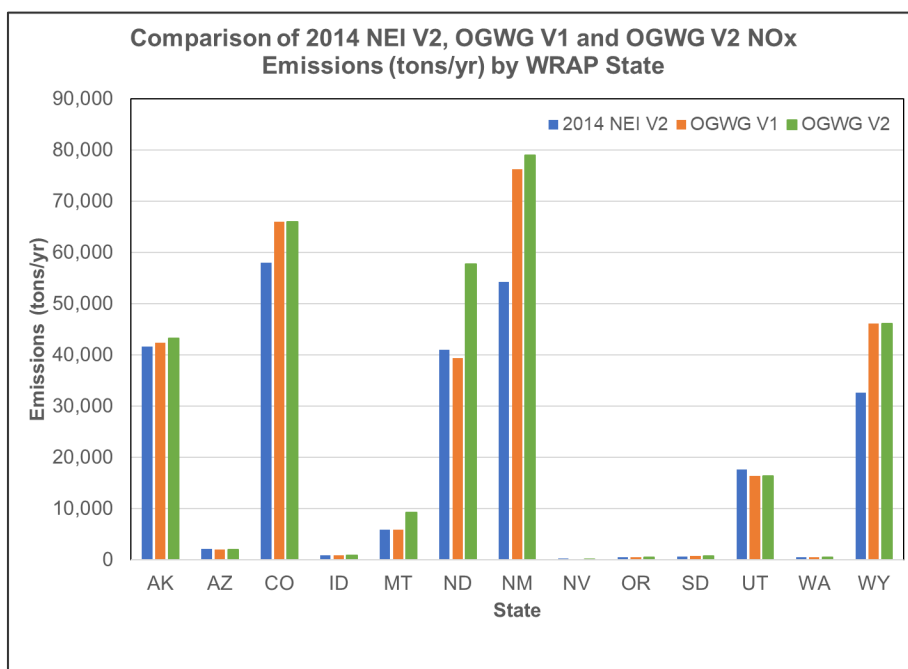


Figure 3-3. Comparison of 2014 NEI, OGWG V1 and OGWG V2 NO_x emissions by WRAP region State.

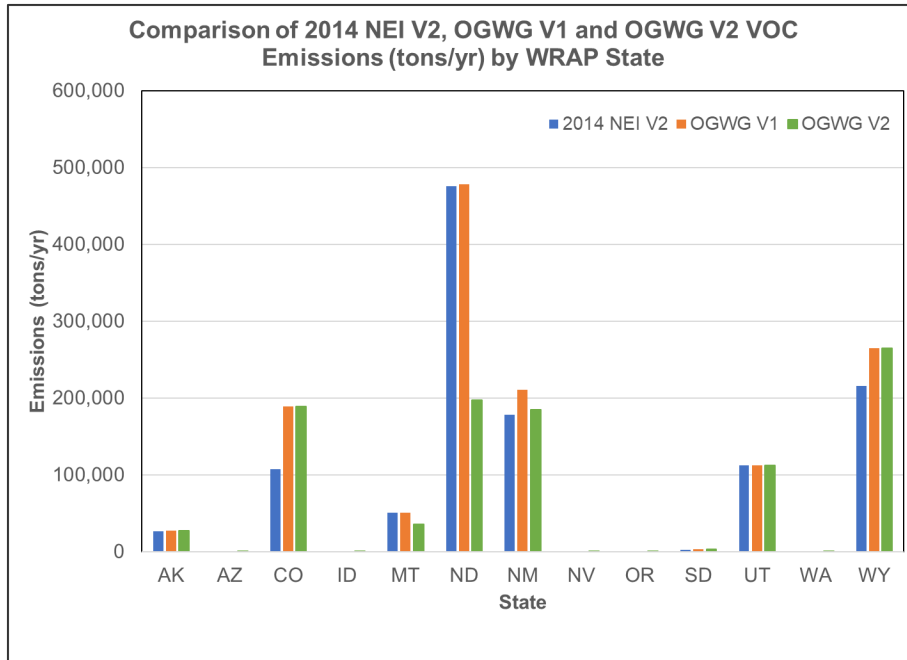


Figure 3-4. Comparison of 2014 NEI, OGWG V1 and OGWG V2 VOC emissions by WRAP region State.

3.1.2 2008, 2011, 2014-2016 baseline summaries

Figure 3-5 and Figure 3-6 show emission trends for WESTAR-WRAP basins which were included in the WestJUMP AQMS ¹⁵ and/or WAQS ¹⁶. The geographical extent of each basin is not always the same across these inventories, however, core O&G activity counties in each basin generally did not change across inventories.

Substantial NOx emission increases from the 2008 to 2014-2016 inventory are noted for several basins, although emission increases appear to be moderated for several basins by lower emissions per unit of production based on regulatory controls and/or infrastructure configurations. Denver Basin NOx emission increases of 20% and VOC increases of 66% from 2008 to 2014-2016 are substantially less than the Colorado-wide 287% oil production increase from 2008 to 2016. Permian Basin NOx emission increases of 34% and VOC decreases of 24% from 2008 to 2014-2016 are substantially less than the New Mexico-wide 143% oil production increase from 2008 to 2016. Williston Basin NOx emission increases of 117% and VOC decreases of 23% from 2011 to 2014-2016 are less than the North Dakota-wide oil production increases of 148% from 2011 to 2016. Increases in San Juan Basin NOx (25%) and VOC (60%) emissions from 2011 to 2014-2016 are due primarily to updated emission inventory inputs and methodology in the 2014 Greater San Juan Basin emission inventory study (Grant et al. [2018a]). Changes in Uinta Basin emissions are expected to result from both oil and gas production changes and changes to emission inventory compilation methodology in the most recent Utah Agencies Uinta Basin emission inventory.

¹⁵ <https://www.wrapair2.org/westjumpaqms.aspx>

¹⁶ <http://views.cira.colostate.edu/wiki/#WAQS>

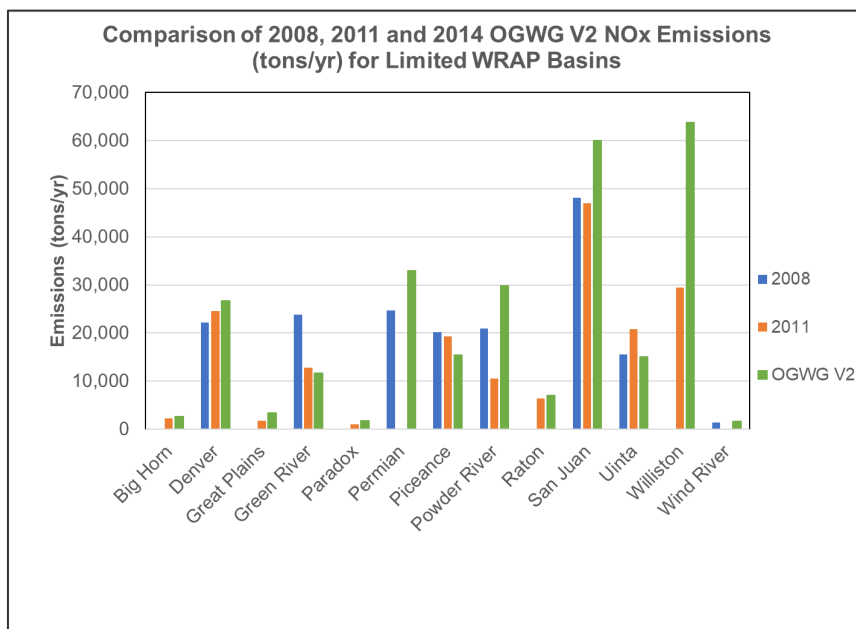


Figure 3-5. Comparison of 2008, 2011 and 2014 OGWG V2 NOx emissions (tons/yr) for limited WRAP Basins^{17,18,19}.

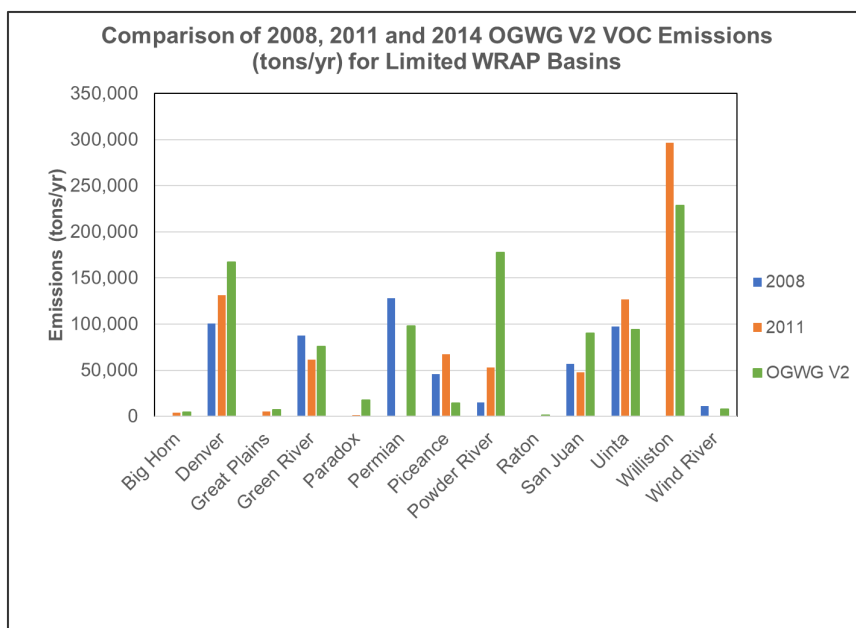


Figure 3-6. Comparison of 2008, 2011 and 2014 OGWG V2 VOC emissions (tons/yr) for limited WRAP Basins^{17,18,19}.

¹⁷ Emissions for some basins are not available for 2008 or 2011.

¹⁸ Paradox and Raton 2011 emissions are limited to permitted sources.

¹⁹ Great Plains includes emissions for Sweetgrass arch and Central Montana Uplift basins.

4.0 REFERENCES

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Appendix A
**Survey-based Input Factors Updates for the Baseline Emission
Inventory**

Table A1. Baseline Emission Inventory Inputs: Drill Rigs.

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Permian Basin (NM)		
Fraction of Spuds Represented	21%	not applicable
Spud Type	Horizontal	Horizontal
Well Type	Oil	Oil
Fuel Type	Diesel	Diesel
Number of Engine Per Rig (number/rig)	5	8
Rated Horsepower (hp/engine)	1477	825
Hours of Operation (hours/spud)	546	768
Percent of Engines Electrified (%)	0%	25%
Percent of Engines - Uncontrolled	0%	EPA 2014a MOVES Defaults
Percent of Engines - Tier 1	0%	
Percent of Engines - Tier 2	21%	
Percent of Engines - Tier 3	0%	
Percent of Engines - Tier 4	79%	
Average Engine Turnover Frequency (years)	^a	
Williston Basin (MT)		
Fraction of Spuds Represented	43%	not applicable
Spud Type	Horizontal	Horizontal
Well Type	Oil	Oil
Fuel Type	Diesel	Diesel
Number of Engine Per Rig (number/rig)	2	2
Rated Horsepower (hp/engine)	2193	2293
Hours of Operation (hours/spud)	236	481
Percent of Engines Electrified (%)	0%	0%
Percent of Engines - Uncontrolled	0%	Emission factors indicated a mix of engines up to Tier 4 certification
Percent of Engines - Tier 1	0%	
Percent of Engines - Tier 2	100%	
Percent of Engines - Tier 3	0%	
Percent of Engines - Tier 4	0%	
Average Engine Turnover Frequency (years)	^a	
Williston Basin (ND)		
Fraction of Spuds Represented	47%	not applicable
Spud Type	Horizontal	Horizontal
Well Type	Oil	Oil
Fuel Type	Diesel	Diesel

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Number of Engine Per Rig (number/rig)	4	2
Rated Horsepower (hp/engine)	1445	2206
Hours of Operation (hours/spud)	259	507
Percent of Engines Electrified (%)	23%	0%
Percent of Engines - Uncontrolled	0%	Emission factors indicated a mix of engines up to Tier 4 certification
Percent of Engines - Tier 1	0%	
Percent of Engines - Tier 2	99%	
Percent of Engines - Tier 3	1%	
Percent of Engines - Tier 4	0%	
Average Engine Turnover Frequency (years)	5	

^a Not enough information is available to populate this field

Table A2. Baseline Emission Inventory Inputs: Hydraulic Fracturing Engines.

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Permian Basin (NM)		
Fraction of Spuds Represented	19%	not applicable
Spud Type	Horizontal	All
Well Type	Oil	All
Configuration Type	Diesel Engine	Diesel Engine
Fraction of ICE Engine Configurations	95%	100%
Number of Engines Per Frac Job (number/frac)	22	10
Rated Horsepower (hp/engine)	1697	2313
Hours of Operation (hours/frac job)	109	23
Percent of Engines Electrified (%)	5%	0%
Percent of Engines - Uncontrolled	0%	EPA 2014a MOVES Defaults
Percent of Engines - Tier 1	0%	
Percent of Engines - Tier 2	11%	
Percent of Engines - Tier 3	0%	
Percent of Engines - Tier 4	84%	
Average Engine Turnover Frequency (years)	4	
Configuration Type	Turbine	Turbine

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Fraction of Natural Gas Engine Configurations	5%	0%
Rated Horsepower (hp/turbine)	49,000	-
Hours of Operation (hours/frac job)	70	-
Percent of Turbines - Uncontrolled	100%	-
Average Engine Turnover Frequency (years)	10	-
Williston Basin (ND)		
Fraction of Spuds Represented	39%	not applicable
Spud Type	Horizontal	All
Well Type	Oil	All
Fuel Type	Diesel	Diesel
Number of Engines Per Frac Job (number/frac)	29	5
Rated Horsepower (hp/engine)	1356	1823
Hours of Operation (hours/frac job)	156	26
Percent of Engines Electrified (%)	0%	0%
Percent of Engines - Uncontrolled	0%	Emission factors indicated a mix of engines up to Tier 4 certification
Percent of Engines - Tier 1	5%	
Percent of Engines - Tier 2	35%	
Percent of Engines - Tier 3	3%	
Percent of Engines - Tier 4	56%	
Average Engine Turnover Frequency (years)	3	
Powder River Basin (MT)		
<i>Survey response was limited to one operator, comprising a very small fraction of activity, therefore, no input factors were developed.</i>		
Williston Basin (MT)		
<i>Survey response was limited to two operators comprising 2% of exploration activity. Recommend assuming that Willison Basin, Montana hydraulic fracturing inputs are equivalent to Williston Basin, North Dakota.</i>		

^a Not enough information is available to populate this field

Table A3. Baseline Emission Inventory Inputs: Oil Tanks.

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Central Montana Uplift (MT)		
Fraction of Oil Production Represented	8%	not applicable
Spud Type	Vertical	All

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Tank Type	Oil Tank	Oil Tank
Gas Venting Rate (MCF/bbl)	0.01	0.01
Uncontrolled Flash VOC EF (lb VOC/bbl)	1.40	1.75
Percent of Tanks - Uncontrolled	100%	47%
Percent of Tanks - Flares	0%	53%
Percent of Tanks - Vapor Recovery Unit (VRU)	0%	0%
Percent of Tanks - Other Device	0%	0%
Other Device Control Type Description	-	-
Inspection Type	Visual	a
Frequency of Inspection (number/tank/year)	189	
Percent of Tanks - Open Thief Hatch	3%	
Percent of Tanks - Open Dump Valves	0%	
Annual Average Hours Controls are Offline - Maintenance	a	
Annual Average Hours Controls are Offline - Other		
Other - Description		
Permian (NM)		
Fraction of Oil Production Represented	3%	not applicable
Spud Type	Horizontal	All
Tank Type	Oil Tank	Oil Tank
Gas Venting Rate (MCF/bbl)	0.03	0.01
Uncontrolled Flash VOC EF (lb VOC/bbl)	1.93	1.60
Percent of Tanks - Uncontrolled	19%	73%
Percent of Tanks - Flares	47%	27%
Percent of Tanks - Vapor Recovery Unit (VRU)	1%	0%
Percent of Tanks - Other Device	33%	0%
Other Device Control Type Description	Combustor	-
Inspection Type	LDAR/OGI/IR Camera	a
Frequency of Inspection (number/tank/year)	32	
Percent of Tanks - Open Thief Hatch	0%	
Percent of Tanks - Open Dump Valves	0%	
Annual Average Hours Controls are Offline - Maintenance	36	
Annual Average Hours Controls are Offline - Other	0	

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Other - Description	-	
Powder River Basin (MT)		
Fraction of Oil Production Represented	93%	not applicable
Spud Type	vertical	All
Tank Type	Oil Tank	Oil Tank
Gas Venting Rate (MCF/bbl)	0.02	0.04
Uncontrolled Flash VOC EF (lb VOC/bbl)	1.88	2.84
Percent of Tanks - Uncontrolled	1%	14%
Percent of Tanks - Flares	6%	86%
Percent of Tanks - Vapor Recovery Unit (VRU)	93%	0%
Percent of Tanks - Other Device	0%	0%
Other Device Control Type Description	-	-
Inspection Type	Routine	a
Frequency of Inspection (number/tank/year)	12	
Percent of Tanks - Open Thief Hatch	0%	
Percent of Tanks - Open Dump Valves	0%	
Annual Average Hours Controls are Offline - Maintenance	24	
Annual Average Hours Controls are Offline - Other	8	
	Flare failures, site upsets, equipment failures, power losses	
Other - Description		
Sweetgrass Arch (MT)		
Fraction of Oil Production Represented	20%	not applicable
Spud Type	vertical	All
Tank Type	Oil Tank	Oil Tank
Gas Venting Rate (MCF/bbl)	0.01	0.01
Uncontrolled Flash VOC EF (lb VOC/bbl)	2.07	1.94
Percent of Tanks - Uncontrolled	100%	47%
Percent of Tanks - Flares	0%	53%
Percent of Tanks - Vapor Recovery Unit (VRU)	0%	0%
Percent of Tanks - Other Device	0%	0%
Other Device Control Type Description	-	-
Inspection Type	visual	a
Frequency of Inspection (number/tank/year)	0	

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Percent of Tanks - Open Thief Hatch	0%	
Percent of Tanks - Open Dump Valves	0%	
Annual Average Hours Controls are Offline - Maintenance	A	
Annual Average Hours Controls are Offline - Other		
Other – Description		
Williston Basin (MT)		
Fraction of Oil Production Represented	44%	not applicable
Spud Type	Horizontal	All
Tank Type	Oil Tank	Oil Tank
Gas Venting Rate (MCF/bbl)	0.04	0.06
Uncontrolled Flash VOC EF (lb VOC/bbl)	3.75	5.33
Percent of Tanks - Uncontrolled	1%	17%
Percent of Tanks - Flares	99%	83%
Percent of Tanks - Vapor Recovery Unit (VRU)	0%	0%
Percent of Tanks - Other Device	0%	0%
Other Device Control Type Description	Combustor	-
Inspection Type	LDAR/OGI/Visual/FLI RR/AVO/site sound smell	a
Frequency of Inspection (number/tank/year)	11	
Percent of Tanks - Open Thief Hatch	4%	
Percent of Tanks - Open Dump Valves	0%	
Annual Average Hours Controls are Offline - Maintenance	13	
Annual Average Hours Controls are Offline - Other	132	
Other - Description	Equipment failure or repair needed	
Williston Basin (MT)		
Fraction of Oil Production Represented	41%	not applicable
Spud Type	Vertical	All
Tank Type	Oil Tank	Oil Tank
Gas Venting Rate (MCF/bbl)	0.05	0.06
Uncontrolled Flash VOC EF (lb VOC/bbl)	4.50	5.33
Percent of Tanks - Uncontrolled	26%	17%
Percent of Tanks - Flares	74%	83%

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Percent of Tanks - Vapor Recovery Unit (VRU)	0%	0%
Percent of Tanks - Other Device	0%	0%
Other Device Control Type Description	-	-
Inspection Type	Routine	a
Frequency of Inspection (number/tank/year)	12	
Percent of Tanks - Open Thief Hatch	0%	
Percent of Tanks - Open Dump Valves	0%	
Annual Average Hours Controls are Offline - Maintenance	24	
Annual Average Hours Controls are Offline - Other	8	
Other - Description	Equipment failure or repair needed	
Williston Basin (ND)		
Fraction of Oil Production Represented	51%	not applicable
Spud Type	Horizontal	All
Tank Type	Oil Tank	Oil Tank
Gas Venting Rate (MCF/bbl)	0.08	0.07
Uncontrolled Flash VOC EF (lb VOC/bbl)	2.18	5.64
Percent of Tanks - Uncontrolled	0%	17%
Percent of Tanks - Flares	98%	83%
Percent of Tanks - Vapor Recovery Unit (VRU)	1%	0%
Percent of Tanks - Other Device	1%	0%
Other Device Control Type Description	Combustor	-
Inspection Type	LDAR/OGI/Visual/FLI RR/AVO	a
Frequency of Inspection (number/tank/year)	7	
Percent of Tanks - Open Thief Hatch	9%	
Percent of Tanks - Open Dump Valves	5%	
Annual Average Hours Controls are Offline - Maintenance	23	
Annual Average Hours Controls are Offline - Other	492	
Other - Description	Equipment failure or repair need	
Williston Basin (ND)		
Fraction of Oil Production Represented	24%	not applicable

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Spud Type	Vertical	All
Tank Type	Oil Tank	Oil Tank
Gas Venting Rate (MCF/bbl)	0.02	0.07
Uncontrolled Flash VOC EF (lb VOC/bbl)	1.33	5.64
Percent of Tanks - Uncontrolled	1%	17%
Percent of Tanks - Flares	99%	83%
Percent of Tanks - Vapor Recovery Unit (VRU)	0%	0%
Percent of Tanks - Other Device	0%	0%
Other Device Control Type Description	Combustor	-
Inspection Type	LDAR/OGI/Visual/AVO	a
Frequency of Inspection (number/tank/year)	4	
Percent of Tanks - Open Thief Hatch	0%	
Percent of Tanks - Open Dump Valves	1%	
Annual Average Hours Controls are Offline - Maintenance	A	
Annual Average Hours Controls are Offline - Other		
Other – Description		

^a Not enough information is available to populate this field

Table A4. Baseline Emission Inventory Inputs: Condensate Tanks.

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Sweetgrass Arch (MT)		
Fraction of Condensate Production Represented	14%	not applicable
Spud Type	Vertical	All
Tank Type	Condensate Tank	Condensate Tank
Gas Venting Rate (MCF/bbl)	0.13	0.15
Uncontrolled Flash VOC EF (lb VOC/bbl)	6.40	7.00
Percent of Tanks - Uncontrolled	100%	31%
Percent of Tanks - Flares	0%	69%
Percent of Tanks - Vapor Recovery Unit (VRU)	0%	0%
Percent of Tanks - Other Device	0%	0%
Other Device Control Type Description	-	-
Inspection Type	visual	a

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Frequency of Inspection (number/tank/year)	12	
Percent of Tanks - Open Thief Hatch	0%	
Percent of Tanks - Open Dump Valves	0%	
Annual Average Hours Controls are Offline - Maintenance	A	
Annual Average Hours Controls are Offline – Other		
Other – Description		
Williston Basin (MT)		
Fraction of Condensate Production Represented	65%	not applicable
Spud Type	Horizontal	All
Tank Type	Condensate Tank	Condensate Tank
Gas Venting Rate (MCF/bbl)	0.17	0.30
Uncontrolled Flash VOC EF (lb VOC/bbl)	11.36	14.08
Percent of Tanks - Uncontrolled	4%	8%
Percent of Tanks - Flares	95%	91%
Percent of Tanks - Vapor Recovery Unit (VRU)	0%	0%
Percent of Tanks - Other Device	1%	0%
Other Device Control Type Description	Combustor	-
Inspection Type	LDAR	a
Frequency of Inspection (number/tank/year)	2	
Percent of Tanks - Open Thief Hatch	14%	
Percent of Tanks - Open Dump Valves	0%	
Annual Average Hours Controls are Offline - Maintenance	48	
Annual Average Hours Controls are Offline - Other	480	
Other - Description	Equipment failure or repair needed	
Williston Basin (ND)		
Fraction of Condensate Production Represented	<1%	not applicable
Spud Type	Horizontal	All
Tank Type	Condensate Tank	Condensate Tank
Gas Venting Rate (MCF/bbl)	0.09	0.31
Uncontrolled Flash VOC EF (lb VOC/bbl)	10.53	14.72
Percent of Tanks - Uncontrolled	1%	8%
Percent of Tanks - Flares	99%	92%
Percent of Tanks - Vapor Recovery Unit (VRU)	0%	0%
Percent of Tanks - Other Device	1%	0%
Other Device Control Type Description	Combustor	-
Inspection Type	A	a
Frequency of Inspection (number/tank/year)		

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Percent of Tanks - Open Thief Hatch		
Percent of Tanks - Open Dump Valves		
Annual Average Hours Controls are Offline – Maintenance		
Annual Average Hours Controls are Offline – Other		
Other – Description		
Big Horn Basin (MT)		
Survey response was limited to one operator, comprising a very small fraction of activity, therefore, no input factors were developed.		
Central Montana Uplift (MT)		
Survey response was limited to one operator, comprising a very small fraction of activity, therefore, no input factors were developed.		

^a Not enough information is available to populate this field

Table A5. Baseline Emission Inventory Inputs: Wellsite Engines.

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Sweetgrass Arch (MT) - Wellhead Compressor Engines		
Fraction of Well Count Represented	30%	not applicable
Spud Type	Vertical	All
Well Type	Gas	Gas
Fuel Type	Natural Gas	Natural Gas
Number of engines per well	1.0	0
Rated Horsepower (hp/engine)	121	135
Hours of Operation (hours/engine)	740	0
Percent of Engines Electrified (%)	0%	0%
Average Engine Turnover Frequency (years)	a	a
If Other - Fuel Type	-	-
If NG - Percent of Engines - Lean Burn	21%	30%
If NG - Percent of Engines - Rich Burn	79%	70%
Percent of Engines Meeting NSPS subpart JJJJ Standards	a	a
Big Horn Basin (MT) - Lateral Compressor Engines		
Fraction of Well Count Represented	14%	not applicable
Spud Type	Vertical	All
Well Type	Gas	Gas
Fuel Type	Natural Gas	Natural Gas
Number of Wells per Engine	31	35

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Rated Horsepower (hp/engine)	237	271
Hours of Operation (hours/engine)	8760	8760
Percent of Engines Electrified (%)	0%	0%
Average Engine Turnover Frequency (years)	40	a
If Other - Fuel Type	-	-
If NG - Percent of Engines - Lean Burn	20%	20%
If NG - Percent of Engines - Rich Burn	80%	80%
Percent of Engines Meeting NSPS subpart JJJ Standards	a	a
Central Montana Uplift (MT) - Lateral Compressor Engines		
Fraction of Well Count Represented	82%	not applicable
Spud Type	Vertical	All
Well Type	Gas	Gas
Fuel Type	Natural Gas	Natural Gas
Number of Wells per Engine	28	129
Rated Horsepower (hp/engine)	277	443
Hours of Operation (hours/engine)	4576	8559
Percent of Engines Electrified (%)	0%	0%
Average Engine Turnover Frequency (years)	a	a
If Other - Fuel Type	-	-
If NG - Percent of Engines - Lean Burn	11%	61%
If NG - Percent of Engines - Rich Burn	89%	39%
Percent of Engines Meeting NSPS subpart JJJ Standards	a	a
Sweetgrass Arch (MT) - Artificial Lift Engines		
<i>Survey response was limited to one operator, comprising a very small fraction of activity, therefore, no input factors were developed.</i>		
Williston Basin (MT) - Artificial Lift Engines		
Fraction of Well Count Represented	48%	not applicable
Spud Type	Vertical	All
Well Type	Oil	Oil
Fuel Type	Natural Gas	Natural Gas
Number of engines per well	0.78	0.23
Rated Horsepower (hp/engine)	96	65
Hours of Operation (hours/engine)	6841	7930
Percent of Engines Electrified (%)	95%	21%
Average Engine Turnover Frequency (years)	a	a
If Other - Fuel Type	-	-
If NG - Percent of Engines - Lean Burn	0%	0%
If NG - Percent of Engines - Rich Burn	100%	100%

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Percent of Engines Meeting NSPS subpart JJJJ Standards	0%	a
Williston Basin (ND and MT) - Artificial Lift Engines		
Fraction of Well Count Represented	49%	not applicable
Spud Type	Horizontal	All
Well Type	Oil	Oil
Fuel Type	Natural Gas	Natural Gas
Number of engines per well	0.51	0.22
Rated Horsepower (hp/engine)	242	70
Hours of Operation (hours/engine)	8322	8538
Percent of Engines Electrified (%)	76%	17%
Average Engine Turnover Frequency (years)	6	a
If Other - Fuel Type	-	-
If NG - Percent of Engines - Lean Burn	76%	0%
If NG - Percent of Engines - Rich Burn	24%	100%
Percent of Engines Meeting NSPS subpart JJJJ Standards	42%	a
Williston Basin (ND) - Artificial Lift Engines		
Fraction of Well Count Represented	10%	not applicable
Spud Type	Vertical	All
Well Type	Oil	Oil
Fuel Type	Natural Gas	Natural Gas
Number of engines per well	0.33	0.22
Rated Horsepower (hp/engine)	66	70
Hours of Operation (hours/engine)	8384	8538
Percent of Engines Electrified (%)	52%	17%
Average Engine Turnover Frequency (years)	18	a
If Other - Fuel Type	-	-
If NG - Percent of Engines - Lean Burn	48%	0%
If NG - Percent of Engines - Rich Burn	52%	100%
Percent of Engines Meeting NSPS subpart JJJJ Standards	a	a
Permian Basin (MT) - Artificial Lift Engines		
Fraction of Well Count Represented	19%	not applicable
Spud Type	Horizontal	All
Well Type	Oil	Oil
Fuel Type	Natural Gas	Natural Gas
Number of engines per well	0.42	0.97
Rated Horsepower (hp/engine)	373	21
Hours of Operation (hours/engine)	8760	4380
Percent of Engines Electrified (%)	14%	70%

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors	
Average Engine Turnover Frequency (years)	a	a	
If Other - Fuel Type	-	-	
If NG - Percent of Engines - Lean Burn	26%	0%	
If NG - Percent of Engines - Rich Burn	74%	100%	
Percent of Engines Meeting NSPS subpart JJJJ Standards	99%	a	
Williston Basin (MT and ND) – Generators			
Fraction of Well Count Represented	65%	A	
Spud Type	Horizontal		
Well Type	Oil		
Fuel Type	Natural Gas		
Number of engines per well	0.03		
Rated Horsepower (hp/engine)	327		
Hours of Operation (hours/engine)	6094		
Percent of Engines Electrified (%)	16%		
Average Engine Turnover Frequency (years)	5.6		
If NG - Percent of Engines - Lean Burn	10%		
If NG - Percent of Engines - Rich Burn	90%		
Percent of Engines Meeting NSPS subpart JJJJ Standards	97%		
Fuel Type	Diesel		
Number of engines per well	0.02		
Rated Horsepower (hp/engine)	222		
Hours of Operation (hours/engine)	8760		
Percent of Engines Electrified (%)	0%		
Average Engine Turnover Frequency (years)	3		
Percent of Engines Meeting NSPS subpart JJJJ Standards	a		
Permian Basin – Generators			
Survey response was limited to one operator. Since this source category is not included in the WRAP OGWG v2 emission inventory, it was not possible to develop input factors due to confidentiality considerations.			
Permian Basin – Vapor Recovery Unit Engines			
Survey response was limited to one operator. Since this source category is not included in the WRAP OGWG v2 emission inventory, it was not possible to develop input factors due to confidentiality considerations.			

^a Not enough information is available to populate this field

Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources

Background Technical Support Document for the
Final New Source Performance Standards
40 CFR Part 60, subpart OOOOa

May, 2016

Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources

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DISCLAIMER

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ACRONYMS AND ABBREVIATIONS

<u>Acronyms/Abbreviations</u>	<u>Description</u>
µg/L	micrograms per liter
AEO	Annual Energy Outlook
ANGA	America's Natural Gas Alliance
API	American Petroleum Institute
bbl	barrels
BSER	best system of emission reduction
BTEX	benzene, toluene, ethylbenzene and xylenes
Btu	British thermal unit
CAA	Clean Air Act
CAGR	compound annual growth rate
CD	combustion device
CETAC-WEST	Canadian Environmental Technology Advancement Corporation-WEST
cfm	cubic foot per minute
CFR	U.S. Code of Federal Regulations
CH ₄	methane
CIPs	chemical injection pumps
CO	carbon monoxide
CO ₂	carbon dioxide
CO ₂ Eq.	carbon dioxide equivalents
COOGCC	Colorado Oil and Gas Conservation Commission
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FR	Federal Register
GE	General Electric
GHG	greenhouse gas
GOR	gas to oil ratio
GRI	Gas Research Institute
H ₂ S	hydrogen sulfide
HAP	hazardous air pollutants
Inj/With	injection/withdrawal
IR	infrared
kg/hr/comp	kilograms per hour per component
kg/hr/source	kilograms per hour per source
kW	kilowatt
lbs	pounds
LDAR	leak detection and repair
Mcf	thousand cubic feet
MMcf	million cubic feet
MMT	million metric tons

<u>Acronyms/Abbreviations</u>	<u>Description</u>
MMtCO ₂ e	million metric tons of CO ₂ -equivalents
Mscf	thousand standard cubic feet
Mscf/cyl	thousand standard cubic feet per cylinder
Mscf/yr	thousand standard cubic feet per cylinder per year
NEMS	National Energy Modeling System
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NGL	natural gas liquids
NO _x	nitrogen oxides
NSPS	New Source Performance Standards
O&M	operations & maintenance
OAQPS	Office of Air Quality and Standards
OAR	Office of Air and Radiation
OEL	open-ended line
OGI	optical gas imaging
OVA	organic vapor analyzers
PES	Preliminary Environmental Study
PG&E	Pacific Gas & Electric
PM	particulate matter
PNAS	Proceedings of the National Academy of Sciences
ppmv	parts per million by volume
PRV	pressure relief valve
psig	pounds per square inch gage
REC	renewable energy certificate
scf	standard cubic feet
scf/hr-cylinder	standard cubic feet per hour-cylinder
scf/minute or scfm	standard cubic feet per minute
scfh	standard cubic feet per hour
SO ₂	sulfur dioxide
THC	total hydrocarbon
TOC	total organic compounds
tpy	tons per year
TSD	Technical Support Document
TVA	toxic vapor analyzers
U.S.	United States
U.S.C.	United States Code
URS Corporation	United Research Services Corporation
UT Austin	University of Texas, Austin
VOC	volatile organic compounds
VRU	Vapor recovery unit
WAQD	Wyoming's Air Quality Division

1.0 INTRODUCTION

This background technical support document (TSD) provides information relevant to the development of the final rule Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources. The final rule establishes GHG standards, in the form of limitations on methane, for certain sources that are currently regulated for VOC but not GHG. It also establishes both VOC and GHG standards certain sources that are currently unregulated for either emissions.

Chapter 2 presents an overview of the oil and natural gas sector and source category. This chapter is intended to provide introductory material on the oil and natural gas source category, as listed under section 111(b)(1)(A).

The remainder of the TSD is presented in two volumes; Volume 1 provides the unit-level analysis supporting the determination of the best system of emission reduction (BSER); and Volume 2 presents the national impacts of the regulatory decisions for the final rule.

1.1 Volume 1 - Unit-Level BSER Analysis

Chapters 3 through Chapter 7 present detailed information and analyses pertaining to each emissions source that was considered in this regulatory action. They include emission data and discussions of available control options and their costs that are considered in the development of standards reflecting the BSER for these emission sources.

1.2 Volume 2 - National Level Impacts

Chapters 8 through Chapter 15 present the estimates of national level impacts needed to inform the Preamble of the final rule and the Regulatory Impact Analysis (RIA) for the rule, as required under Executive Order 12866. Specifically, each chapter summarizes the national baseline, nationwide emission reductions and cost impacts for use in the Preamble and RIA. It is important to note that that national impacts estimates incorporate in to the baseline the fact that some states already have requirements of emissions sources addressed by this final rule. Further, this analysis is separate and apart from the analyses required to identify the BSER based on which standards are to be established under section 111(b) of the CAA. Chapter 13 summarizes the natural gas savings from the application of emissions controls.

Finally, the Appendix to the TSD provides technical information on the background and development of the low pressure well equation.

1.3 Supporting Documentation

This action follows the development of several prior oil and gas NSPS related actions. This review references several documents that were published as a consequence of these prior actions. For ease of presentation, the following documents are consistently cited in the following sections:

- The TSD for the 2011 NSPS proposal, published in July, 2011, will be referred to in this document as "2011 NSPS TSD".¹
- The supplemental TSD for the 2012 final NSPS standards, published April, 2012, will be referred to in this document as "2012 NSPS STSD".²
- The gas composition memo that was developed during the NSPS process which characterizes and analysis of data to determine the gas composition and develop ratios for natural gas composition to be used for the various segments in the development of regulations for the oil and natural gas sector. This document will be referred to as "2011 Gas Composition Memorandum".³
- Emissions information and counts for various emission sources were developed from facility-level data submitted to the Greenhouse Gas Reporting Program (GHGRP) and data used to calculate national emissions in the Inventory of U.S. Greenhouse Gas Emissions and Sinks. The most recent available data from the GHG Inventory at the time of the development of this analysis was for 2013, and was used for various portions of the analysis. For the purposes of this document these data sources are referred to as "GHGRP" and "GHG Inventory". Currently available GHGRP reported data cover 2011 through 2014 and the most recent available GHG Inventory covers data from 1990-2014.⁴ These new activity data have been reviewed for the final rule and incorporated into this analysis appropriate
- The TSD for the 2015 NSPS proposal, published in August, 2015, will be referred to in this document as "2015 NSPS Proposal TSD". Note that this TSD includes all information from the proposal TSD that did not change and that continues to support the decisions of final rule, as well

¹ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Technical Support Document for Proposed Standards*. July 2011. EPA-453/R-11002.

² U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Supplemental Technical Support Document for Proposed Standards*. April 2012. Docket ID EPA-HQ-OAR-2010-0505-4550.

³ Memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. "Composition of Natural Gas for use in the Oil and Natural gas Sector Rulemaking". July 2011. Docket ID EPA-HQ-OAR-2010-0505-0084.

⁴ U.S. EPA. Public review draft of Inventory of U.S. Greenhouse Gas Emission and Sinks 1990-2014. Washington, DC

any revisions to relevant data or information that supports the provisions of the final rule.⁵

All of the calculations supporting the analyses in this document are included in the docket in the form of spreadsheets that are labeled corresponding to the section of the TSD.

⁵ See EPA-HQ-OAR-2010_0505-5021

2.0 OIL AND NATURAL GAS SOURCE CATEGORY OVERVIEW

The final rule covers emission sources within the oil and natural gas source category, which includes onshore crude oil production and natural gas production, processing, transmission and storage.

Production operations include the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, separation or treatment of oil and/or natural gas (including condensate). Production components may include, but are not limited to, wells and related casing head, tubing head and “Christmas tree” piping, as well as pumps, compressors, heater treaters, separators, storage vessels, pneumatic devices and dehydrators. Production operations also include well drilling, completion and recompletion processes; which includes all the portable non-self-propelled apparatus associated with those operations. Production sites include not only the “pads” where the wells are located, but also include stand-alone sites where oil, condensate, produced water and gas from several wells may be separated, stored and treated. The production segment also includes the low pressure, small diameter, gathering pipelines and related components that collect and transport the oil, gas and other materials and wastes from the wells to the refineries or natural gas processing plants.

There are two basic types of wells: oil wells and gas wells. Oil wells can have “associated” natural gas that is separated and processed or the crude oil can be the only product processed. Crude oil production includes the well and extends to the point of custody transfer to the crude oil transmission pipeline. Once the crude oil is separated from water and other impurities, it is essentially ready to be transported to the refinery via truck, railcar or pipeline. The oil refinery sector is considered separately from the oil and natural gas sector. Therefore, at the point of custody transfer at the refinery, the oil leaves the oil and natural gas sector and enters the petroleum refining sector.

Natural gas is primarily made up of methane. It commonly exists in mixtures with other hydrocarbons. They are sold separately and have a variety of different uses. The raw natural gas often contains water vapor, hydrogen sulfide (H₂S), carbon dioxide (CO₂), helium, nitrogen and other compounds. Natural gas processing consists of separating certain hydrocarbons and fluids from the natural gas to produce “pipeline quality” dry natural gas. While some of the processing can be accomplished in the production segment, the complete processing of natural gas takes place in the natural gas processing segment. Natural gas processing operations separate and recover NGL or other non-methane gases and liquids from a stream of produced natural gas through components performing one or more of the following processes: Oil and condensate separation, water removal, separation of natural gas liquids,

sulfur and CO₂ removal, fractionation of natural gas liquid and other processes, such as the capture of CO₂ separated from natural gas streams for delivery outside the facility.

The pipeline quality natural gas leaves the processing segment and enters the transmission and storage segment. Pipelines in the natural gas transmission and storage segment can be interstate pipelines that carry natural gas across state boundaries or intrastate pipelines, which transport the gas within a single state. While interstate pipelines may be of a larger diameter and operated at a higher pressure than intrastate pipelines, the basic components are the same. To ensure that the natural gas flowing through any pipeline remains pressurized, compression of the gas is required periodically along the pipeline. This is accomplished by compressor stations usually placed between 40 and 100 mile intervals along the pipeline. At a compressor station, the natural gas enters the station, where it is compressed by reciprocating or centrifugal compressors.

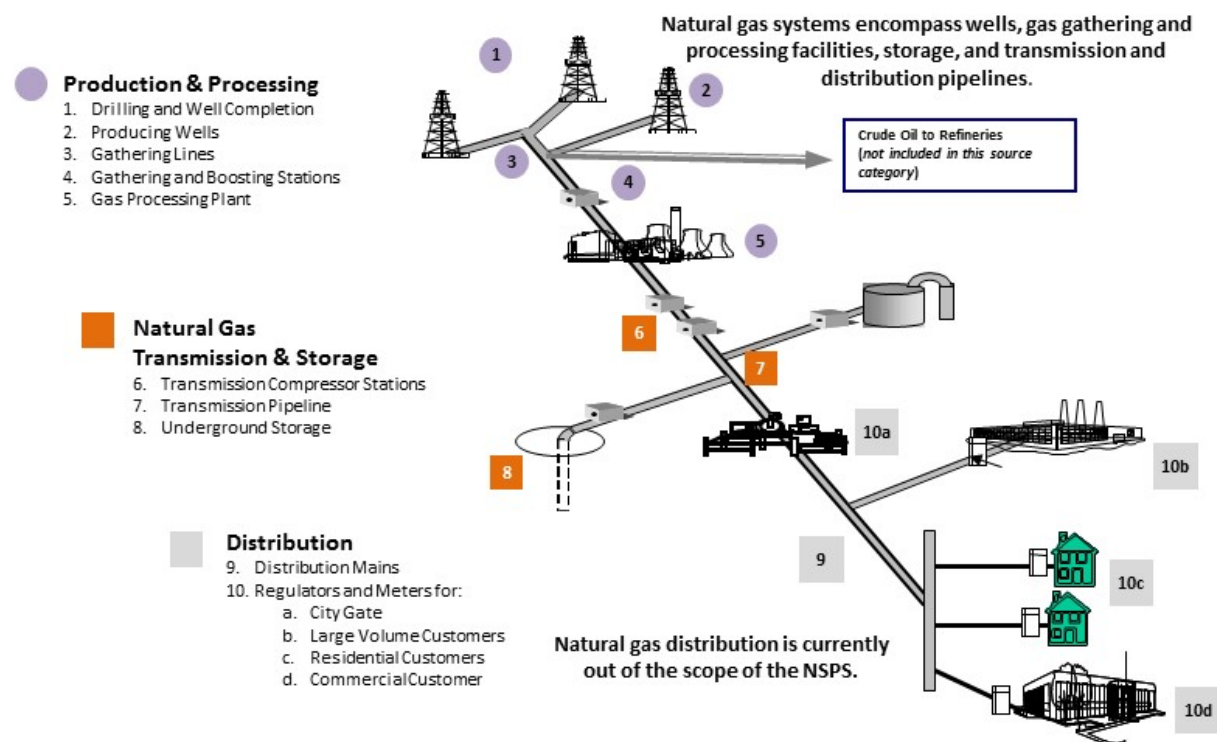
In addition to the pipelines and compressor stations, the natural gas transmission and storage segment includes aboveground and underground storage facilities. Underground natural gas storage includes subsurface storage, which typically consists of depleted gas or oil reservoirs and salt dome caverns used for storing natural gas. One purpose of this storage is for load balancing (equalizing the receipt and delivery of natural gas). At an underground storage site, there are typically other processes, including compression, dehydration and flow measurement.

Emissions can occur from a variety of processes and points throughout the oil and natural gas source category. Primarily, these emissions are organic compounds such as methane, ethane, VOC and organic HAP. The most common organic HAP are n-hexane and BTEX compounds (benzene, toluene, ethylbenzene and xylenes). Hydrogen sulfide and SO₂ are emitted from production and processing operations that handle and treat sour gas.⁶

The analysis in this document addresses only emission sources in the oil and natural gas source category. Unless otherwise noted, use of the term "gas" refers to natural gas.

⁶ Sour gas is defined as natural gas with a maximum H₂S content of 0.25 gr/100 scf (4 parts per million by volume (ppmv)) along with the presence of CO₂.

Oil and Gas Sector Description



Source: Adapted from American Gas Association and EPA Natural Gas STAR Program

Figure 1. Oil and Natural Gas Sector Operations

VOLUME 1: UNIT LEVEL BSER ANALYSIS

3.0 HYDRAULICALLY FRACTURED OIL WELL COMPLETIONS AND RECOMPLETIONS

During development of the 2012 NSPS amendments, methane and VOC emissions from hydraulically fractured oil and natural gas well completions and recompletions were estimated and included in the cost and impact analysis. See the 2011 NSPS TSD. The 2012 NSPS promulgated requirements for control of emissions from hydraulically fractured natural gas well completions and recompletions.

The EPA has reevaluated hydraulically fractured oil well completion emissions based on more recent data and information as discussed below. As was determined with respect to gas wells, oil well completions and recompletions use multi-phase processes with various sources of emissions where the highest emissions result from the venting of natural gas to the atmosphere during flowback. The flowback emissions are short-term in nature and occur as a specific event during completion of a new well or during recompletion activities that involve re-drilling or re-fracturing an existing well. This chapter describes hydraulically fractured oil well completions and recompletions, and provides estimates for representative oil wells and nationwide emissions. With respect to control technology, the same control technology can be employed to control emissions from oil well completions as were found to be appropriate for gas well completions. In this chapter, the EPA evaluated costs, emission reductions, and secondary impacts for oil well completions and recompletions based on the revised emissions profile.

Because oil well completions and recompletions were included in the proposed NSPS amendments in 2011 (76 FR 52738), for the sake of convenience the EPA repeat below the process description and control technology discussions from the 2012 NSPS TSD with minimal edits.

3.1 Process Description

3.1.1 Oil Well Completions

All oil wells must be “completed” after initial drilling in preparation for production.

Well completion activities include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and often hydraulically fracturing one or more zones in the reservoir to stimulate production. Surface components, including wellheads, pumps, dehydrators, separators, tanks, and

gathering lines are installed as necessary for production to begin.⁷

Developmental wells are drilled within known boundaries of a proven oil or gas field, and are located near existing well sites where well parameters are already recorded and necessary surface equipment is in place. When drilling occurs in areas of new or unknown potential, well parameters such as gas composition, flow rates of various phases (oil, gas, and water), oil API gravity, and pressure and temperature from the formation need to be ascertained before surface facilities required for production can be adequately sized and brought on site. In this instance, exploratory (also referred to as “wildcat”) wells and field boundary delineation wells typically either vent or combust the flowback gas.

One completion step for improving oil production is to fracture the reservoir rock with very high pressure fluid, typically a water emulsion with a proppant (generally sand) that “props open” the fractures after fluid pressure is reduced. Natural gas emissions are a result of the flowback of the fracture fluids and reservoir gas at high pressure and velocity necessary to clean and lift excess proppant to the surface. Natural gas from the completion flowback escapes to the atmosphere during the reclamation of water, sand, and hydrocarbon liquids during the collection of the multi-phase mixture directed to a surface impoundment. As the fracture fluids are depleted, the flowback eventually contains a higher volume of natural gas from the formation. Due to the specific additional equipment and resources involved and the nature of the flowback of the fracture fluids, completions involving hydraulic fracturing have higher costs and vent substantially more natural gas than completions not involving hydraulic fracturing.

3.1.2 Oil Well Recompletions Recompletions are remedial operations conducted to maintain production or minimize the decline in production. Examples of the variety of recompletion activities include completion of a new producing zone, re-fracture of a previously fractured zone, removal of paraffin buildup, replacing rod breaks or tubing tears in the wellbore, and addressing a malfunctioning downhole pump. During a recompletion, portable equipment is conveyed back to the well site temporarily and some recompletions require the use of a service rig. As with well completions, recompletions are highly specialized activities, requiring special equipment, and are usually performed by well service contractors specializing in well maintenance. Any flowback event during a recompletion, such as after a hydraulic fracture, will result in emissions to the atmosphere

⁷ U.S. EPA. Lessons Learned: Reduced Emissions Completions. Office of Air and Radiation (OAR): Natural Gas Star Program, Washington, DC, 2011.

When hydraulic re-fracturing (recompletions) is performed, the emissions are essentially the same as new well completions involving hydraulic fracture, except that surface gas collection equipment will already be present at the wellhead after the initial fracture. The flowback velocity during re-fracturing will typically be too high for the normal wellhead equipment (separator, dehydrator, lease meter), while the production separator is not typically designed for separating sand.

Flowback emissions are a result of free gas being produced by the well following hydraulic fracturing during a well completion and recompletion activity. The high rate flowback, with intermittent slugs of water and sand along with free gas, is directed to an impoundment or vessels until the well is fully cleaned up, where the free gas vents to the atmosphere while the water and sand remain in the impoundment or vessels. Therefore, nearly all of the flowback emissions originate from the recompletion process but may be vented as the flowback enters the impoundment or vessels.

3.2 Emission Data and Emission Factors

3.2.1 Summary of Major Studies and Emission Factors

Together with the sources of information and data reviewed during the development of the 2012 NSPS, the EPA reviewed recent data and information as was discussed in the white paper titled "Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production" published by the EPA in April, 2014.⁸ Table 3-1 presents a list of the studies and information sources consulted for development of the NSPS and the 2014 white paper. The list below includes sources with information on hydraulically fractured gas and oil well completions and workovers.

Table 3-1. Major Studies Reviewed Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factor(s)	Emission Information	Control Information
Drilling Info database	HPDI	2015	Nationwide	X	
GHG Mandatory Reporting Rule and Technical Supporting Documents ^a	EPA	2013	Nationwide	X	

⁸ Available at <http://www.epa.gov/airquality/oilandgas/2014papers/20140415completions.pdf>.

Report Name	Affiliation	Year of Report	Activity Factor(s)	Emission Information	Control Information
Inventory of GHG Emissions and Sinks: 1990-2013 ^{b, c}	EPA	2015	Nationwide	X	
Methane Emissions from the U.S. Petroleum Industry (Draft) ^d	Radian	1996	Nationwide	X	
Methane Emissions from the U.S. Petroleum Industry ^e	ICF	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States ^f	Western Regional Air Partnership	2005	Regional	X	X
Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories ^g	Central States Regional Air Partnership	2008	Regional	X	X
Oil and Gas Producing Industry in Your State ^h	Independent Petroleum Association of America	2009	Nationwide		
Emissions from Oil and Natural Gas Production Facilities ⁱ	Texas Commission for Environmental Quality	2007	Regional	X	X
Petroleum and Natural Gas Statistical Data ^j	U.S. Energy Information Administration (EIA)	2007-2009	Nationwide		
Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations ^k	EPA	1999		X	
Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program ^l	New York State Department of Environmental Conservation	2009	Regional	X	X
Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Supplemental Technical Support Document for the Final New Source Performance Standards ^m	EPA	2012	Nationwide	X	X
Fort Berthold Federal Implementation Plan ⁿ	EPA	2012	Regional	X	X
ERG/EC/R Contractor Analysis of HPDI® Data ^o	EPA	2012	Nationwide	X	X
Environmental Defense Fund Analysis of HPDI Data ^p	EDF	2014	Nationwide	X	X

Report Name	Affiliation	Year of Report	Activity Factor(s)	Emission Information	Control Information
Measurement of Methane Emissions at Natural Gas Production Sites in the United States ^q	Allen et al.	2014	Nationwide	X	X
Methane Leaks from North American Natural Gas Systems ^r	Brandt et al.	2014	Nationwide	X	X

- a. U.S. EPA. GHG Emissions Reporting From the Petroleum and Natural Gas Industry: Background TSD. Climate Change Division. Washington, DC. November 2010. 84-89 pp.
- b. U.S. EPA. Annex 3.5: Methodology for Estimating CH₄ and CO₂ Emissions from Petroleum Systems. Inventory of GHG Emissions and Sinks: 1990-2013. Washington, DC. 2015.
- c. U.S. EPA. Annex 3.6: Methodology for Estimating CH₄ and CO₂ Emissions from Natural Gas Systems. Inventory of GHG Emissions and Sinks: 1990-2013. . Washington, DC. 2015.
- d. Radian International LLC, Methane Emissions from the U.S. Petroleum Industry, draft report for the U.S. EPA, June 14, 1996.
- e. ICF Consulting. Estimates of Methane Emissions from the U.S. Oil Industry. Prepared for the U.S. EPA. 1999.
- f. ENVIRON International Corporation. Oil and Gas Emission Inventories for the WRAP. Prepared for Western Governors' Association. December 27, 2005.
- g. ENVIRON International Corporation. Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories Prepared for Central States Regional Air Partnership. November 2008.
- h. Independent Petroleum Association of America. Oil and Gas Producing Industry in Your State. 2008.
- i. Eastern Research Group, Inc. Emissions from Oil and Gas Production Facilities. Prepared for the Texas Commission on Environmental Quality. August 31, 2007.
- j. U.S. EIA. Annual U.S. Natural Gas Wellhead Price. EIA. Natural Gas Navigator. Retrieved December 12, 2010. <http://www.eia.doe.gov/dnav/ng/hist/n9190us3a.htm>.
- k. ERG, Inc. Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations. Prepared for the U.S. EPA. September 1999.
- l. New York State Department of Environmental Conservation. Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program (DRAFT). September 2009.
- m. See footnote 2.
- n. Fort Berthold Indian Reservation Federal Implementation Plan (78 FR 17836). U.S. Environmental Protection Agency (U.S. EPA). 2012a. *Technical Support Document, Federal Implementation Plan for Oil and Natural Gas Well Production Facilities; Fort Berthold Indian Reservation (Mandan, Hidatsa, and Arikara Nations), North Dakota*. Docket Number: EPA-R08-OAR-2012-0479.U.S. EPA.
- o. Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production. Washington, CD. 2014. Available at <http://www.epa.gov/airquality/oilandgas/2014papers/20140415completions.pdf>.
- p. Environmental Defense Fund (EDF). 2014. *Co-Producing Wells as a Major Source of Methane Emissions: A Review of Recent Analyses, March, 2014*. Available at <http://blogs.edf.org/energyexchange/files/2014/03/EDF-Co-producing-Wells-Whitepaper.pdf>. Supplemental materials available at <https://www.dropbox.com/s/osrom4w6ewow4ua/EDF-Initial-Production-Cost-Effectiveness-Analysis.xlsx>.
- q. Proceeding of the National Academy of Sciences of the United States of America (PNAS). 2013. *Measurement of Methane Emissions at Natural Gas Production Sites in the United States*. August 19, 2013. Available at <http://www.pnas.org/content/early/2013/09/10/1304880110.abstract>.
- r. Brandt, A.R., et al. 2014a. *Methane Leaks from North American Natural Gas Systems*. Science 343, 733 (2014). February 14, 2014. Available at <http://www.novim.org/images/pdf/ScienceMethane.02.14.14.pdf>.

3.2.2 Representative Completion and Recompletion Emissions

As previously mentioned, one specific emission source during completion and recompletion activities is the venting of natural gas to the atmosphere during flowback. Flowback emissions are short-term in nature and occur as a specific event during the completion of a new well or during recompletion activities that involve re-drilling or re-fracturing of an existing well. For this analysis, well completion

and recompletion emissions are estimated as the venting of emissions from the well following hydraulic fracturing during a well completion or recompletion activity.

This analysis assumes wells completed/recompleted with hydraulic fracturing are found in tight sand, shale, or coal bed methane formations. The basic approach for this analysis was to use natural gas production data to approximate natural gas emissions from representative oil well completions and recompletions and then estimate methane and VOC emissions using the representative gas composition values developed in the 2011 Gas Composition Memorandum for the 2012 NSPS.⁹

Based on the comments received during the development of the NSPS, the EPA recognized that there are instances where gas produced by a well is incidental to oil production and that the gas flow would not support operation of a separator if low levels of gas produced. Though, in theory, any amount of free gas could be separated from the liquid, the reality is that this is not practical given the design and operating parameters of separation units operating in the field. EIA data show that the number of "oil only" wells drilled from 2007-2012 was less than 20 percent.¹⁰ Therefore, the EPA evaluated available information to determine a minimum threshold of gas produced.

Non-volatile "black oils" (oil likely to not have gases or light hydrocarbons associated with it) are generally defined as having GOR values in the range of 200 to 900.¹¹ Therefore, oil wells with GORs less than 300 are at the lower end of this range, and likely will not have enough associated gas that can be separated.¹² Based on this consideration, the EPA concludes that a separator will not function at a well with a GOR of less than 300 scf/barrel and, therefore, well completion of such well would not be reasonably capable of capturing and controlling emissions. Consequently, removed these oil wells from our analysis conducted to determine emissions from hydraulically fractured oil wells.

The following methodology was used to estimate the potential methane and VOC emissions from hydraulically fractured oil well completions.

⁹ See U.S. EPA Docket ID Number EPA-HQ-OAR-2010-0505-0084.

¹⁰ <http://www.eia.gov/todayinenergy/detail.cfm?id=13571#>

¹¹ http://petrowiki.org/Oil_fluid_characteristics

¹² The reason for the proposed threshold GOR of 300 was that separators typically do not operate at a GOR less than 300, which is based on industry experience rather than a vetted technical specification for separator performance. Though in theory any amount of free gas could be separated from the liquid, in reality this is not practical given the design and operating parameters of separation units operating in the field. On February 24, 2015, API submitted a comment to EPA stating that oil wells with GOR values less than 300 do not have sufficient gas to operate a separator.

<http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2014-0831-0137>.

1. The EPA obtained well production data from the DrillingInfo database dated February, 2014.¹³ The DrillingInfo database consists of oil and natural gas well information maintained by a private organization that provides parameters describing the location, operator, and production characteristics. DrillingInfo collects information on a well basis such as the operator, state, basin, field, annual gas production, annual oil production, well depth, and shut-in pressure, all of which is aggregated from operator reports to state governments. The data extract from the DrillingInfo database included the population of all wells with gas or hydrocarbon liquid production during 2010 to 2012 and with a recorded completion year of 2010 to the date of the extract (February, 2014).
2. The data was then processed to identify oil wells that were hydraulically fractured using a methodology based on a crosswalk of formation types and other information. See the ERG memorandum titled "*2013 GHGRP Subpart W and NSPS/NESHAP DrillingInfo Processing Methodology*" available in the docket, for a detailed description of the process to identify hydraulically fractured oil wells from the total oil well population.
3. From the dataset of hydraulically fractured oil wells, the EPA identified the wells completed in 2012 using the "completion year" record or the year of the "first month of production". Wells with a completion year of 2012 could have been completed for the first time in 2012 or could have been re-completed (i.e., re-fractured in 2012). The EPA also removed from the dataset all wells not characterized in the DrillingInfo database as "oil," "gas" or "oil and gas".
4. For the above identified hydraulically fractured oil well population, the EPA calculated the gas to oil ratio (GOR) by dividing the standard cubic feet (scf) of gas produced during the first month of production by the barrels (bbl) of petroleum liquid produced during the first month. The EPA then used the GOR to categorize the wells into oil and gas wells. Oil wells were defined to be those wells with a GOR of less than 100,000 scf/bbl. This threshold was chosen because it is consistent with the threshold used in the EPA National Emissions Inventory Oil and Gas Emission Estimation Tool and the threshold used in several states, including Texas¹⁴ and New Mexico¹⁵.
5. Based on the calculated GOR for the wells identified above, the EPA eliminated from the

¹³ DrillingInfo is a private organization specializing in compiling primarily publically available oil and gas data, conducting statistical analysis, and providing analysis platforms for customers. The DrillingInfo database is particularly focused on historical oil and gas production data and drilling permit data.

¹⁴ Available at

[http://info.sos.state.tx.us/pls/pub/readtac\\$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=16&pt=1&ch=3&rl=79](http://info.sos.state.tx.us/pls/pub/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=16&pt=1&ch=3&rl=79).

¹⁵ Available at <http://164.64.110.239/nmac/parts/title19/19.015.0002.htm>.

evaluation wells with a GOR of less than 300 scf of gas per barrel produced.

6. The EPA then calculated the following average daily gas production values for each oil well;
 - Average daily gas production over the first month of operation by dividing the total gas production in the first month of operation by the average number of days in a month (30.42);
 - Average daily gas production over the first 6 months of operation by dividing the total gas production in the first six months of operation by the average number of days in 6 months (182.5); and
 - Average daily gas production over the first year of operation by dividing the total gas production in the first year of operation by the total days in one year (365).
7. The EPA assumed that the average daily gas production during the first month was representative of the daily potential emissions during a hydraulically fractured oil well completion. Therefore, the estimated gas production from a representative oil well completion was determined by taking the average of the average daily natural gas production during the first month of operation for each of the above identified oil wells (i.e., hydraulically fractured, and completed in 2012).
8. To determine the potential methane and VOC emissions for a representative oil well completion or recompletion, the EPA converted the average natural gas potential emissions per day to short tons of potential methane and VOC emissions. The conversion factors used are those developed for the NSPS and outlined in the memorandum titled "*Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking*", available in the docket.¹⁶ Specifically, the EPA assumes natural gas is 46.71% methane by volume, the density of methane is 0.0208 tons per Mcf, and that there is 0.8374 lbs of VOC per pound of methane.

The EPA then calculated the potential VOC and methane emissions during a hydraulically fractured oil well flowback by multiplying potential methane and VOC emissions per day by the number of days in the average flowback event. The data sources referenced in the white papers noted a range of flowback duration from 1-10 days. Some of the values in the ranges were based on study observation and some based on assumptions. Comments on the oil well completion white paper supported a flowback duration on the low end of the range. Our analysis assumes an oil well flowback duration is toward the low end of that range, 3 days.

¹⁶ See footnote 3.

Table 3-2 presents the estimated potential (i.e., uncontrolled) emissions from a representative oil well completion or recompletion. The data sources in the white papers and comments received on the white papers showed a broad range of potential emission estimates (8 to around 200 tons methane per completion or workover) for hydraulically fractured oil well completions. Some of the values were developed using data on gas production and assumptions about flowback; others used measurement data. As described above, the estimates presented in the table below were developed using flowback characteristics and gas production data and include the effect of a GOR threshold of 300 that excludes oil wells with very little gas production. The estimates in the table below represent emissions from that population of wells, in the absence of controls. To calculate emissions to the atmosphere using these values, additional information on gas that is not emitted (e.g., through use of RECs or flaring) is needed.

Table 3-2. Uncontrolled Emission Estimates from Representative Oil Well Completion or Recompletion

	Average Daily Production Natural Gas (Mcf/event)	Potential Emissions Methane ^a (tons/event)	Potential Emissions VOC ^b (tons/event)
3-Day Completion or Recompletion Event	999	9.72	8.14

a. It is assumed methane comprises 46.732 percent by volume of natural gas. The factor used to convert methane from volume to weight is 0.0208 tons methane per thousand cubic feet (Mcf) of methane.¹⁷

b. Assumes 0.8374 lb. VOC/lb. methane.

3.3 Control Techniques

3.3.1 Potential Control Techniques

The techniques that have been proven to reduce emissions from oil well completions and recompletions are the same as those that were evaluated for development of the 2012 NSPS for gas well completions and recompletions; specifically RECs and completion combustion. As with natural gas wells, the use of a REC not only reduces emissions but delivers natural gas product to the sales meter that would typically be vented. Completion combustion destroys the organic compounds. Based on our research as published in the oil completions white paper, these technologies have been found to be technically feasible for oil well completions and recompletions, and are in use in the industry to control emissions from oil wells. The EPA identified no other potential control options for oil well completions. For the sake of convenience, the description sections included below are from the 2012 NSPS TSD with limited edits. The

¹⁷ U.S EPA. Methodology for Estimating CH₄ and CO₂ Emissions from Petroleum Systems. Greenhouse Gas Inventory: Emission and Sinks 1990-2008. Washington, DC. 2010. Appendix B, Pgs. 87-89.

following sections describe the cost impact of these technologies with respect to oil well completions based on our current analysis of emissions.

3.3.2 Reduce Emission Completions and Recompletions

3.3.2.1 Description

Reduced emission completions, also referred to as “green” completions, use specially designed equipment at the well site to capture and treat gas during well completion activities. This process prevents some natural gas from venting and results in additional revenues for producers from the sale or use of captured gas and, if present, gas condensate. Additional equipment required to conduct a REC may include additional tankage, special gas-liquid-sand separator traps, and a gas dehydrator.¹⁸

In many cases, portable equipment used for RECs operate in tandem with the permanent equipment that will remain after well drilling is completed. In other instances, permanent equipment is designed (e.g. oversized) to specifically accommodate initial flowback. Some limitations exist for performing RECs since technical barriers fluctuate from well to well. Three main limitations include the following for RECs:

- Proximity of pipelines. For exploratory wells, no nearby sales line may exist. The lack of a nearby sales line incurs higher capital outlay risk for exploration and production companies and/or pipeline companies constructing lines in exploratory fields. The State of Wyoming has set a precedent by stating proximity to gathering lines for wells is not a sufficient excuse to avoid RECs unless they are deemed exploratory, or the first well drilled in an area that has never had oil and gas well production prior to that drilling instance (i.e., a wildcat well).¹⁹ In instances where formations are stacked vertically and horizontal drilling could take place, it may be possible that existing surface REC equipment may be located near an exploratory well, which would allow for a REC.
- Pressure of produced gas. During the completion/recompletion process, the pressure of flowback fluids may not be sufficient to overcome the gathering line backpressure. In this case, combustion of flowback gas is one option, either for the duration of the flowback or until a point during flowback when the pressure increases to flow to the sales line. Another potential

¹⁸ U.S. EPA Fact Sheet No. 703: Green Completions. OAR: Natural Gas Star Program. Washington, DC. September 2004.

¹⁹ Memorandum to Bruce Moore, U.S. EPA from Denise Grubert, EC/R. API Meeting Minutes. July 2010.

compressor application is to boost pressure of the flowback gas after it exits the separator. This technique is experimental because of the difficulty operating a compressor on widely fluctuating flowback rate.

- Inert gas concentration. If the concentration of inert gas, such as nitrogen or CO₂, in the flowback gas exceeds sales line concentration limits, venting or combustion of the flowback may be necessary for the duration of flowback or until the gas energy content increases to allow flow to the sales line. Further, since the energy content of the flowback gas may not be high enough to sustain a flame due to the presence of the inert gases, combustion of the flowback stream would require a continuous ignition source with its own separate fuel supply.

3.3.2.1 Emission Reduction Potential

RECs are an effective emission reductions method for oil well completions and recompletions performed with hydraulic fracturing based on the estimated flowback emissions described in Section 2.2. The emission reductions vary according to reservoir characteristics and other parameters including length of completion, number of fractured zones, pressure, gas composition, and fracturing technology/technique. Based on information presented in the white papers, this analysis assumes 90 percent of flowback gas can be recovered during a REC.²⁰ Any amount of gas that cannot be recovered can be directed to a combustion device in order to achieve a minimum 95 percent reduction in emissions.

3.3.2.2 Cost Impacts

All completions incur some costs to a company. Performing a REC will add to these costs. Equipment costs associated with RECs vary from well to well. High production rates may require larger equipment to perform the REC and will increase costs. If permanent equipment, such as a glycol dehydrator, is already installed or is planned to be in place at the well site as normal operations, costs may be reduced as this equipment can be used or resized rather than installing a portable dehydrator for temporary use during the completion. Some operators normally install equipment used in RECs, such as sand traps and three-phase separators, further reducing incremental REC costs. The EPA received information and comment from multiple technical experts that the equipment necessary to perform a REC for an oil well completion is the same as that for a gas well completion.

Therefore, as was determined in the 2011 NSPS TSD²¹, the annual cost of performing a REC

²⁰ Memorandum to Bruce Moore, U.S. EPA from ICF Consulting. Percent of Emissions Recovered by Reduced Emission Completions. May 2011.

²¹ See footnote 1.

was estimated to be \$12,735 for a representative well completion lasting 3 days²². For our analysis, the cost is adjusted to 2012 dollars using the Gross Domestic Product: Implicit Price Deflator.²³ The resulting cost for performing a REC for a well completion or recompletion lasting 3 days is estimated to be \$13,459.

Monetary savings associated with additional gas captured to the sales line is estimated based on a natural gas price of \$4.00 per Mcf.²⁴ It was assumed that all gas captured would be included as sales gas. Therefore, assuming that 90 percent of the gas is captured and sold, this equates to a total recovery of 899 Mcf of natural gas per completion or recompletion. The estimated value of the recovered natural gas for a representative natural gas well with hydraulic fracturing is approximately \$3,597. When considering these savings from REC, for a completion or recompletion with hydraulic fracturing, there is a net cost on the order of \$9,862 per completion.

RECs are considered one-time events per well; therefore annual costs were conservatively assumed to be the same as capital costs. The cost per ton of emissions reduced was then calculated in two ways, both of which reflect that REC is a multi-pollutant control measure (VOC and GHG (in the form of limitations on methane)). The first method, the single-pollutant method, allocates all of the costs to one pollutant and zero to the other. The second method, the multi-pollutant method, allocates costs among the pollutants that a given technology reduced. This proration was based on estimates of the percentage reduction expected for each pollutant.

Based on expected emission reductions from the use of a REC, the cost of control for methane is \$1,539 per ton and \$1,837 per ton of VOC when 100 percent of the cost is attributed to one pollutant and zero cost to the other. The cost is \$769 per ton of methane and \$919 per ton of VOC when the total cost is allocated equally between methane and VOC (i.e., 50 percent to methane and 50 percent to VOC). Table 2-3 provides a summary of REC cost per ton of emission reduction.

Because a REC accomplishes gas savings, the cost of control for methane is \$1,127 per ton and \$1,346 per ton of VOC when 100 percent of the cost is attributed to one pollutant and zero cost to the

²² This cost was based on state of the industry in 2006 and adjusted to 2008 US Dollars. For the 2012 NSPS the EPA determined a cost per day value, however, the 2012 NSPS applied this per day cost to a 7-day event duration. Here the EPA use the same cost per day and a 3-day event duration.

²³ Available at <http://research.stlouisfed.org/fred2/series/GDPDEF/>.

²⁴ When including the additional natural gas recovery in the cost analysis, the EPA assume that producers are paid \$4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. The Energy Information Administration's 2014 Annual Energy Outlook forecasted wellhead prices paid to lower 48 state producers to be \$4.46/Mcf in 2020 and \$5.06/Mcf in 2025. The \$4/Mcf price assumed in this RIA is intended to reflect the AEO estimate but simultaneously be conservatively low.

other, and the monetary gas savings is considered. Likewise, the cost is \$564 per ton of methane and \$673 per ton of VOC when the total cost is reduced by the gas savings and is allocated equally between methane and VOC (i.e., 50 percent to methane and 50 percent to VOC). Table 2-3 provides a summary of REC cost per ton of emission reduction.

As mentioned earlier, during a well completion, gas that cannot be recovered with REC can be combusted. For the purposes of this analysis, the EPA also analyzed costs for the a REC combined with the cost of a combustion device as described below in section 2.3.3.1. For the combined REC and combustion scenario, the cost of control for methane is \$1,861 per ton and \$2,222 per ton of VOC when 100 percent of the cost is attributed to one pollutant and zero to the other. The cost is \$930 per ton of methane and \$1,111 per ton of VOC when the total cost is allocated equally between methane and VOC (i.e., 50 percent to methane and 50 percent to VOC).

When gas savings is considered, for the combined REC and combustion, the cost of control for methane is \$1,471 per ton and \$1,757 per ton of VOC when 100 percent of the cost is attributed to one pollutant and zero cost to the other, and the monetary gas savings is considered. Likewise, the cost is \$736 per ton of methane and \$879 per ton of VOC when the total cost is reduced by the gas savings and is allocated equally between methane and VOC (i.e., 50 percent to methane and 50 percent to VOC). Table 2-3 provides a summary of REC cost per ton of emission reduction.

3.3.2.3 Secondary Impacts

A REC is a pollution prevention technique that is used to recover natural gas that would otherwise be emitted. No secondary emissions (e.g., NO_x, PM, etc.) would be generated, no wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to REC.

3.3.3 Combustion Devices

3.3.3.1 Description

As mentioned earlier, during a well completion, gas that cannot be recovered with REC can be combusted. Combustion is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, found in waste streams.²⁵ Combustion devices are used to control VOC in many industrial settings, since these devices can normally handle fluctuations in concentration, flow rate,

²⁵ U.S. EPA. AP-42, Fifth Edition, Volume I, Chapter 13.5 Industrial Flares. OAQPS. 1991.

heating value, and inert species content.²⁶ Combustion devices commonly found on drilling sites are rather crude and portable, often installed horizontally due to the liquids that accompany the flowback gas. These devices can be as simple as a pipe with a basic ignition mechanism and discharge over a pit near the wellhead (i.e., a pit flare). The flow directed to a combustion device during a well completion may or may not be combustible depending on the inert gas composition of flowback gas, which would require a continuous ignition source. On the other end of the spectrum is the enclosed combustor that is specifically designed for completions that is an integral part of a completion equipment package. For the purpose of this analysis, the term combustion device represents any types of combustion devices used in the industry for control of hydrocarbon emissions.

3.3.3.2 Emission Reduction Potential

It is difficult to measure precisely the destruction efficiency of a combustion device during a well completion activity. The actual destruction efficiency achieved in practice can be expected to vary with the amount of noncombustible gas and liquids in the gas flow. For the purposes of this analysis, a destruction efficiency of 95 percent, consistent with the expected destruction efficiency of a properly designed and operated flare, was assumed for completion combustion devices over the duration of the completion or recompletion. If the energy content of natural gas is low, then the combustion mechanism can be extinguished by the flowback gas. Therefore, it is more reliable to install an igniter fueled by a consistent and continuous ignition source. This scenario would be especially true for energized fractures where the initial flowback concentration will be extremely high in inert gases. This analysis assumes the use of a continuous ignition source with an independent external fuel supply to achieve an average of 95 percent control over the entire flowback period. Additionally, because of the nature of the flowback (i.e., with periods of water, condensate, and gas in slug flow), conveying the entire portion of this stream to a completion combustion device or other control device is not always feasible. Because of the exposed flame, open pit flaring can present a fire hazard or other undesirable impacts in some situations (e.g., dry, windy conditions, proximity to residences). As a result, the design and nature of combustion devices used for completions must handle multiphase flow and stream compositions well site conditions that vary during the flowback period and not all unrecoverable gas can be safely combusted in every case.

²⁶ U.S. EPA. Air Pollution Control Technology Fact Sheet: FLARES. Clean Air Technology Center.

3.3.3.3 Cost Potential

An analysis estimating the cost for wells including combustion devices was conducted for the 2012 NSPS, resulting in an estimated average completion combustion device cost of approximately \$3,523 (2008 dollars).²⁷ For our analysis, this cost was adjusted to 2012 dollars using the Gross Domestic Product: Implicit Price Deflator²⁸ resulting in an estimated annual cost of \$3,723 per well completion. As with the REC, because completion combustion devices are purchased for these one-time events, annual costs were conservatively assumed to be equal to the capital costs.

It is assumed that the cost of a continuous ignition source is included in the combustion completion device cost estimate. It is understood that multiple completions and recompletions can be controlled with the same completion combustion device, not only for the lifetime of the combustion device but within the same yearly time period. However, to be conservative, costs were estimated as the total cost of the completion combustion device itself, which corresponds to the assumption that only one device will control one completion per year. The cost per ton of emissions reduced was then calculated in two ways. The first method (the single-pollutant approach) allocated all of the costs to one pollutant and zero cost to the other. The second method (the multi-pollutant approach) allocated costs among the pollutants that a given technology reduced (i.e., in this case GHG in the form of limitations on methane, and VOC). This allocation was based on estimates of the percentage reduction expected for each pollutant. Completion combustion devices have a cost of control of \$403 per ton of methane or \$481 per ton of VOC for oil well completions and recompletions when 100 percent of the cost is attributed to one pollutant and zero to the other. Under the multipollutant approach where the cost is prorated to both pollutants equally (i.e., a 50 percent to methane and 50 percent to VOC), the cost of control is \$202 per ton of methane and \$241 per ton of VOC. The cost impacts of using a completion combustion device to reduce emissions from representative completions/recompletions are provided in Table 3-3.

3.3.3.4 Secondary Impacts

Noise and heat are the two primary undesirable outcomes of completion combustion device operation. In addition, combustion and partial combustion of many pollutants also create secondary pollutants including NO_x, CO, sulfur oxides (SO_x), CO₂, and smoke/particulates. The degree of combustion depends on the rate and extent of fuel mixing with air and the temperature maintained by the

²⁷ The Chemical Engineering Cost Index was used to convert dollar years. For the combustion device the 2009 value equals the 2009 average value for the combustion device is \$3,195.

²⁸ Available at <http://research.stlouisfed.org/fred2/series/GDPDEF/>.

flame. Most hydrocarbons with carbon-to-hydrogen ratios greater than 0.33 are likely to smoke.²⁹ The high methane content of the gas stream routed to the completion combustion device suggests that there should not be smoke except in specific circumstances (e.g., energized fractures). The stream to be combusted may also contain liquids and solids that will also affect the potential for smoke. Soot can typically be eliminated by adding steam. Based on current industry trends in the design of completion combustion devices and in the decentralized nature of completions, virtually no completion combustion devices include steam assistance.³⁰

Reliable data for emission factors from flare operations during natural gas well completions are limited. Guidelines published in AP-42 for flare operations are based on tests from a mixture containing 80 percent propylene and 20 percent propane.³¹ These emissions factors, however, are the best indication for secondary pollutants from flare operations currently available. These secondary emission factors are provided in Table 3-5.

²⁹ See footnote 25.

³⁰ Ibid.

³¹ Ibid.

Table 3-3. Reduced Emission Completion and Combustion Emission Reductions and Cost Impacts Summary

Control Technology	Emissions Reduced Per Completion ^a (short tons)		Volume of Whole Gas Captured (Mcf/completion)	Value of Whole Gas Captured (\$/completion)	Annual Cost (\$)	Cost of Control Per Completion (excluding gas savings) (\$/short ton)		Cost of Control Per Completion (including gas savings) (\$/short ton)	
	Methane	VOC				Methane	VOC	Methane	VOC
REC (100) ^b	8.75	7.33	899	\$3,597	\$13,459	\$1,539	\$1,837	\$1,127	\$1,346
REC (50/50) ^c	8.75	7.33	899	\$3,597	\$13,459	\$769	\$919	\$564	\$673
REC and Combustion device (100) ^{b,d}	9.23	7.73	899	\$3,597	\$17,183	\$1,861	\$2,222	\$1,471	\$1,757
REC and Combustion device (50/50) ^{c,d}	9.23	7.73	899	\$3,597	\$17,183	\$930	\$1,111	\$736	\$879
Completion Combustion (100) ^b	9.23	7.73	0	\$0	\$3,723	\$403	\$481	\$403	\$481
Completion Combustion (50/50) ^c	9.23	7.73	0	\$0	\$3,723	\$202	\$241	\$202	\$241

a. Assumes 95% control.

b. Scenario where 100 percent of the cost of control is attributed to methane and VOC.

c. Scenario where 50 percent of the cost of control is attributed to methane and 50 percent is attributed to VOC.

d. Control option that combines use of a REC and a combustion device to attain 95 percent control.

Table 3-4. Emission Factors from Flare Operations from AP-42 Guidelines Table 13.4-1^a

Pollutant	Emission Factor (lb/MMBtu)
THC ^b	0.14
CO	0.31
NO _x	0.068
PM ^c	0-274
Pollutant	Emission Factor (kg CO₂/MMBtu)
CO ₂ ^d	60

a. Based on combustion efficiency of 98 percent.

b. Measured as methane-equivalent.

c. Soot in concentration values: nonsmoking flares, 0 micrograms per liter (µg/L); lightly smoking flares, 40 µg/L; average smoking flares, 177 µg/L; and heavily smoking flares, 274 µg/L.

d. Carbon dioxide factor is derived from the CO₂ emission factor obtained from 40 CFR Part 98, subpart Y, Equation Y-2.

3.4 Regulatory Options

The REC pollution prevention approach would not result in emissions of CO, NO_x, and particulate matter (PM) from the combustion of the completion gases in the completion combustion device. Taking this into consideration, the following regulatory alternatives were evaluated:

- Regulatory Option 1. Require combustion for all hydraulically fractured oil well completions and recompletions;
- Regulatory Option 2. Require REC for all hydraulically fractured oil well completions and recompletions;
- Regulatory Option 3. Require REC and combustion for hydraulically fractured oil well completions and recompletions where gas can be recovered with REC; and
- Regulatory Option 4. Require combustion where gas cannot be recovered with REC.

The following sections discuss these regulatory options.

3.4.1 Evaluation of Regulatory Options

Under Regulatory Option 1, nearly all of the natural gas emitted from the well during flowback would be destroyed by sending flowback gas through a combustion unit. Not only would this regulatory option result in the destruction of a natural resource with no recovery of salable gas, it also would result in an increase in emissions of secondary pollutants (e.g., NO_x, CO). Therefore, EPA rejected Regulatory

Option 1.

The second regulatory option would require RECs for all completions and recompletions of hydraulically fractured oil wells. As stated previously, RECs are not technically feasible for all well completions, such as exploratory wells due to their distance from sales lines. Further, RECs are also not always technically feasible for each well at all times during completion and recompletion activities due to the variability of the pressure of produced gas or inert gas concentrations.

The third regulatory option consists of a combination of REC and combustion for hydraulically fractured oil well completions. As discussed for Regulatory Option 2, RECs are not feasible for every well at all times during completion or recompletion activities due to variability of produced gas pressure or inert gas concentrations. In order to allow for owners and operators to continue to reduce emissions when RECs are not feasible due to well characteristics (e.g., wellhead pressure or inert gas concentrations), or infrastructure issues (e.g., absence of pipelines or processes on-site which can be used to route captured gas) Regulatory Option 3 also allows for the use of a completion combustion device in combination with RECs.

Under this option, some venting must be allowed in lieu of combustion for situations in which combustion would present safety hazards, other concerns.

Regulatory Option 4 reduces emissions through combustion in situation where gas cannot be recovered through REC (for exploratory and delineation wells due to their distance from sales lines, low pressure wells).

4.0 FUGITIVE EMISSIONS STANDARDS

In the TSD for the proposed rule, monitoring options for reducing fugitive emissions from well sites and compressor stations were analyzed. The monitoring options that were analyzed included optical gas imaging (OGI) and Method 21 at monitoring frequencies of annual, semiannual and quarterly. For Method 21 repair thresholds of 10,000 ppm, 2,500 ppm and 500 ppm were also analyzed for each of the monitoring frequencies. Based on the analysis in the proposed rule TSD, the semiannual OGI monitoring option was selected as BSER for well sites and compressor stations. Comments on the proposed BSER analysis were received during the proposed rule comment period, and the BSER analysis for the OGI option was re-evaluated to take into account these comments. In response to comments, Method 21 was also re-evaluated as an alternative option for fugitive emission monitoring.

4.1 Fugitive Emissions Description

There are several potential sources of fugitive emissions throughout the oil and natural gas source category. Fugitive emissions occur when connection points are not fitted properly or when seals and gaskets start to deteriorate. Changes in pressure and mechanical stresses can also cause components or equipment to emit fugitive emissions. Poor maintenance or operating practices, such as improperly reseated PRVs or thief hatches on controlled storage vessels that are left open after sampling, are also potential sources of fugitive emissions. Potential sources of fugitive emissions include agitator seals, connectors, pump diaphragms, flanges, instruments, meters, open-ended lines (OELs), pressure relief devices such as pressure release valves (PRVs), pump seals, valves or improperly controlled liquid storage tanks. These fugitive emissions do not include devices that vent as part of normal operations, such as gas driven pneumatic controllers or gas driven pneumatic pumps, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission.

For the purposes of the analysis and regulatory evaluation of fugitive emissions from components and equipment, the EPA differentiated between the current definition of "equipment" in the rule³² and the intended definition for the purposes of addressing fugitive emissions. Therefore in the final rule, the EPA have defined a new term, "fugitive emissions component" as the focus of the

³² The Oil and Natural Gas Sector NSPS (40 CFR 60, subpart OOOO) specifically defines "equipment" relative to standards for equipment leaks of VOC from onshore natural gas processing plants. As used in this chapter, the term "equipment" is used in a broader context and is not meant to be limited by the manner in which the term is currently used in subpart OOOO.

requirements for fugitive emissions. The proposed definition for fugitive emissions component is as follows:

Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as a gas-driven pneumatic controller or a gas-driven pump, are not fugitive emissions components, insofar as the gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from sites other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.

The EPA received comment that this proposed fugitive emissions component definition was too broad and vague and may include equipment such as separators, pressure vessels, and dehydrators instead of the components (i.e., valves, connectors) on the equipment. The commenters also asserted that the "included but not limited to" description adds uncertainty to what should be included in the collection of fugitive emissions components. Based on these comments, the EPA has revised the definition of fugitive emissions component in the final rule to read:

Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to §60.5411a, thief hatches or other openings on a controlled storage vessel not subject to §60.5395a, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

In April of 2014, the EPA published a white paper³³ which summarized the EPA's current understanding of methane and VOC fugitive emissions at onshore oil and natural gas production, processing and transmission and storage facilities. The white paper also outlined the EPA's understanding of the available mitigation techniques (practices and equipment) available to reduce these emissions along with the cost and emission reduction potential of these practices and technologies.

4.2 Fugitive Emissions Data and Emissions Factors

4.2.1 Model Plants

For the proposed rule, model plants were developed to estimate fugitive emissions from well sites and compressor stations. Data from the 2016 draft GHG Inventory³⁴, developed with the most recently published GHGRP reported data, were used to determine the equipment counts for well sites and compressor stations. Component counts per piece of equipment were those used in the GHG Inventory and GHGRP, which were derived the EPA/GRI study and 40 CFR, part 98, subpart W tables, were then used to determine the total number of fugitive components (valves, connectors, OELs, and PRVs) at each of these sites. A description of the data and methodology for determining fugitive emissions for these model plants are discussed in the following sections.

4.2.2 Oil and Gas Production Well Sites

Oil and natural gas production practices and equipment vary from site-to-site. Some production sites may include only a single wellhead that is extracting oil or natural gas from the ground, while other sites may include multiple wellheads attached to a well pad. A well site is a site where the production, extraction, recovery, lifting, stabilization, separation and/or treating of petroleum and/or natural gas (including condensate) occurs. These sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) that have associated components that may be sources of fugitive emissions associated with these operations. A well site can serve one well on a pad or multiple wells on a pad. Therefore, the number of components with potential for fugitive emissions can vary depending on the number of wells at the site.

Baseline model plant emissions for the natural gas and oil production well sites were calculated using the fugitive emissions equipment counts from GHG Inventory, derived from GHGRP, EPA/GRI,

³³ U.S. EPA. *Oil and Natural Gas Sector Leaks*, OAQPS. Research Triangle Park, NC. April 2014. Available at <http://www.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf>.

³⁴ The draft 2016 GHG Inventory was the most recent data available at the time of this analysis. The 2016 GHG Inventory was finalized April 15, 2016 with the same data that was used in the public review draft. Therefore, this analysis is consistent with the most recent final GHG Inventory.

and 40 CFR part 98, subpart W tables as described above, and the component oil and natural gas production emission factors from AP-42³⁵. Annual emissions were calculated assuming 8,760 hours of operation each year. The emissions factors are provided for total organic compounds (TOC) and include non-VOCs such as methane and ethane. The emission factors used to estimate the emissions from the production segment (e.g., oil production well sites and natural gas production well sites) are presented in Table 4-1. The emission factors in Table 4-1 are also used to calculate fugitive emissions from gathering and boosting stations.

Table 4-1. Oil and Gas Production Operations Average TOC Emissions Factors

Component Type	Component Service	Emission Factor ^a (kg/hr/source)
Valves	Gas	4.5E-03
Flanges	Gas	3.9E-04
Connectors	Gas	2.0E-04
OEL	Gas	2.0E-03
PRV	Gas	8.8E-03

a. Data Source: EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)

4.2.2.1 Proposed Rule Well Site Model Plant

A model plant for natural gas and oil well sites was developed using the average number of wells associated with a well site using data from the DrillingInfo HPDI® database³⁶. The analysis, described in the TSD for the proposed rule, determined that the national average of wells per well site was 1.81, and was rounded to 2.0 wells per well site for the model plant fugitive analysis for both natural gas production and oil production well sites.

For the proposed rule, average equipment count per well data from the EPA/GRI document for natural gas production well sites and GHG Inventory for oil production well sites were used to determine the number of production equipment located at a well site. The average equipment count per well for each of the equipment types were multiplied by the average number of wells at a well site (2) and then rounded up to the nearest integer.

The types of production equipment located at a natural gas well site includes: gas wellheads, separators, meters/piping, in-line heaters, and dehydrators. The types of components that are associated

³⁵ U.S. EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)

³⁶ Drilling Information, Inc. 2011. *DI Desktop*. 2011 Production Information Database.

with this production equipment include: valves, connectors, OELs, and PRVs. Component counts for each of the production equipment items were calculated using the average component counts for onshore production equipment in the Eastern U.S and the Western U.S. from the EPA/GRI report. Fractions of components were rounded up to the nearest integer.

Baseline fugitive emissions for the proposed rule were calculated using the estimated component counts for the natural gas well site and the total organic compound (TOC) emission factors from AP-42. Annual emissions were calculated assuming 8,760 hours of operation each year. The TOC emissions were converted to methane and VOC using methane/TOC and VOC/TOC weight ratios as described in the 2011 Gas Composition Memorandum developed for the 2012 NSPS³⁷. For the proposed rule, the fugitive emissions for the natural gas production well site model plant were determined to be 4.54 tons per year of methane and 1.26 tons per year of VOC.

For oil well sites, data from the GHG Inventory, derived from GHGRP reported data, were used to estimate equipment counts for these sources. The types of oil well site equipment include: oil well heads, separators, headers and heater/treaters. Fugitive emissions components counts for these equipment types were estimated using component count data from Table W-1C of 40 CFR part 98, subpart W.

The estimated baseline fugitive emissions from oil well sites were calculated using the estimated component counts and the total organic compound (TOC) emission factors from AP-42. Annual emissions were calculated assuming 8,760 hours of operation each year. The TOC emissions were converted to methane and VOC using methane/TOC and VOC/TOC weight ratios in the gas composition memorandum. For the proposed rule, the fugitive emissions for the oil well site model plant were determined to be 1.09 tons per year of methane and 0.30 tons per year of VOC.

4.2.2.2 Final Rule Natural Gas Well Site Model Plant

During the comment period for the proposed rule, updated data on equipment counts per well (derived from GHGRP reported data) became available for 2013 (the most recent year of data available in the public review draft) from the draft 2016³⁸ GHG Inventory, and was used to revise the equipment

³⁷ Memorandum to Bruce Moore. U.S. EPA from Heather Brown, EC/R. "Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking". July 28, 2011.

³⁸ In the final 2016 GHG Inventory, the equipment counts per well are the same as those in the draft GHG inventory used in this analysis.

counts for the natural gas well sites. The average equipment count per well was multiplied by the average number of wells per well site (2) and rounded to the next highest integer. The updated equipment counts per natural gas well site were 2 separators, 3 meters/piping, 1 in-line heaters, and 1 dehydrators per well. In comparison to the model plant in the proposed rule TSD, the only change in equipment counts was for meters/piping which increased from 1 to 3. Average component counts for each piece of equipment were calculated using the average component counts for onshore production equipment in the Eastern U.S and the Western U.S. from the EPA/GRI study. The total number of fugitive emissions components was calculated by multiplying the rounded equipment counts by the component count per piece of equipment and rounding to the nearest integer. A summary of the fugitive emissions component counts for natural gas production well sites is presented in Table 4-2.

The baseline fugitive emissions for the natural gas well site model plant were calculated using the revised component counts for the natural gas well site model plant and the oil and natural gas production AP-42 TOC emission factors. Annual emissions were calculated assuming 8,760 hours of operation each year. The TOC emissions were converted to methane and VOC using methane/TOC and VOC/TOC weight ratios in the gas composition memorandum. The fugitive emissions for the natural gas well site model plant were determined to be 5.50 tons per year of methane and 1.53 tons per year of VOC and are provided in Table 4-3.

4.2.2.3 Final Rule Oil Well Site Model Plant

Comments on the proposed rules stated that methane emissions from oil well site model plants were underestimated. While some oil wells produce very little natural gas (oil wells with a gas-to-oil-ratio less than 300 standard cubic feet of gas per stock barrel of oil), other oil wells produce significant volumes of natural gas (oil wells with a gas-to-oil-ratio greater than 300 standard cubic feet of gas per stock barrel of oil). To address these types of oil wells, two model plants were developed to estimate fugitive emissions from oil well sites. The oil well site model plant developed for the proposed rule was used to define the oils wells with a gas-to-oil ratio less than 300 standard cubic feet of gas per stock barrel of oil (< 300 GOR). During the comment period for the proposed rule, updated data on equipment counts per well (derived from GHGRP reported data) became available for 2013 (the most recent year of data available in the public review draft) from the draft 2016³⁹ GHG Inventory, and was used to revise

³⁹ In the final 2016 GHG Inventory, the equipment counts per well are the same as those in the draft GHG inventory used in this analysis.

the equipment counts for the oil well sites. The equipment count for this model plant consists of 2 oil wellheads, 1 separator, 1 header, and 1 heater/treater. To develop the model plant for oil well sites with a gas-to-oil ratio greater than 300 standard cubic feet of gas per stock barrel of oil (> 300 GOR), three meters/piping were added to the equipment counts included for the < 300 GOR model plant to account for the handling of the natural gas from the well. Component counts for the oil well equipment (wellhead, separator, header, heater/treater) were obtained from Table W-1C of subpart W. The component counts for meters/piping were obtained from the average component counts for onshore production equipment in the Eastern U.S and the Western U.S. from the EPA/GRI study. The total number of fugitive emissions components was calculated by multiplying the rounded equipment counts by the component count per production equipment and rounding to the nearest integer. A summary of the fugitive emissions component counts for oil well site model plants are presented in Table 4-4.

Baseline model plant emissions for the oil well site model plants were calculated using the fugitive emissions component counts and the component oil and natural gas production emission factors from AP-42. Annual emissions were calculated assuming 8,760 hours of operation each year. The TOC emissions were converted to methane and VOC using methane/TOC and VOC/TOC weight ratios in the gas composition memorandum. The fugitive emissions for the < 300 GOR model plant were determined to be 1.23 tons per year of methane and 0.33 tons per year of VOC. The fugitive emissions for the > 300 GOR model plant were determined to be 2.75 tons per year of methane and 0.75 tons per year of VOC. A summary of the emissions are provided in Table 4-5.

Table 4-2. Average Fugitive Emissions Component Count for Natural Gas Well Site Model Plant

Production Equipment	Model Plant Equipment Counts	Average Component Count Per Unit of Equipment ^a				Average Component Count Per Model Plant			
		Valves	Connectors	OELs	PRVs	Valves	Connectors	OELs	PRVs
Gas Wellheads	2	9.5	37.0	0.7	0.0	19.0	74.0	1.4	0.0
Separators	2	21.6	68.5	3.7	1.2	43.2	137.0	7.4	2.4
Meters/Piping	3	12.9	47.8	0.5	0.5	38.7	143.4	1.5	1.5
In-Line Heaters	1	14.0	65.0	2.0	1.0	14.0	65.0	2.0	1.0
Dehydrators	1	24.0	90.0	2.0	2.0	24.0	90.0	2.0	2.0
Total						138.9	509.4	14.3	6.9
Rounded Total						139	510	15	7

a. Data Source: EPA/GRI, CH₄ Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

Table 4-3. Estimated Fugitive Emission Estimate for Natural Gas Well Site Model Plant

Natural Gas Well Site Model Plant Component	Model Plant Component Count ^a	Uncontrolled Emission Factor ^b (kg/hr/comp)	Uncontrolled Emissions (tpy)	
			Methane ^c	VOC ^d
Valves	139	0.0045	4.196	1.166
Connectors	510	0.0002	0.684	0.190
OELs	15	0.002	0.201	0.056
PRVs	7	0.0088	0.413	0.115
Total			5.50	1.53

a. Fugitive emissions component count values for model plant are based on a 2 wellhead pad and are rounded to the nearest integer.

b. TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.

c. Methane emissions calculated using 0.695 weight ratio for Methane/TOC obtained from gas composition memorandum.

d. VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from gas composition memorandum.

Table 4-4. Average Fugitive Emissions Component Count for Oil Well Site Model Plant

Production Equipment	Model Plant Production Equipment Counts	Average Component Count Per Unit of Production Equipment ^a					Average Component Count Per Model Plant				
		Valves	Flanges	Connectors	OELs	PRVs	Valves	Flanges	Connectors	OELs	PRVs
Oil Well Model Plant (< 300 GOR) ^a											
Oil Wellheads	2	5	10	4	0	1	10	20	8	0	2
Separators	1	6	12	10	0	0	6	12	10	0	0
Headers	1	5	10	4	0	0	5	10	4	0	0
Heater/Treaters	1	8	12	20	0	0	8	12	20	0	0
Total							29	54	42	0	2
Oil Well Model Plant (> 300 GOR) ^b											
Oil Wellheads	2	5	10	4	0	1	10	20	8	0	2
Separators	1	6	12	10	0	0	6	12	10	0	0
Headers	1	5	10	4	0	0	5	10	4	0	0
Heater/Treaters	1	8	12	20	0	0	8	12	20	0	0
Meters/Piping	3	12.9	0	47.8	0.5	0.5	39	0	144	2	2
Total							68	54	186	2	4

a. Oil well (<300 GOR) component counts obtained from Table W-1C of 40 CFR part 98, subpart W.

b. Oil well (>300 GOR) component counts from 40 CFR Part 98, subpart W, Table W-1C.

Table 4-5. Estimated Fugitive Emission Estimate for Oil Well Site Model Plant

Oil Well Site Model Plant Component	Model Plant Component Count ^a	Uncontrolled Emission Factor ^b (kg/hr/comp)	Uncontrolled Emissions (tpy)	
			Methane ^c	VOC ^d
Oil Well Model Plant (< 300 GOR)				
Valves	29	0.0045	0.876	0.243
Flanges	54	0.00039	0.185	0.039
Connectors	42	0.0002	0.056	0.016
OELs	0	0.002	0	0
PRVs	2	0.0088	0.118	0.033
Total			1.23	0.33
Oil Well Model Plant (> 300 GOR)				
Valves	68	0.0045	2.053	0.571
Flanges	54	0.00039	0.185	0.039
Connectors	186	0.0002	0.250	0.069
OELs	2	0.002	0.027	0.007
PRVs	4	0.0088	0.236	0.066
Total			2.75	0.75

a. Fugitive emissions component count values for model plant are based on a 2 wellhead pad and are rounded to the nearest integer.

b. TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.

c. Methane emissions calculated using 0.695 weight ratio for methane/TOC obtained from gas composition memorandum.

d. VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from gas composition memorandum.

4.2.3 Compressor Stations

The proposed rule TSD evaluated fugitive monitoring at three types of compressor stations; gathering and boosting stations, transmission stations and storage stations. The equipment associated with these compressor stations vary depending on the volume of natural gas that is transported and whether any treatment of the gas, such as the removal of water or hydrocarbons occurs. These sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) that have associated components (e.g., valves, connectors) that may be sources of fugitive emissions associated with these operations.

4.2.3.1 Proposed Rule Compressor Station Model Plant

For the proposed rule TSD, baseline model plant emissions for compressor stations were calculated using the fugitive emissions component counts from the EPA/GRI document and the component oil and natural gas production emission factors from AP-42 for gathering and boosting stations and EPA/GRI emission factors for transmission and storage stations. Annual emissions were calculated assuming 8,760 hours of operation each year. The AP-42 emission factors are provided for total organic compounds (TOC) and include non-VOCs such as methane and ethane. The emission factors used to estimate the new source emissions from the gathering and boosting stations are presented in Table 4-1. In the proposed rule TSD, the fugitive emissions from gathering and boosting stations were estimated to be 35.1 tons per year of methane and 9.77 tons per year of VOC. The model plant fugitive emissions for transmission stations were estimated to be 62.4 tons per year of methane and 1.73 tons per year of VOC, and 164.4 tons per year of methane and 4.55 tons per year of VOC for storage stations.

4.2.3.2 Final Rule Compressor Station Model Plant

Gathering and boosting stations are sites that collect oil and natural gas from well sites and direct them to the natural gas processing plants. These stations have similar production equipment (including separators, meters, piping, compressors, in-line heaters, dehydrators and other equipment) to well sites; however, they are not directly connected to the wellheads. The EPA/GRI document does not have specific equipment counts for the gathering and boosting segment, but does include equipment counts for gathering compressors within the oil and natural gas production data. To estimate the equipment at a gathering and boosting model plant, the weighted averages of equipment counts for the Eastern and Western U.S. data sets for onshore production equipment were calculated. The weighted averages of the data sets were determined to be 11 separators, 7 meters/piping, 5 gathering compressors, 7 in-line heaters, and 5 dehydrators. These average equipment counts were used to create the model plant for gathering and boosting stations. The components for gathering compressors were included in the model plant total counts, but the compressor seals were excluded. Compressor seals are addressed in Chapter 8 of this document. A summary of the fugitive emissions component counts for oil and gas gathering and boosting stations are presented in Table 4-6.

The proposed gathering and boosting model plant did not change from proposal. Therefore, the baseline emissions that are discussed in Section 4.2.3.1 remain the same for the final TSD and are summarized in Table 4-7. The emissions were used to estimate the potential emission reductions and cost of control of a fugitive emissions reduction program.

4.2.3.3 Final Rule Natural Gas Transmission and Storage Model Plant

Natural gas transmission and storage stations are facilities that use compressors to move natural gas at elevated pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage. In addition, transmission stations may include production equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compressors operated by natural gas processing facilities are included in the onshore natural gas processing segment and are excluded from this segment. The segments include fugitive emissions from components related to inlet and outlet pipelines, meter runs, dehydrators, and other piping located at the compressor building for transmission and storage stations, and injection/withdrawal components associated with the injection/withdrawal well piping at storage stations. This industry segment also includes emissions from compressor related components, but does not include emissions from compressor seals or site blowdown open-ended lines. The blowdown open-ended lines were included in the proposed rule TSD, but were determined, based on comments, to be a vent rather than a fugitive emission source. Therefore in this analysis, emissions from blowdown open-ended lines were removed from the component list and the associated emissions were not included in the total fugitive emissions from transmission and storage stations. For the other components at these facilities, fugitive emissions component counts and methane emission factors were obtained from the EPA/GRI study. A summary of the fugitive emissions component counts, component emission factors and baseline methane and VOC emissions for transmission and storage model plants are presented in Table 4-8. The average fugitive emissions for transmission stations were determined to be 40.4 tons per year of methane and 1.12 tons per year of VOC and 142.4 tons per year of methane and 3.94 tons per year of VOC for storage facilities. These emissions were used to estimate the potential emission reductions and cost of control of a fugitive emissions reduction program.

Table 4-6. Average Fugitive Emissions Component Count for Gathering and Boosting Station Model Plant

Production Equipment	Model Plant Production Equipment Counts	Average Component Count Per Unit of Production Equipment ^a				Average Component Count Per Model Plant			
		Valves	Connectors	OELs	PRVs	Valves	Connectors	OELs	PRVs
Separators	11	22	68	4	1	242	748	44	11
Meters/Piping	7	13	48	0	0	91	336	0	0
Gathering Compressors	5	71	175	3	4	355	875	15	20
In-Line Heaters	7	14	65	2	1	98	455	14	7
Dehydrators	5	24	90	2	2	120	450	10	10
Total						906	2,864	83	48
Rounded Total						906	2,864	83	48

a. Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

Table 4-7. Estimated Fugitive Emissions for Gathering and Boosting Station Model Plant

Gathering and Boosting Station Model Plant Component	Model Plant Component Count	Uncontrolled Emission Factor ^a (kg/hr/comp)	Uncontrolled Emissions (tpy)	
			Methane ^b	VOC ^c
Valves	906	0.0045	27.35	7.603
Connectors	2,864	0.0002	3.84	1.068
OELs	83	0.002	1.11	0.310
PRVs	48	0.0088	2.83	0.788
Total			35.1	9.77

a. TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.

b. Methane emissions calculated using 0.695 weight ratio for methane/TOC obtained from gas composition memorandum.

c. VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from gas composition memorandum.

Table 4-8. Estimated Fugitive Emissions for Natural Gas Transmission and Storage Model Plant

Component	Model Plant Component Count ^a	Component Methane Emission Factor ^a (Mscf/year/component)	Methane Emissions ^b (tpy)	VOC Emissions ^c (tpy)
Transmission Facility				
Valve	673	0.867	12.1	0.336
Control Valve	31	8	5.2	0.143
Connectors	3,068	0.147	9.4	0.260
OEL	51	11.2	11.9	0.329
PRV	14	6.2	1.8	0.050
Total			40.4	1.12
Storage Facility				
Valve	1,868	0.867	33.7	0.933
Connector	5,571	0.147	17.0	0.472
OEL	353	11.2	82.3	2.77
PRV	66	6.2	8.52	0.236
Valve (Inj/With)	30	0.918	0.57	0.016
Connector (Inj/With)	89	0.125	0.23	0.006
OEL (Inj/With)	7	0.237	0.03	0.001
PRV (Inj/With)	1	1.464	0.03	0.001
Total			142.4	3.94

a. Component counts and methane emission factors for non-compressor related components obtained from EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-17 and 4-24, June 1996. (EPA-600/R-96-080h)

b. Methane emissions calculated by multiplying the model plant component count by the component methane emission factor and converting to tons using the conversion factor 0.02082 tons methane/Mscf methane.

c. VOC emissions calculated using 0.0277 weight ratio for VOC/methane obtained from Gas Composition memorandum.

4.3 Control Techniques

4.3.1 Potential Control Techniques

The use of OGI and Method 21 to monitor and reduce fugitive emissions from well sites and compressor stations was evaluated in the TSD for the proposed rule. Based on this analysis, it was determined that semiannual monitoring using OGI was BSER for both well sites and compressor stations. The EPA received numerous comments on this BSER determination and re-evaluated the OGI option using updated information received during the comment period. The re-evaluation for the final rule is provided in the following sections.

4.3.2 Fugitive Emissions Detection and Repair with OGI

4.3.2.1 Description

The reduction of fugitive emissions from well sites and compressor stations (i.e., gathering and boosting stations, transmission stations, and storage facilities) involves the development of a fugitive emissions monitoring plan. Under this option, the final rule states that monitoring is conducted using OGI, and the company develops and implements a monitoring plan that covers the collection of fugitive emissions components at well sites or compressor stations within a company defined area. The monitoring plan would include inspection of the collection of all fugitive emissions components, such as connectors, open-ended lines/valves, pressure relief devices, closed vent systems, compressors, and thief hatches on controlled storage vessels. The plan would include provisions to repair or replace fugitive emissions components if evidence of fugitive emissions is discovered during the OGI survey (e.g., any visible emissions from a fugitive emissions component observed using OGI).

In order to estimate the cost of implementation of a monitoring and repair plan, the EPA needed to estimate the cost of repair, which is based on the number of components found to have fugitive emissions. Since OGI visualizes gaseous emissions using active or passive infrared imaging, the OGI the operator would not be able to determine the exact concentration or emission rate of the fugitive emissions; however, all visualized fugitive emissions would be required to be repaired. If a fugitive emissions component cannot be immediately repaired during the monitoring survey, the operator must repair or replace the component as soon as practicable, but no later than 30 days after detection of the fugitive emissions. For this resurvey, the operator may use OGI, Method 21 or the alternative screening procedures specified in section 8.3.3 of Method 21 to confirm that the component is no longer emitting fugitive emissions. When OGI is used for the resurvey, no visible emissions indicate that the fugitive emissions component has been repaired. When Method 21 is used for the resurvey, no detectable emissions (e.g., a concentration of less than 500 ppm above background) indicate that the fugitive emissions component has been repaired.

4.3.2.2 Emission Reduction Potential

Information in the white paper related to the potential emission reductions from OGI monitoring and repair varied from 40 to 99 percent. The data from these studies are based on the gathering of individual OGI surveys at various oil and natural gas segment sites. The variation in the percent reductions from these OGI surveys generally depended on whether large fugitive emission sources were found during the OGI survey and assumptions made by the authors. However, these studies in the white paper did not

provide information on the potential emission reductions from the implementation of an annual, semiannual, quarterly or monthly OGI monitoring and repair program. A report was found after the publication of the white paper from the Colorado Air Quality Control Commission⁴⁰ which estimated 40 percent reduction for annual OGI monitoring for well production tank batteries with an uncontrolled VOC emissions of greater than 6 tpy or less than or equal to 12 tpy (≥ 6 to ≤ 12 tpy), 60 percent reduction for quarterly OGI monitoring for well production tank batteries with an uncontrolled VOC emissions of greater than 12 tpy and less than or equal to 50 tpy (> 12 to ≤ 50 tpy), and 80 percent reduction for monthly OGI monitoring at well production tank batteries with an uncontrolled VOC emission greater than 50 tpy (> 50 tpy).

From the review of the studies in the white paper and the Colorado Economic Impact Analysis, the EPA expects the emission reductions from the implementation of an OGI monitoring and repair program to vary depending on the frequency of monitoring. As noted above, Colorado estimated that monthly monitoring would achieve 80 percent at well production tank batteries with an uncontrolled VOC emission rate of greater than 50 tpy. We believe, based on our review of the studies, monthly monitoring should achieve much higher emission reductions. Based on the information in the studies and EPA's engineering judgement, the potential emission reduction percentages for the proposed rule were estimated to be 40 percent for annual monitoring, 60 percent for semiannual monitoring, and 80 percent for quarterly monitoring.

Data from the EPA Protocol document estimates monthly Method 21 monitoring to achieve 87 percent reductions at a leak definition of 10,000 ppm and 92 percent reductions at a leak definition of 500 ppm. Potential emissions reductions for annual, semiannual, and quarterly monitoring frequencies⁴¹ were calculated using the data from the EPA Protocol document. For quarterly monitoring, the Method 21 data from the EPA Protocol document estimates a 67 percent reduction at a leak definition of 10,000 ppm and an 83 percent reduction at a leak definition of 500 ppm. Using Method 21 data from the EPA Protocol document, we estimated the percent reductions from semiannual monitoring to be 55 percent at a leak definition of 10,000 ppm and 75 percent reduction at a leak definition of 500 ppm. The potential emission reduction percentages for annual monitoring were calculated to be 42 percent at a leak definition of 10,000 ppm and 68 percent at a leak definition of 500 ppm. The OGI camera is capable of viewing leaks at a 500

⁴⁰ Colorado Air Quality Control Commission, *Cost-Benefit Analysis for Proposed Revisions to Regulation Number 3 and 7 (5 CCR 1001-5 and 5 CCR 1001-9)*. February 7, 2014.

⁴¹ Memorandum from Bradley Nelson, EC/R to Jodi Howard, EPA/OAQPS/SPPD, Estimation of Potential Emission Reductions with the Implementation of a Method 21 Monitoring Program, April 25, 2016.

ppm level, and achieve similar reductions as a Method 21 monitoring program. Based on this information, we believe the expected emission reductions from an OGI monitoring and repair program falls somewhere in the 500 and 10,000 ppm range found in the Method 21 monitoring programs, but closer to the 500 ppm level.

A study performed by ICF⁴² using data from Subpart W, EPA/ GRI, City of Fort Worth Natural Gas Air Quality Study, UT Study - Methane Emissions in the Natural Gas Supply Chain: Production, UT Study - Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States Pneumatic Controllers and Jonah Energy LLC WCCA Spring Meeting Presentation determined that the Year 3 fugitive emissions reductions from a quarterly LDAR program to be 78 percent. The data provided in the study supports 40, 60, 80 percent emission reductions for annual, semi-annual and quarterly monitoring, respectively.

On the basis of the analysis and the data described here, it was concluded that an OGI monitoring program in combination with a repair program can reduce fugitive methane and VOC emissions from these segments by 40 percent on an annual frequency, 60 percent on a semiannual frequency and 80 percent on a quarterly frequency as well as minimize the loss of salable gas.

To be conservative, we performed a sensitivity analysis using the midpoint between the potential emissions reductions that were calculated for each of the Method 21 monitoring frequencies at leak definitions of 10,000 ppm and 500 ppm, which were determined to be 55, 65, and 75 percent for annual, semiannual and quarterly monitoring, respectively. We then compared the potential emissions reductions from 40, 60, 80 percent reductions with the Method 21 midpoint reduction percentages of 55, 65 and 75 and found that the annual methane and VOC emission reductions at each of the monitoring frequency intervals were comparable.⁴³

4.3.2.3 Cost Impacts

Costs for preparing an OGI fugitive emission monitoring and repair plan for a company defined area (i.e., field or district) were estimated using hourly estimates for each of the monitoring and repair plan elements. The costs are based on the following assumptions:

⁴² ICF International, Leak Detection and Repair Cost-Effectiveness Analysis, Prepared for Environmental Defense Fund, December 4, 2015, Revised May 2, 2016.

⁴³ See Emission Reduction Comparison - Well Sites.xls and Emission Reduction Comparison – Compressor Stations.xls in the docket for more information.

- Labor cost for each of the monitoring plan elements, such as reading the rule, was estimated to be \$57.80 per hour.
- Reading of the rule and instructions would take 1 person 4 hours to complete at a cost of \$231.
- Development of a fugitive emission monitoring plan would take 2.5 people a total of 60 hours to complete at a cost of \$3,468.
- Initial activities planning are estimated to take 2 people a total of 8 hours per person for each monitoring event. Cost for annual monitoring was estimated to be \$925 semiannual monitoring was estimated to be \$1,850 and quarterly monitoring \$3,699.
- Notification of compliance status was estimated to take 1 person 1 hour to complete at a cost of \$58 for compressor stations (i.e., gathering and boosting stations, transmission stations, and storage facilities). For companies that own and operate well sites, the cost notification of compliance status was estimated to be \$58 per well site for each company defined area, which is estimated to operate 22 well sites within the defined area for a total of \$1,272.
- Cost of a Method 21 Monitoring Device of \$10,800.
- Costs for implementing a fugitive emission monitoring plan for a company defined area (i.e., field or district) were estimated for each of the monitoring and repair elements. The costs are based on the following assumptions:
 - Subsequent activities planning are estimated to take 2 people a total of 8 hours per person to complete at a cost of \$925 per monitoring event. For oil and natural gas production well sites, this cost was divided among the total number of well sites owned in a company defined area, which was assumed to be 22. The cost per well site was estimated to be \$42 per monitoring event.
 - The cost for OGI monitoring using an outside contractor was assumed to be \$600 for a well site and \$2,300 for a compressor station.⁴⁴
 - Annual repair costs were estimated to be \$299 per monitoring event for well sites, \$3,436 per monitoring event for gathering and boosting stations, \$3,361 per monitoring event for transmission stations, and \$6,946 per monitoring event for storage facilities. These costs were estimated assuming that 1.18 percent of the components are found to leak⁴⁵ during monitoring and 75 percent are repaired online and 25 percent are repaired offline.

⁴⁴ Costs for contractor based OGI monitoring obtained from the Carbon Limits report.

⁴⁵ The assumption of 1.18% leak rate for OGI monitoring was obtained from Table 5 of the Uniform Standards memorandum. The 1.18% value is the baseline leak frequency for valves in gas/vapor service. None of the other baseline frequencies in this table were used because the equipment are in liquid service (e.g., pumps LL, valve LL, agitators LL). There is no information

- Costs to resurvey the repaired components that could not be fixed during the initial survey using a Method 21 device was estimated using a resurvey time of 5 minutes per leak at a cost of \$58 per hour. This assumes the company is able to perform the resurvey without retaining contractors. The capital costs include the cost of Method 21 instrumentation (estimated to be \$10,800⁴⁶). For compressor stations, the cost to resurvey repaired components was estimated to be \$2.00 per component.
- Preparation of annual reports was estimated to take 1 person a total of 4 hours to complete at a cost of \$231.

The initial setup cost or capital cost for oil and natural gas well sites was calculated by summing up the costs for reading the rule, development of fugitive emissions monitoring plan, initial activities planning, notification of initial compliance status, and purchase of a Method 21 instrumentation. The total capital cost of these activities was calculated to be \$17,620 per company defined areas for semiannual monitoring and \$19,470 per company define areas for quarterly monitoring. Assuming that each company owns and operates 22 well sites within a company defined area⁴⁷, the capital cost per well site was estimated to be \$759 for annual monitoring, \$801 for semiannual monitoring and \$885 for quarterly monitoring. For compressor stations (gathering and boosting stations, transmission stations and storage facilities) the capital cost for reading the rule, development of fugitive emissions monitoring plan, initial activities planning notification of initial compliance status, and purchase of a Method 21 instrumentation was calculated to be \$16,407 per facility. For gathering and boosting stations, this capital cost was assumed to be shared with other gathering and boosting stations within the company defined area. These stations are estimated to be approximately 70 miles apart. Therefore, within a 210 mile radius of a central location, there would be an estimated 7 gathering and boosting stations, and the capital cost of each of these stations was estimated to be \$2,393.

For all oil and natural gas segments, the annual cost includes; subsequent activities planning, OGI survey, cost of repair of fugitive emissions found, resurvey of repaired components, preparation and

on the number of leaks located at uncontrolled facilities, only average percentages of the total number of components at a facility. Therefore, our methodology was to use the 1.18% leak frequency value from the Uniform Standards memorandum and apply that value to the total number of components at the oil and natural gas model plant. (Uniform Standards Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA-HQ-OAR-2002-0037-0180).

⁴⁶ Average of subsequent monitoring costs in Table 13 from the Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA-HQ-OAR-2002-0037-0180

⁴⁷ The number of well sites owned and operated by companies was calculated using data from the Fort Worth study.

submittal of an annual report, and the amortized capital cost over 8 years at 7 percent interest. For our analysis the EPA calculated the annual cost for annual, semiannual and quarterly OGI surveys. The OGI monitoring cost memorandum⁴⁸ present the analyses for other costing methodologies, including a company-based OGI monitoring program and an OGI program using cost methodologies developed for the Colorado fugitive leak program to estimate the annual cost of implementing an OGI monitoring and repair program for oil and natural gas well sites, gathering and boosting, transmission and storage compressor stations for the respective OGI monitoring frequencies.

The cost per ton of emissions reduced was calculated using two separate methods. The first method allocated all of the costs to one pollutant and zero to the other (single-pollutant approach) using representative unit costs for each control option. The second method allocates the annual cost among the pollutants (multi-pollutant approach) that a given technology reduced (i.e., GHG (in the form of limiting methane emissions) and VOC). This proration was based on estimates of the percentage reduction expected for each pollutant. In the case of fugitives, the percent reductions for methane and VOC emissions are equal; and therefore the proration of the annual cost was divided equally and applied to the methane and VOC reductions.

Based on estimated emissions reductions and the estimated cost for implementing an OGI fugitive emissions monitoring and repair program at the affected facilities, the EPA calculated a cost of control for methane and VOC for the various options for oil and natural gas production well sites, gathering and boosting, and transmission and storage compressor stations. The EPA then calculated the cost of control of well sites and compressor stations using the weighted average cost of control for all well sites and all compressor stations (i.e., gathering and boosting, transmission and storage). Table 4-9, 4-10 and 4-11 presents a summary of the cost of control for methane and VOC for the three OGI monitoring frequency options (i.e., annual, semiannual and quarterly, respectively) based on the single-pollutant method. Tables 4-12, 4-13 and 4-14 present a summary of the capital and annual costs, and the cost of control for methane and VOC using the multi-pollutant method (i.e., 50 percent of the cost attributed to methane and 50 percent of the cost attributed to VOC).

⁴⁸ Memorandum from Bradley Nelson, EC/R to Jodi Howard, EPA, Evaluation of Cost methodologies for OGI Monitoring, April 6, 2016.

4.3.2.4 Secondary Impacts

No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of fugitive emissions components. There are some emissions that would be generated by the OGI camera monitoring contractors with respect to driving to and from the site for the fugitive emissions survey. Using AP-42 mobile emission factors⁴⁹ and assuming a distance of 70 miles to the well site or compressor station, the emissions generated from semiannual monitoring at a well site (140 miles to and from the well site twice a year) is estimated to be 0.35 pounds per year (lb/yr) of hydrocarbons, 6.0 lb/yr of carbon monoxide (CO) and 0.40 lb/yr of nitrogen dioxides (NO_x). The emissions generated from quarterly monitoring at a compressor station (140 miles to and from the compressor station four times a year) is estimated to be 0.70 lb/yr of hydrocarbons, 12.0 lb/yr of CO and 0.80 lb/yr of NO_x.

⁴⁹ AP-42: Compilation of Air Pollutant Emission Factors. Highway Vehicles, Light-Duty Gasoline Truck I, Model Year 1998+, 50,000 miles. <https://www3.epa.gov/otaq/ap42.htm#highway>

Table 4-9. Summary of the Model Plant Cost of Control for Annual OGI Monitoring Option – Single Pollutant⁵⁰

Model Plant	Annual Emission Reductions ^a (tpy)		Capital Cost ^b (\$)	Annual Cost (\$/year)		Cost of Control (without savings) (\$/ton)		Cost of Control (with saving) ^c (\$/ton)	
	CH ₄	VOC		without savings	with savings	CH ₄	VOC	CH ₄	VOC
Natural Gas Well Site ^d	2.20	0.61	\$759	\$1,318	\$809	\$600	\$2,158	\$368	\$1,324
Oil Well Site (GOR < 300) ^d	0.49	0.13	\$759	\$1,318	\$1,204	\$2,670	\$9,953	\$2,438	\$9,089
Oil Well Site (GOR > 300 GOR) ^d	1.10	0.30	\$759	\$1,318	\$1,063	\$1,198	\$4,380	\$967	\$3,533
Well Site Program Weighted Average ^h						\$1,224	\$4,464	\$993	\$3,619
Gathering & Boosting Station ^e	14.1	3.91	\$2,393	\$7,777	\$7,777	\$553	\$1,990	\$553	\$1,990
Transmission Station ^f	16.2	0.45	\$16,407	\$10,117	\$10,117	\$626	\$22,626	\$626	\$22,626
Storage Facility ^g	57.0	1.58	\$16,407	\$13,798	\$13,798	\$242	\$8,751	\$242	\$8,751
Compressor Stations Program Weighted Average ^h						\$541	\$3,098	\$541	\$3,098

a. Assumes 40% reduction with the implementation of annual IR camera monitoring.

b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program divided between an average of 22 well sites per company district. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between 7 stations within a company defined area. The capital cost for transmission and storage segments includes the cost of implementing the monitoring program.

c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

d. Annual cost for well sites includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7% interest.

e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7% interest.

f. Annual cost for transmission station includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7% interest.

g. Annual cost for storage facilities includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7% interest.

h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.

Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

⁵⁰ As explained earlier, this control option simultaneously reduces both methane (which is being evaluated for controlling the pollutant GHG) and VOC. Under the single pollutant approach, all costs are attributed to one pollutant and zero to the other. For simplicity, the table presents the cost per ton of the assigned pollutant; the table does not present the cost per ton of the one that is assigned zero cost because it is always zero.

Table 4-10. Summary of the Model Plant Cost of Control for the Semiannual OGI Monitoring Option – Single Pollutant⁵¹

Model Plant	Annual Emission Reductions ^a (tpy)		Capital Cost ^b (\$)	Annual Cost (\$/year)		Cost of Control (without savings) (\$/ton)		Cost of Control (with saving) ^c (\$/ton)	
	CH ₄	VOC		without savings	with savings	CH ₄	VOC	CH ₄	VOC
Natural Gas Production Well Site ^d	3.3	0.917	\$801	\$2,285	\$1,521	\$693	\$2,494	\$461	\$1,660
Oil Well Sites (GOR < 300) ^d	0.74	0.199	\$801	\$2,285	\$2,114	\$3,085	\$11,503	\$2,854	\$10,639
Oil Well Site (GOR > 300 GOR) ^d	1.65	0.451	\$801	\$2,285	\$1,903	\$1,385	\$5,062	\$1,153	\$4,215
Well Site Program Weighted Average ^h						\$1,415	\$5,160	\$1,183	\$4,314
Gathering & Boosting Station ^e	21.1	5.86	\$2,393	\$13,534	\$13,534	\$642	\$2,309	\$642	\$2,309
Transmission Station ^f	24.2	0.67	\$16,407	\$15,868	\$15,868	\$655	\$23,659	\$655	\$23,659
Storage Facility ^g	85.5	2.37	\$16,407	\$23,230	\$23,230	\$272	\$9,822	\$272	\$9,822
Compressor Stations Program Weighted Average ^h						\$625	\$3,480	\$625	\$3,480

a. Assumes 60% reduction with the implementation of semiannual IR camera monitoring.

b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program divided between an average of 22 well sites per company district. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between 7 stations within a company defined area. The capital cost for transmission and storage segments includes the cost of implementing the monitoring program.

c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

d. Annual cost for well sites includes annual monitoring and repair cost of \$2,151 and amortization of the capital cost over 8 years at 7% interest.

e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of \$13,133 and amortization of the capital cost over 8 years at 7% interest.

f. Annual cost for transmission station includes annual monitoring and repair cost of \$13,120 and amortization of the capital cost over 8 years at 7% interest.

g. Annual cost for storage facilities includes annual monitoring and repair cost of \$20,482 and amortization of the capital cost over 8 years at 7% interest.

h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.

Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

⁵¹ *Ibid.*

Table 4-11. Summary of the Model Plant Cost of Control for the Quarterly OGI Monitoring Option -Single-Pollutant⁵²

Model Plant	Annual Emission Reductions ^a (tpy)		Capital Cost ^b (\$)	Annual Cost (\$/year)		Cost of Control (without savings) (\$/ton)		Cost of Control (with saving) ^c (\$/ton)	
	CH ₄	VOC		without savings	with savings	CH ₄	VOC	CH ₄	VOC
Natural Gas Production Well Site ^d	4.4	1.222	\$885	\$4,220	\$3,201	\$960	\$3,453	\$728	\$2,619
Oil Well Sites (GOR < 300) ^d	0.99	0.265	\$885	\$4,220	\$3,991	\$4,272	\$15,929	\$4,041	\$15,064
Oil Well Site (GOR > 300 GOR) ^d	2.20	0.602	\$885	\$4,220	\$3,710	\$1,918	\$7,010	\$1,686	\$6,163
Well Site Program Weighted Average ^h						\$1,960	\$7,145	\$1,728	\$6,299
Gathering & Boosting Station ^e	28.1	7.81	\$2,393	\$25,049	\$25,049	\$891	\$3,205	\$891	\$3,205
Transmission Station ^f	32.3	0.89	\$16,407	\$27,369	\$27,369	\$847	\$30,606	\$847	\$30,606
Storage Facility ^g	114.0	3.15	\$16,407	\$42,093	\$42,093	\$369	\$13,348	\$369	\$13,348
Compressor Stations Program Weighted Average ^h						\$864	\$4,732	\$864	\$4,732

a. Assumes 80% reduction with the implementation of quarterly IR camera monitoring.

b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of \$19,470 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between 7 stations within a company defined area. The capital cost for the transmission and storage segments includes the cost of implementing the monitoring program of \$16,407.

c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

d. Annual cost for well sites includes annual monitoring and repair cost of \$4,071 and amortization of the capital cost over 8 years at 7% interest.

e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of \$24,649 and amortization of the capital cost over 8 years at 7% interest.

f. Annual cost for transmission station includes annual monitoring and repair cost of \$24,622 and amortization of the capital cost over 8 years at 7% interest.

g. Annual cost for storage facilities includes annual monitoring and repair cost of \$39,345 and amortization of the capital cost over 8 years at 7% interest.

h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.

Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

⁵² Ibid.

Table 4-12. Summary of the Model Plant Cost of Control for the Annual OGI Monitoring Option - Multi-Pollutant Method

Model Plant	Annual Emission Reductions ^a (tpy)		Capital Cost ^b (\$)	Annual Cost (\$/year)		Cost of Control (without savings) (\$/ton)		Cost of Control (with saving) ^c (\$/ton)	
	CH ₄	VOC		without savings	with savings	CH ₄	VOC	CH ₄	VOC
Natural Gas Production Well Site ^d	2.20	0.61	\$759	\$1,318	\$809	\$300	\$1,079	\$184	\$662
Oil Well Sites (GOR < 300) ^d	0.49	0.13	\$759	\$1,318	\$1,204	\$1,335	\$4,977	\$1,219	\$4,545
Oil Well Site (GOR > 300 GOR) ^d	1.10	0.30	\$759	\$1,318	\$1,063	\$599	\$2,190	\$483	\$1,767
Well Site Program Weighted Average ^h						\$612	\$2,232	\$496	\$1,810
Gathering & Boosting Station ^e	14.1	3.91	\$2,393	\$7,777	\$7,777	\$277	\$995	\$277	\$995
Transmission Station ^f	16.2	0.45	\$16,407	\$10,117	\$10,117	\$313	\$11,313	\$313	\$11,313
Storage Facility ^g	57.0	1.58	\$16,407	\$13,798	\$13,798	\$121	\$4,375	\$121	\$4,375
Compressor Stations Program Weighted Average ^h						\$271	\$1,549	\$271	\$1,549

a. Assumes 40% reduction with the implementation of annual IR camera monitoring.

b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of \$16,696 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was estimated to be \$16,753 divided between 7 stations within a company defined area. The capital cost for the transmission and storage segments includes the cost of implementing the monitoring program of \$16,407.

c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

d. Annual cost for well sites includes annual monitoring and repair cost of \$1,191 and amortization of the capital cost over 8 years at 7% interest.

e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of \$7,376 and amortization of the capital cost over 8 years at 7% interest.

f. Annual cost for transmission station includes annual monitoring and repair cost of \$7,369 and amortization of the capital cost over 8 years at 7% interest.

g. Annual cost for storage facilities includes annual monitoring and repair cost of \$11,050 and amortization of the capital cost over 8 years at 7% interest.

h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.

Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

Table 4-13. Summary of the Model Plant Cost of Control for the Semiannual OGI Monitoring Option - Multi-Pollutant Method

Model Plant	Annual Emission Reductions ^a (tpy)		Capital Cost ^b (\$)	Annual Cost (\$/year)		Cost of Control (without savings) (\$/ton)		Cost of Control (with saving) ^c (\$/ton)	
	CH ₄	VOC		without savings	with savings	CH ₄	VOC	CH ₄	VOC
Natural Gas Production Well Site ^d	3.3	0.917	\$801	\$2,285	\$1,521	\$347	\$1,247	\$231	\$830
Oil Well Sites (GOR < 300) ^d	0.74	0.199	\$801	\$2,285	\$2,114	\$1,543	\$5,752	\$1,427	\$5,319
Oil Well Site (GOR > 300 GOR) ^d	1.65	0.451	\$801	\$2,285	\$1,903	\$693	\$2,531	\$577	\$2,108
Well Site Program Weighted Average ^h						\$708	\$2,580	\$592	\$2,157
Gathering & Boosting Station ^e	21.1	5.86	\$2,393	\$13,534	\$13,534	\$321	\$1,155	\$321	\$1,155
Transmission Station ^f	24.2	0.67	\$16,407	\$15,868	\$15,868	\$327	\$11,829	\$327	\$11,829
Storage Facility ^g	85.5	2.37	\$16,407	\$23,230	\$23,230	\$136	\$4,911	\$136	\$4,911
Compressor Stations Program Weighted Average ^h						\$312	\$1,740	\$312	\$1,740

a. Assumes 60% reduction with the implementation of semiannual IR camera monitoring.

b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of \$17,620 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was estimated to be \$16,753 divided between 7 stations within a company defined area. The capital cost for the transmission and storage segments includes the cost of implementing the monitoring program of \$16,407.

c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

d. Annual cost for well sites includes annual monitoring and repair cost of \$2,151 and amortization of the capital cost over 8 years at 7% interest.

e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of \$13,133 and amortization of the capital cost over 8 years at 7% interest.

f. Annual cost for transmission station includes annual monitoring and repair cost of \$13,120 and amortization of the capital cost over 8 years at 7% interest.

g. Annual cost for storage facilities includes annual monitoring and repair cost of \$20,482 and amortization of the capital cost over 8 years at 7% interest.

h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.

Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

Table 4-14. Summary of the Model Plant Cost of Control for the Quarterly OGI Monitoring Option - Multi-Pollutant Method

Model Plant	Annual Emission Reductions ^a (tpy)		Capital Cost ^b (\$)	Annual Cost (\$/year)		Cost of Control (without savings) (\$/ton)		Cost of Control (with saving) ^c (\$/ton)	
	CH ₄	VOC		without savings	with savings	CH ₄	VOC	CH ₄	VOC
Natural Gas Production Well Sites ^d	4.40	1.222	\$885	\$4,220	\$3,201	\$480	\$1,726	\$364	\$1,310
Oil Well Sites (GOR < 300) ^d	0.99	0.265	\$885	\$4,220	\$3,991	\$2,136	\$7,964	\$2,020	\$7,532
Oil Well Sites (GOR > 300 GOR) ^d	2.20	0.602	\$885	\$4,220	\$3,710	\$959	\$3,505	\$843	\$3,081
Well Site Program Weighted Average ^b						\$980	\$3,572	\$864	\$3,150
Gathering & Boosting Station ^e	28.1	7.8	\$2,393	\$25,049	\$25,049	\$445	\$1,603	\$445	\$1,603
Transmission Station ^f	32.3	0.9	\$16,407	\$27,369	\$27,369	\$424	\$15,303	\$424	\$15,303
Storage Facility ^g	114.0	3.2	\$16,407	\$42,093	\$42,093	\$185	\$6,674	\$185	\$6,674
Compressor Stations Program Weighted Average ^h						\$432	\$2,366	\$432	\$2,366

a. Assumes 80% reduction with the implementation of quarterly IR camera monitoring.

b The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of \$19,470 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was estimated to be \$16,753 divided between 7 stations within a company defined area. The capital cost for the transmission and storage segments includes the cost of implementing the monitoring program of \$16,407.

c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

d. Annual cost for well sites includes annual monitoring and repair cost of \$4,071 and amortization of the capital cost over 8 years at 7% interest.

e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of \$24,649 and amortization of the capital cost over 8 years at 7% interest.

f. Annual cost for transmission station includes annual monitoring and repair cost of \$24,622 and amortization of the capital cost over 8 years at 7% interest.

g. Annual cost for storage facilities includes annual monitoring and repair cost of \$39,345 and amortization of the capital cost over 8 years at 7% interest.

h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.

Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

4.4 Regulatory Options

Monitoring of fugitive emissions was evaluated using OGI and Method 21 in the TSD for the proposed rule. For OGI, monitoring frequencies of annual, semiannual and quarterly were evaluated for well sites and compressor stations. Annual, semiannual and quartering monitoring was also evaluated for Method 21 at three different leak definitions; 500 ppm, 2,500 ppm and 10,000 ppm. Based on the results of these evaluations, semiannual monitoring using OGI was selected as BSER for well sites and compressor stations.

For this analysis, the OGI monitoring options were updated for the final rule using information received since proposal for the proposed rule. The OGI monitoring options include;

- Regulatory Option 1 – The implementation of an annual OGI fugitive emissions monitoring and repair program.
- Regulatory Option 2 - The implementation of a semiannual OGI fugitive emissions monitoring and repair program.
- Regulatory Option 3 - The implementation of a quarterly OGI fugitive emissions monitoring and repair program.

4.4.1 OGI Monitoring Options

As noted above, the EPA calculated a weighted average cost of control for well sites (which includes oil wells, oil wells with associated gas, and natural gas production well sites) and compressor stations (which includes gathering and boosting stations, transmission stations and storage facilities). For ease of review the EPA has summarized the cost of control for the options for well sites and compressor stations in Table 4-15.

Table 4-15. Summary of the Cost of Control for the OGI Monitoring Options⁵³

Option	Cost of Control (without gas savings)				Cost of Control (with gas savings)			
	Single-Pollutant (\$/ton)		Multi-Pollutant (\$/ton)		Single-Pollutant (\$/ton)		Multi-Pollutant (\$/ton)	
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Well Sites								
1 - Annual	\$1,224	\$4,464	\$612	\$2,232	\$993	\$3,619	\$496	\$1,810
2 - Semiannual	\$1,415	\$5,160	\$708	\$2,580	\$1,183	\$4,314	\$592	\$2,157
3 - Quarterly	\$1,960	\$7,145	\$980	\$3,572	\$1,728	\$6,299	\$864	\$3,150
Compressor Stations								
1 - Annual	\$504	\$2,225	\$252	\$1,112	\$272	\$1,201	\$136	\$601
2 - Semiannual	\$580	\$2,562	\$290	\$1,281	\$396	\$1,749	\$198	\$875
3 - Quarterly	\$802	\$3,540	\$401	\$1,770	\$618	\$2,728	\$309	\$1,364

4.4.2 EPA Method 21 as an Alternative to OGI Monitoring

4.4.2.1 Description

As an alternative to OGI monitoring, the EPA evaluated allowing the use of Method 21 to detect fugitive emissions from the collection of the fugitive emissions components at well sites and compressor stations to determine if the emissions reductions were equal to or greater than the emissions reductions achieved using OGI monitoring. As with OGI monitoring, emissions reductions vary based on the frequency of the monitoring of the components as well as the repair threshold. Based on comments received on the proposed rule, the EPA evaluated repair thresholds of 500 ppm and 10,000 for Method 21 fugitive emissions monitoring.

4.4.2.2 Emission Reduction Potential

The EPA based the emission reduction analysis on the method for estimating leak detection and repair (LDAR) control effectiveness from Chapter 5.3.1 of the Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017). Under this method, the control effectiveness is calculated using a stepwise approach that starts from the initial leak frequency and adds monitoring cycles until the leak frequency after monitoring reaches steady state. The difference between the initial leak rate and the final leak rate provides the control effectiveness for the fugitive emissions monitoring program. Other parameters included in the monitoring cycle calculations are the percentage of successfully repair

⁵³ *Ibid.*

components, the percentage of new leaks and the percentage of leaks that were repaired but have reoccurred. The EPA Protocol does not provide these data for oil and natural gas production; only for the Synthetic Organic Chemical Manufacturing Industry (SOCMI) and refineries. The refinery emissions data are provided in non-methane organic compound (NMOC) units, which would require assumed TOC and methane weight fractions to determine the TOC emission factors, whereas the SOCMI emissions data is already based on TOC. The assumed TOC and methane weight fractions would add another level of uncertainty to the emission reduction percentage calculations if the refinery data were used. Therefore, we determined that using the SOCMI data would provide the best estimate of potential fugitive emission reduction percentages for a typical Method 21 monitoring program, and would be comparable to the potential fugitive emission reductions for oil and gas production, if the other parameters were available for this segment. The potential emission reduction from the implementation of a Method 21 program was calculated using this SOCMI data. Table 4-16 provides a summary of the parameters used to calculate the monitoring cycles. An example of the methodology is provided in Chapter 5.3.2 of the EPA Protocol document. The SOCMI data in the EPA Protocol document only included occurrence rates for monthly and quarterly monitoring. To calculate annual and semiannual occurrence rates, a logarithmic equation was derived from the data points. Initial leak frequencies were calculated using the EPA Protocol average leak rate equations for 500 and 10,000 ppm gas valves (see Table 5-4) and the average SOCMI emission factor for gas valves of 0.00597 kilograms per hour per source (see Table 2-1) and solving for leak fraction. The initial leak frequencies can also be extrapolated using the lines in Figure 5-1 in the EPA Protocol document. The average leak fraction equation and calculated initial leak frequency are provided in Table 4-16.

Using the parameters in Table 4-16, the estimated emission reductions were calculated using the monitoring cycle approach in the EPA Protocol document. The leak frequency after monitoring reached steady state on the sixth monitoring cycle and the percent reduction was calculated. The results of the emission reductions are presented in Table 4-17.

Table 4-16. Parameters and Assumptions Used to Calculate Monitoring Cycles

Parameter	Parameter Value (500 ppm)	Parameter Value (10,000 ppm)
Occurrence Rate	5.46% Annual, 4.21% Semiannual, 2.97% Quarterly	5.46% Annual, 4.21% Semiannual, 2.97% Quarterly
Recurrence Rate	14%	14%
Unsuccessful Repair Rate	10%	10%
Initial Leak Frequency	13.53%	7.49%
Average Leak Rate Equation	$ALR = 0.044 * LF + 0.000017$	$ALR = 0.078 * LF + 0.00013$

Table 4-17. Percent Reduction in Emissions for EPA Method 21 Monitoring and Repair

Monitoring Frequency	Fugitive Percent Reduction		
	Method 21 Repair Threshold		OGI
	10,000 ppm	500 ppm	
Annual	42	68	40
Semiannual	55	75	60
Quarterly	67	83	80

As noted in Table 4-17 above, in all cases the percent reduction for the 500 parts per million Method 21 alternative is equal to or greater than the estimated OGI monitoring and repair percent reduction. The percent reduction for the 10,000 parts per million leak threshold was only greater than the OGI option for annual monitoring. Based on the estimated OGI monitoring model plant emission reductions (see Tables 4-9 through 4-14), Table 4-18 summarizes the estimated model plant emission reductions for the alternative Method 21 monitoring and repair option for 500 and 10,000 parts per million leak thresholds. For annual monitoring, both the Method 21 leak thresholds had higher emission reductions than the OGI monitoring option. Only the 500 parts per million leak threshold had emission reductions that were equal to or greater than the OGI monitoring option for semiannual and quarterly monitoring.

Table 4-18. Model Plant Emission Reductions for OGI and EPA Method 21 Monitoring and Repair

Affected Facility	OGI Monitoring (tpy)		Method 21 10,000 ppm (tpy) ^a		Method 21 500 ppm (tpy) ^a	
	Methane	VOC	Methane	VOC	Methane	VOC
Annual Monitoring						
Gas Well Sites	2.20	0.61	2.32	0.65	3.75	1.04
Oil Well Sites (GOR < 300)	0.49	0.13	0.52	0.14	0.84	0.23
Oil Well Sites (GOR > 300)	1.10	0.30	1.16	0.32	1.88	0.51
Gathering & Boosting	14.1	3.91	14.8	4.12	24.0	6.67
Transmission	16.2	0.45	17.0	0.47	27.6	0.76
Storage	57.0	1.58	60.1	1.66	97.3	2.69
Semiannual Monitoring						
Gas Well Sites	3.30	0.92	3.01	0.84	4.14	1.15
Oil Well Sites (GOR < 300)	0.74	0.20	0.68	0.18	0.93	0.25
Oil Well Sites (GOR > 300)	1.65	0.45	1.51	0.41	2.07	0.57
Gathering & Boosting	21.1	5.86	19.3	5.35	26.5	7.37
Transmission	24.2	0.67	22.1	0.61	30.5	0.84
Storage	85.5	2.37	78.1	2.16	107.4	2.97
Quarterly Monitoring						
Gas Well Sites	4.40	1.22	3.70	1.03	4.53	1.26
Oil Well Sites (GOR < 300)	0.99	0.26	0.83	0.22	1.02	0.27
Oil Well Sites (GOR > 300)	2.20	0.60	1.85	0.51	2.27	0.62
Gathering & Boosting	28.1	7.81	23.7	6.58	29.0	8.06
Transmission	32.3	0.89	27.2	0.75	33.3	0.92
Storage	114.0	3.15	96.0	2.66	117.5	3.25

a. Assumes baseline emissions shown in Tables 4-5 and 4-8 and percent reduction shown in Table 4-21.

5.0 PNEUMATIC CONTROLLERS

The natural gas industry uses a variety of process control devices to operate valves that regulate pressure, flow, temperature, and liquid levels. Most instrumentation and control equipment falls into one of three categories: (1) pneumatic; (2) electrical; or (3) mechanical. Of these, only pneumatic devices are direct sources of air emissions. Pneumatic controllers are used throughout the oil and natural gas sector as part of the instrumentation to control the position of valves.

The 2012 NSPS promulgated requirements for control of emissions from pneumatic controllers in the production and processing segments. During development of the 2012 NSPS amendments, methane and VOC emissions for these sources were estimated and included in the cost and impact analysis. See the 2011 NSPS TSD.

This chapter describes pneumatic controllers in the transmission and storage segment, including their function and associated emissions. Options available to reduce emissions from pneumatic controllers in the transmission and storage segment are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for pneumatic controllers.

5.1 Process Description

5.1.1 *Pneumatic Controllers*

For the purpose of this document, a pneumatic controller is a device that uses natural gas to transmit a process signal or condition pneumatically and that may also adjust a valve position based on that signal, with the same bleed gas and/or a supplemental supply of power gas. In the vast majority of applications, the natural gas industry uses pneumatic controllers that make use of readily available high-pressure natural gas to provide the required energy and control signals. In the transmission and storage segment, an estimated 84,000 pneumatic controllers actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities.⁵⁴

Pneumatic controllers are automated instruments used for maintaining a process condition such as liquid level, pressure, pressure differential, and temperature. In many situations across all segments of the oil and natural gas industry, pneumatic controllers make use of the available high-pressure natural gas to

⁵⁴ U.S. EPA. Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry. OAR: Natural Gas Star. Washington, DC. February 2004.

operate or control a valve. In these “gas-driven” pneumatic controllers, natural gas may be released with every valve movement and/or continuously from the valve control pilot. The rate at which the continuous release occurs is referred to as the bleed rate. Bleed rates are dependent on the design and operating characteristics of the device. Similar designs will have similar steady-state rates when operated under similar conditions. There are three basic designs: (1) continuous bleed devices are used to modulate flow, liquid level, or pressure, and gas is vented continuously at a rate that may vary over time; (2) intermittent controllers release gas only when they open or close a valve or as they throttle the gas flow; and (3) self-contained devices release gas to a downstream pipeline instead of to the atmosphere. This analysis assumes self-contained devices that release natural gas to a downstream pipeline instead of to the atmosphere have no emissions. Furthermore, it is recognized that “closed loop” systems are applicable only in instances with very low pressure⁵⁵ and may not be suitable to replace many applications of bleeding pneumatic devices. Therefore, these devices are not further discussed in this analysis.

Intermittent controllers are devices that only emit gas during actuation and do not have a continuous bleed rate. The actual amount of emissions from an intermittent controller is dependent on the amount of natural gas vented per actuation and how often it is actuated. Bleed devices also vent an additional volume of gas during actuation, in addition to the controller’s bleed stream. Since actuation emissions serve the controller’s functional purpose and can be highly variable, the emissions characterized for high-bleed and low-bleed devices in this analysis (as described in section 5.2.2) account for only the continuous flow of emissions (i.e., the bleed rate) and do not include emissions directly resulting from actuation. Intermittent controllers are assumed to have zero bleed emissions.⁵⁶ For most applications (but not all), intermittent controllers serve functionally different purposes than bleed devices. Therefore, because intermittent controllers are inherently low emitting sources and the total emissions are dependent on the applications in which they are used, the EPA did not include intermittent controllers in this analysis. This is consistent with the treatment of these controllers under the 2012 NSPS.

In addition, not all pneumatic controllers are gas driven. At sites with electrical service sufficient

⁵⁵ Memorandum to Bruce Moore, U.S. EPA from Denise Grubert, EC/R. Meeting Minutes from EPA Meeting with the API. October 2011.

⁵⁶ The EPA received comments indicating that in some cases intermittent controllers had continuous emissions, and low-bleed pneumatic controllers were observed to have emission rates that were 270 percent higher than the EPA’s emission factor for these devices, in some cases approaching the emission rate of high-bleed controllers. The EPA believes this is the result of malfunctioning controllers. The data the EPA have does not indicate that emissions from intermittent controllers are significant under normal operating conditions. The EPA are continuing to research this issue; however, the EPA do not believe additional requirements are warranted for such controllers based on the incidental, non-standard operation observed during these studies.

to power an instrument air compressor electrically powered pneumatic devices can be used. In addition, it may be possible to use electrically powered pneumatic devices at sites with electrical service. These “non-gas driven” pneumatic controllers can be mechanically operated or use sources of power other than pressurized natural gas, such as compressed “instrument air.” Because these devices are not gas driven, they do not directly release natural gas. However, electrically powered systems have energy impacts, with associated secondary impacts related to generation of the electrical power required to drive the instrument air compressor system. Instrument air systems are feasible only at oil and natural gas locations where the devices can be driven by compressed instrument air systems and have electrical service sufficient to power an air compressor. This analysis assumes that natural gas processing plants are the only facilities in the oil and natural gas source category likely to have electrical service sufficient to power an instrument air system, and that most existing gas processing plants use instrument air instead of gas-driven devices.⁵⁷

5.2 Emissions Data and Information

5.2.1 Summary of Major Studies and Emission

In the evaluation of the emissions from pneumatic controllers in the transmission and storage segment and the potential options available to reduce the emissions, the EPA consulted numerous studies and sources of information. Table 5-1 presents these studies and sources of information with an indication of the type of relevant information contained in each resource.

Table 5-1. Major Studies and Sources of Information Reviewed for Emissions and Activity Data

Report Name	Affiliation	Year of Report	Number of Devices	Emissions Information	Control Information
GHG Mandatory Reporting Rule and Technical Supporting Document ^a	EPA	2014	Nationwide	X	
Draft Inventory of GHG Emissions and Sinks: 1990-2014 ^b	EPA	2016	Nationwide/ Regional	X	
Methane Emissions from the Natural Gas Industry ^c	GRI/EPA	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry (draft) ^d	EPA	1996	Nationwide	X	

⁵⁷ Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices. Prepared for the GRI and EPA. EPA-600/R-96-080k. June 1996.

Report Name	Affiliation	Year of Report	Number of Devices	Emissions Information	Control Information
Methane Emissions from the Petroleum Industry ^e	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States ^f	Western Regional Air Partnership	2005	Regional	X	
Natural Gas STAR Program ^g	EPA	2000-2010	Other	X	X
Measurements of Methane Emissions from Natural Gas Production Sites in the U.S. ^h	Multiple Affiliations, Academic and Private	2013	Nationwide	X	
Determining Bleed Rates for Pneumatic Devices in British Columbia ⁱ	The Prasino Group	2013	British Columbia	X	
Air Pollutant Emissions from the Development, Production, and Processing of Marcellus Shale Natural Gas ^j	Carnegie Mellon University	2014	Regional (Marcellus Shale)	X	
Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries ^k	ICF International	2014	Nationwide	X	X

a. U.S. EPA. GHG Emissions Reporting From the Petroleum and Natural Gas Industry: Background TSD. Climate Change Division. Washington, DC. November 2010.

b. U.S. EPA. Public review draft of Inventory of U.S. Greenhouse Gas Emission and Sinks 1990-2014. Washington, DC.

c. Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 2: Technical Report. Prepared for the GRI and EPA. EPA-600/R-96-080b. June 1996, Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 3: General Methodology. Prepared for the GRI and EPA. EPA-600/R-96-080c. June 1996, Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 5: Activity Factors. Prepared for the GRI and EPA. EPA-600/R-96-080e. June 1996, and Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices. Prepared for the GRI and EPA. EPA-600/R-96-080k. June 1996.

d. Radian International LLC, Methane Emissions from the U.S. Petroleum Industry, draft report for the U.S. EPA, June 14, 1996.

e. ICF Consulting. Estimates of Methane Emissions from the U.S. Oil Industry. Prepared for the U.S. EPA. 1999.

f. ENVIRON International Corporation. Oil and Gas Emission Inventories for the WRAP. Prepared for Western Governors' Association. December 27, 2005.

g. U.S. EPA. Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry. OAR: Natural Gas Star. Washington, DC. February 2004.

h. Allen, David, T., et al. 2013. *Measurements of methane emissions at natural gas production sites in the United States*. Proceedings of the National Academy of Sciences (PNAS) 500 Fifth Street, NW NAS 340 Washington, DC 20001 USA. October 29, 2013. 6 pgs. (<http://www.pnas.org/content/early/2013/09/10/1304880110.full.pdf+html>).

i. U.S. EPA. Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air. OAR: Natural Gas Star. Washington, DC. February 2004.

j. U.S. EPA. PRO Fact Sheet No. 301. Convert Pneumatics to Mechanical Controls. OAR: Natural Gas Star. Washington, DC. September 2004.

k. Canadian Environmental Technology Advancement Corporation (CETAC)-WEST. Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Pneumatic Instruments. Prepared for the Canadian Association of Petroleum Producers. May 2008.

5.2.2 Representative Pneumatic Device Emissions

Continuous bleed pneumatic controllers can be classified into two types based on their emission rates: (1) high-bleed controllers and (2) low-bleed controllers. A controller is considered to be high-bleed when the continuous bleed emissions are in excess of 6 standard cubic feet per hour (scfh), while low-bleed devices bleed at a rate less than or equal to 6 scfh.⁵⁸

For this analysis, the EPA consulted information in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic devices, Subpart W of the GHG Reporting rule⁵⁹, the Inventory of GHG Emissions and Sinks, new studies, as well as pneumatic controller vendor information obtained during the development of the NSPS rulemaking. The data obtained from vendors included emission rates, costs, and any other pertinent information for each pneumatic device model (or model family). All pneumatic devices that a vendor offered were itemized and inquiries were made into the specifications of each device and whether it was applicable to oil and natural gas operations. High-bleed and low-bleed devices were differentiated using the 6 scfh threshold. Since publication of the white paper, additional data have become available on emissions from pneumatic controllers, including reporting year 2014 data from GHGRP, and new measurement data from Subramanian et al. 2015, and Allen et al. 2014. GHGRP reported methane emissions for 2014 are 197,387 tons CO₂ Eq.in transmission, and 111,354 tons CO₂ Eq.in storage. The 2016 GHG Inventory, with emissions data for 1990-2014, calculates that national methane emissions for pneumatic controllers are 694,801 tons CO₂Eq. in transmission and 734,112 tons CO₂Eq. in storage. In the Subramanian et al. 2015 data set, the average emission rate for pneumatic controllers in the transmission segment was 12.9 scfh, and the average emission rate for pneumatic controllers in the storage segment was 21.2 scfh. Information was not available on the fraction of high bleed versus low and intermittent bleed controllers in each population.

Although by definition, a low-bleed device can emit up to 6 scfh, through this vendor research, it was determined that the typical low-bleed device available currently on the market emits lower than the maximum rate allocated for the device type. Specifically, low-bleed devices on the market today have

⁵⁸ The classification of high-bleed and low-bleed devices originated from a report by Pacific Gas & Electric (PG&E) and the GRI in 1990 titled "Unaccounted for Gas Project Summary Volume." This classification was adopted for the October 1993 Report to Congress titled "Opportunities to Reduce Anthropogenic Methane Emissions in the United States". As described on page 2-16 of the report, "devices with emissions or 'bleed' rates of 0.1 to 0.5 cubic feet per minute are considered to be 'high-bleed' types (PG&E 1990)." This range of bleed rates is equivalent to 6 to 30 cubic feet per hour.

⁵⁹ Available at <http://www.epa.gov/ghgreporting/reporters/subpart/w.html>.

emissions from 0.2 scfh up to 5 scfh. Similarly, the available bleed rates for a high bleed device vary significantly from venting as low as 7 scfh to as high as 100 scfh.^{60,61} While the vendor data provides useful information on specific makes and models, it did not yield sufficient information about the prevalence of each model type in the population of devices; which is an important factor in developing a representative emission factor. For this analysis, the EPA determined that best available emissions rate estimates for pneumatic controllers are presented in Table W-3 of the GHG Mandatory Reporting Rule for the Oil and Natural Gas Industry (Subpart W).

The basic approach used for this analysis of emissions from pneumatic controllers was to first approximate the natural gas emissions from the average pneumatic controller type in the transmission and storage segment then estimate methane and VOC using a representative gas composition.⁶²

The specific ratios from the representative gas composition were 0.908 lbs of methane per pound of natural gas and 0.0277 lbs VOC per pound methane. Table 5-2 summarizes the estimated bleed emissions for a representative pneumatic controller by industry segment and device type.

Table 5-2. Average Bleed Emission Estimates per Pneumatic Controller in the Natural Gas Transmission and Storage Segment^{a, b}

High-Bleed (tpy)		Low-Bleed (tpy)	
Methane	VOC	Methane	VOC
3.013	0.083	0.227	0.00628

a. The conversion factor used in this analysis is 1,000 cubic feet (Mcf) of methane is equal to 0.0208 tons methane.

b. Natural gas transmission and storage emission factors for continuous bleed controllers were derived from Table W-1A of Subpart W.

5.3 Control Techniques

Several options to reduce emissions from pneumatic controllers were identified. Table 5-3 provides a summary of these options for reducing emissions from pneumatic controllers including: instrument air, non-gas driven controls, and enhanced maintenance. The use of instrument air systems, as discussed in the 2012 NSPS TSD⁶³, requires a constant source of electric power. Because electric power is not necessarily available at all transmission and storage affected facilities, the use of instrument air systems would not be practically feasible as a control for emissions from pneumatic controllers in this

⁶⁰ U.S. EPA. GHG Emissions Reporting From the Petroleum and Natural Gas Industry: Background TSD. Climate Change Division. Washington, DC. November 2010.

⁶¹ All rates are listed at an assumed supply gas pressure of 20 psig.

⁶² See footnote 3.

⁶³ See footnote 2.

industry segment. Likewise, because the mechanical systems identified for use in this industry would require, at minimum, a backup source of electric power, this option is also not considered to be practically feasible for use in controlling these pneumatic controller emissions. The enhanced maintenance option is considered to be too variable and costly as a viable option for control pneumatic controller emissions. Based on these concerns, further analyses of these options were not conducted.

Given the various applicability, cost of emission reductions and cost issues with the control options, the replacement of a high-bleed with a low-bleed device is the most likely scenario for reducing emissions from pneumatic controllers. This conclusion is consistent with and supported by requirements of States such as Colorado and Wyoming that require the use of low-bleed controllers in place of high-bleed controllers. Therefore, low-bleed controllers are further described in the following section, along with estimates of the impacts of their application for a representative device and nationwide basis.

As noted above, intermittent controllers are assumed to have zero bleed emissions. In addition, these controllers are assumed to not always be used in the same functional application as continuous bleed controllers. Therefore, intermittent controllers are not an appropriate option for control for all continuous bleed controllers. It is assumed intermittent, or no-bleed, controllers meet the definition of a low-bleed.

Table 5-3. Alternative Control Options for Pneumatic Controllers

Option	Description	Applicability/Effectiveness	Estimated Cost Range
Install Low Bleed Device in Place of High Bleed Device	Low-bleed devices provide the same functional control as a high-bleed device, while emitting less continuous bleed emissions.	Applicability may depend on the function of instrumentation for an individual device on whether the device is a level, pressure, or temperature controller.	Low-bleed devices are, on average, around \$165 more than high bleed versions.
Convert to Instrument Air ^a	Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic control. In this type of system, atmospheric air is compressed, stored in a tank, filtered and then dried for instrument use. For utility purposes such as small pneumatic pumps, gas compressor motor starters, pneumatic tools and sand blasting, air would not need to be dried. Instrument air conversion requires additional equipment to properly compress and control the pressured air. This equipment includes a compressor, power source, air dehydrator and air storage vessel.	Replacing natural gas with instrument air in pneumatic controls eliminates VOC emissions from bleeding pneumatics. These systems can achieve 100 percent reduction in emissions. It is most effective at facilities where there are a high concentration of pneumatic control valves and an operator present. Since the systems are powered by electric compressors, they require a constant source of electrical power or a back- up natural gas pneumatic device.	A complete cost analysis is provided in Section 5.4.2. System costs are dependent on size of compressor, power supply needs, labor and other equipment.
Mechanical and Solar Powered Systems in place of Bleed Device ^b	Mechanical controls operate using a simple design comprised of levers, hand wheels, springs and flow channels. The most common mechanical control device is the liquid-level float to the drain valve position with mechanical linkages. Electricity or small electrical motors (including solar powered) have been used to operate valves. Solar control systems are driven by solar power cells that actuate mechanical devices using electric power. As such, solar cells require some type of back-up power or storage to ensure reliability.	Application of mechanical controls is limited because the control must be located in close proximity to the process measurement. Mechanical systems are also incapable of handling larger flow fluctuations. Electric powered valves are only reliable with a constant supply of electricity. Overall, these options are applicable in niche areas but can achieve 100 percent reduction in emissions where applicable.	Depending on supply of power, costs can range from below \$1,000 to \$10,000 for entire systems.

Option	Description	Applicability/Effectiveness	Estimated Cost Range
Enhanced Maintenance ^c	Instrumentation in poor condition typically bleeds 5 to 10 scf per hour more than representative conditions due to worn seals, gaskets, diaphragms; nozzle corrosion or wear, or loose control tube fittings. This may not impact the operations but does increase emissions.	Enhanced maintenance to repair and maintain pneumatic devices periodically can reduce emissions. Proper methods of maintaining a device are highly variable and could incur significant costs.	Variable based on labor, time, and fuel required to travel to many remote locations.

a. U.S. EPA. Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air. OAR: Natural Gas Star. Washington, DC. February 2004.

b. U.S. EPA. PRO Fact Sheet No. 301. Convert Pneumatics to Mechanical Controls. OAR: Natural Gas Star. Washington, DC. September 2004.

c. CETAC-WEST. Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Pneumatic Instruments. Prepared for the Canadian Association of Petroleum Producers. May 2008.

5.3.1 Low-Bleed Controller Emission Reduction Potential

As discussed in the above sections, low-bleed controllers provide the same operational function as high-bleed controllers, but have lower continuous bleed emissions. As summarized in Table 5-4, the average achievable reduction in emissions per controller is estimated to be approximately 2.79 tons of methane and 0.077 tons of VOC. As noted in section 5.2, a low-bleed controller can emit up to 6 scfh, which is higher than the expected emissions from the typical low-bleed device currently available on the market.

Table 5-4. Estimated Annual Bleed Emission Reductions from Replacing a Representative High-Bleed Pneumatic Controller with a Representative Low-Bleed Pneumatic Controller in the Natural Gas Transmission and Storage Segment

Baseline Emission reductions - High-Bleed Replaced with Low-Bleed^a (tpy)	
Methane	VOC
2.79	0.077

a. Average emission reductions based on the typical emission rate from high-bleed and low-bleed controllers as listed in Table 5-2.

5.3.2 Emission Reduction Potential

There are certain situations in which replacing and retrofitting are not feasible, such as instances where a minimal response time is needed, cases where large valves require a high bleed rate to actuate, or a safety isolation valve is involved. Based on criteria provided by the Natural Gas STAR Program, it is assumed about 80 percent of high-bleed devices can be replaced with low-bleed devices throughout the transmission and storage segment.⁶⁴ This corresponds to 96 new high-bleed devices in the production segment (out of 120) that can be replaced with a new low-bleed alternative.

Applicability may depend on the function of instrumentation for an individual device such as whether the device is a level, pressure, or temperature controller. High-bleed pneumatic devices may not be applicable for replacement with low-bleed devices because a process condition may require a fast or precise control response so that it does not stray too far from the desired set point. A slower-acting controller could potentially result in damage to equipment and/or become a safety issue. An example of this is on a compressor where pneumatic devices may monitor the suction and discharge pressure and actuate a re-cycle when one or the other is out of the specified target range. Other scenarios for fast and

⁶⁴ See footnote 54.

precise control include transient (non-steady) situations where a gas flow rate may fluctuate widely or unpredictably. This situation requires a responsive high-bleed device to ensure that the gas flow can be controlled in all situations. Temperature and level controllers are typically present in control situations that are not prone to fluctuate as widely or where the fluctuation can be readily and safely accommodated by the equipment. Therefore, such processes can accommodate control from a low-bleed device, which is slower-acting and less precise.

5.3.3 Cost Impacts

As described in Section 5.2.2, costs were based on the vendor research as a result of updating and expanding upon the information given in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic devices.⁶⁵ As Table 5-5 indicates, the average cost for a low bleed pneumatic is \$2,471, while the average cost for a high bleed is \$2,698.⁶⁶ Thus, the incremental cost of installing a low-bleed device instead of a high-bleed device is on the order of \$227 per device. In order to analyze cost impacts, the incremental cost to install a low-bleed instead of a high-bleed was annualized for a 15-year period using a 7 percent interest rate. This equated to an annualized cost of around \$25 per low-bleed controller.

Table 5-5. Cost Projections for Representative Pneumatic Controllers^a

Controller Type	Minimum Cost (\$)	Maximum Cost (\$)	Average Cost (\$)	Low-Bleed Incremental Cost (\$)
High-Bleed Controller	\$387	\$7,398	\$2,471	\$227
Low-Bleed Controller	\$554	\$9,356	\$2,698	

a. Cost data from the 2012 NSPS was converted to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflator. During the development of the 2012 NSPS major pneumatic controller vendors were surveyed for costs, emission rates, and any other pertinent information that would give an accurate picture of the present industry.

Although monetary savings associated with additional gas captured exist, these savings were not estimated for the transmission and storage segment because it is assumed the owner of the pneumatic controller generally is not the owner of the natural gas. The cost per ton of emissions reduced was then calculated in two ways. The first method, the single pollutant approach, allocated all of the costs to one pollutant and zero to the other(s). The second method, the multipollutant approach, prorated costs among the pollutants that a given technology reduced (in this case GHG in the form of limiting methane emissions, and VOC). This proration was based on estimates of the percentage reduction expected for

⁶⁵ Ibid.

⁶⁶ Costs are estimated in 2012 U.S. Dollars.

each pollutant. Table 5-6 provides a summary of low-bleed pneumatic cost of control.

Table 5-6. Cost-of Control for Low-Bleed Pneumatic Controllers versus High Bleed Pneumatics for the Transmission and Storage Segment⁶⁷

Method	Incremental Capital Cost Per Unit ^a (\$)	Total Annual Cost Per Unit ^b (\$/year)	Emission reductions (tpy)		Cost of Control (\$/ton)	
			Methane	VOC	Methane	VOC
Single Pollutant Approach 100%	\$227	\$25	2.79	0.077	\$9	\$323
Multipollutant Approach 50/50	\$227	\$25	2.79	0.077	\$4	\$162

a. Incremental cost of a low bleed controller versus a high bleed controller as summarized in Table 6-7.

b. Annualized cost assumes a 7 percent interest rate over a 15-year equipment lifetime.

5.3.4 Secondary Impacts

Low-bleed pneumatic controllers are a replacement option for high-bleed devices that simply bleed less natural gas that would otherwise be emitted in the actuation of pneumatic valves. No wastes would be created, no wastewater generated, and no electricity required. Therefore, there are no secondary impacts expected from the use of low-bleed pneumatic devices.

5.4 Regulatory Options

EPA evaluated the following Regulatory alternatives for pneumatic controllers:

- Regulatory Option 1. Establish an emissions limit equal to 0 scfh.
- Regulatory Option 2. Establish an emissions limit equal to 6 scfh.

5.4.1 Evaluation of Regulatory Options

By establishing an emission limit of 0 scfh, facilities would most likely need to install instrument air systems to meet the threshold limit. Because facilities located in the transmission and storage segment might not always have sufficient electrical service to install an instrument air systems, this option would not be practically feasible in all situations. In addition, the cost of supplying electric power (which is highly variable) would need to be considered, which would likely render the cost of this control option unreasonable. Therefore, EPA rejected Regulatory Option 1 for facilities in the transmission and storage segment.

⁶⁷ As explained earlier, this control option simultaneously reduces both methane (which is being evaluated for controlling the pollutant GHG) and VOC. Under the single pollutant approach, all costs are attributed to one pollutant and zero to the other. For simplicity, the columns for the single pollutant approach present the cost per ton of the assigned pollutant; the table does not present the cost per ton of the one that is assigned zero cost because it is always zero.

Regulatory Option 2 would establish an emission limit equal to the maximum emissions allowed for a low-bleed device in the transmission and storage segment. This would most likely be met by the use of low-bleed controllers in place of a high-bleed controller, but allows flexibility in the chosen method of meeting the requirement. In the key instances related to pressure control that would disallow the use of a low-bleed device, specific monitoring and recordkeeping criteria would be required to ensure the device function dictates the precision of a high bleed device. Therefore, EPA is utilizing Regulatory Option 2 for facilities in the transmission and storage segment.

6.0 PNEUMATIC PUMPS

The natural gas industry uses a variety of pneumatic gas-powered pumps where there is no reliable electrical power to “control processing problems and protect equipment”.⁶⁸ Pneumatic pumps are “small positive displacement, reciprocating units used throughout the oil and natural gas production sector to inject precise amounts of chemicals into process streams [or for freeze protection glycol circulation].”⁶⁹ Most chemical injection pumps (CIPs) fall into two main types: diaphragm, generally for heat tracing or plunger/piston, generally for chemical and methanol injection. This chapter describes pneumatic pumps including their function and associated emissions. Options available to reduce emissions from pneumatic pumps are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for pneumatic pumps.

6.1 Process Description

In many situations across all segments of the oil and gas industry, pneumatic pumps make “use of gas pressure where electricity is not readily available.”⁷⁰ In the production segment, the supply gas is mostly produced natural gas, whereas in processing, the supply gas may be compressed air. In these gas-driven pneumatic pumps, characteristics that affect methane emissions include “the frequency of operation, the size of the unit, the supply gas pressure, and the inlet methane composition.”⁷¹

Pneumatic pumps are generally used for one of three purposes: glycol circulation in dehydrators, hot oil circulation for heat tracing/freeze protection, or chemical injection. Glycol dehydrator pumps “recover energy from the high-pressure rich glycol/gas mixture leaving the absorber and use that energy to pump the low-pressure lean glycol back into the absorber.”⁷² Diaphragm pumps are commonly used to circulate hot glycol or other heat-transfer fluids in tubing covered with insulation to prevent freezing in pipelines, vessels and tanks. CIPs, i.e. piston/plunger pumps or small diaphragm pumps, inject small desired amounts of chemicals such as methanol to prevent hydrate formation or corrosion inhibitors into process streams to regulate operations of a plant and protect the equipment.

⁶⁸ Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 13: Chemical Injection Pumps. Prepared for the GRI and EPA. EPA-600/R-96-080b. June 1996.

⁶⁹ Ibid.

⁷⁰ Ibid.

⁷¹ Ibid.

⁷² U.S. EPA OAQPS. Oil and Natural Gas Sector Pneumatic Devices. April 2014.

The piston and diaphragm pumps have two major components, a driver side and a motive side, which operate in the same manner but with different reciprocating mechanisms. Pressurized gas provides energy to the driver side of the pump, which operates a piston or flexible diaphragm to draw fluid into the pump. The motive side of the pump delivers the energy to the fluid being moved in order to discharge the fluid from the pump. The natural gas leaving the exhaust port of the pump is either directly discharged into the atmosphere or is recovered and used as a fuel gas or stripping gas.”⁷³

Chemical injection pumps work by allowing a fluid to flow into an enclosed cavity from a low-pressure source, trapping the fluid, and then forcing it out into a high-pressure receiver by decreasing the volume of the cavity. A complete reciprocating stroke includes two movements, referred to as an upward motion or suction stroke, and a downward motion or power stroke. During the suction stroke, the chemical is lifted through the suction check valve into the fluid cylinder. The suction check valve is forced open by the suction lift produced by the plunger and the head of the liquid being pumped. Simultaneously, the discharge check valve remains closed, thus allowing the chemical to remain in the fluid chamber. During the power stroke, the plunger assembly is forced downwards, immediately shutting off the suction check valve. Simultaneously, the chemical is displaced, forcing open the discharge check valve and allowing the fluid to be discharged. This complete movement represents one full stroke.⁷⁴

Typical chemicals injected in an oil or gas field are biocides, demulsifiers, clarifiers, corrosion inhibitors, scale inhibitors, hydrate inhibitors, paraffin dewaxers, surfactants, oxygen scavengers, and H₂S scavengers. These chemicals are normally injected at the wellhead and into gathering lines or at production separation facilities. Since the injection rates are typically small, the pumps are also small. They are often attached to barrels containing the chemical being injected.⁷⁵

Diaphragm pumps work by flexing the diaphragm out of the displacement chamber. When the diaphragm moves out, the volume of the pump chamber increases and causes the pressure within the chamber to decrease and draw in fluid. The inward stroke has the opposite effect, decreasing the volume and increasing the pressure of the chamber to move out fluid.⁷⁶

⁷³ Ibid.

⁷⁴ Ibid.

⁷⁵ Ibid.

⁷⁶ GlobalSpec. Diaphragm Pumps Information. Available at http://www.globalspec.com/learnmore/flow_transfer_control/pumps/diaphragm_pumps.

In addition, not all pneumatic pumps are gas-driven. These “non-natural-gas driven” pneumatic pumps can be mechanically operated or use sources of power other than pressurized natural gas, such as compressed “instrument air.” Because these devices are not natural gas-driven, they do not directly release natural gas or VOC emissions. However, these systems have other energy impacts, with associated secondary impacts related to generation of the electrical power required to drive the instrument air compressor system. Instrument air systems are feasible only at oil and natural gas locations where the devices can be driven by compressed instrument air systems and have electrical service sufficient and reliable enough to power an air control system. This analysis assumed that natural gas processing plants and natural gas transmission stations are the only facilities in the oil and natural gas source category highly likely to have electrical service sufficient to power an instrument air system, and that most existing gas processing plants use instrument air instead of gas-driven devices.⁷⁷ The application of electrical controls is further elaborated in Section 6.2.

6.1.1 Emissions Data and Information

In the evaluation of the emissions from pneumatic pumps and the potential options available to reduce these emissions, numerous studies were consulted. Table 6-1 lists these references with an indication of the type of relevant information contained in each study.

Table 6-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Number of Devices	Emissions Information	Control Information
GHG Mandatory Reporting Rule	EPA	2012	Nationwide	X	
Inventory of U.S. GHG Emissions and Sinks: 1990-2014	EPA	2016	Nationwide/ Regional	X	
Methane emissions from the Natural Gas Industry	GRI/EPA	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry	EPA	1999	Nationwide	X	
Natural Gas STAR Program	EPA	2012	Study Specific	X	X

⁷⁷ Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices. Prepared for the Gas Research Institute and Environmental Protection Agency. EPA-600/R-96-080k. June 1996.

6.1.1.1 Representative Pneumatic Pump Emissions

For this analysis, the EPA consulted information in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic pumps^{78,79}, Subpart W of the GHG Reporting rule⁸⁰, U.S. GHG Natural Gas and Petroleum Inventories (GHG Inventory)⁸¹, and U.S. EPA GRI Report⁸². Subpart W and GHG Inventory use the emission factors from the U.S. EPA GRI Report. Similarly, EPA determined that the best available emission factors for pneumatic pumps are presented in the U.S. EPA GRI Report. For the activity factor, EPA determined the best available data is the GHG Inventory. Since publication of the white paper, additional data have become available on emissions from pumps, including GHGRP 2014 reporting year data. In 2014, reported methane emissions from chemical injection pumps in the production segment were 3,037,798 tons of CO₂ Eq. In the Inventory of Greenhouse Gas Emissions and Sinks: 1990-2014, national methane emissions from chemical injection pumps for 2014 are around 8,034,400 tons of CO₂Eq.

The basic approach used for this analysis was to first approximate methane emissions from the average pneumatic pump in each industry segment and then estimate VOC and HAP using the gas composition as was determined for the NSPS.⁸³ The specific ratios from the gas composition used for this analysis were 0.278 lbs VOC per pound methane in the production and processing segments. Table 6-2 summarizes the estimated bleed emission factors for a representative pneumatic pump by industry segment.

⁷⁸ U.S. Environmental Protection Agency. Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air. Office of Air and Radiation: Natural Gas Star. Washington, DC. February 2004.

⁷⁹ U.S. Environmental Protection Agency. Pro Fact Sheet No. 301. Convert Pneumatics to Mechanical Controls. Office of Air and Radiation: Natural Gas Star. Washington, DC. September 2004.

⁸⁰ U.S. Environmental Protection Agency. Mandatory Reporting of Greenhouse Gases from Petroleum and Natural Gas Systems – Subpart W. Washington, DC. November 2010.

⁸¹ U.S. EPA. Inventory of U.S. Greenhouse Gas Inventory and Sinks. 1990 - 2012. Available at <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/archive.html>.

⁸² Gas Research Institute (GRI)/U.S. Environmental Protection Agency. Research and Development, Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps. June 1996 (EPA-600/R -96-080m).

⁸³ See footnote 3.

Table 6-2. Average Bleed Emission Estimates per Pneumatic Pump

Segment/Pump Type	Emission Factor (scf/hr) ^a	Emission factor (Mcf/year) ^b	Emission Factor (tpy) ^c	Emission Factor (tpy) ^d
	Natural Gas	Methane	Methane	VOC
<i>Production</i>				
Diaphragm	22.45	163	3.46	0.96
Piston	2.48	18	0.38	0.11
<i>Processing</i>				
Small Diaphragm	22.45	163	3.46	0.96
Medium Diaphragm	22.45	163	3.46	0.96
Large Diaphragm	22.45	163	3.46	0.96
Small Piston	2.48	18	0.38	0.11
Medium Piston	2.48	18	0.38	0.11
Large Piston	2.48	18	0.38	0.11

a. Data Source: EPA/GRI. Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps. June 1996 (EPA-600/R -96-080m), Sections 6.1 – Diaphragm Pumps and 6.2 – Piston Pumps. In the development of the emission factor, the GRI study incorporated a usage factor of 44% for diaphragm pumps and 40% for piston pumps.

b. Assumes 8760 hrs/yr and volumetric fraction of methane is 82.9% of natural gas in natural gas production and processing.

c. Assumes density of methane is 19.26 g/scf.

d. Assumes 0.27797 VOC content per pound of methane in natural gas production and processing.

6.2 Control Techniques

Gas-driven chemical pumps emit methane during normal operations. Depending on the type of pump, and the constraints of the location, companies can utilize a variety of technologies to reduce emissions. Table 6-3 provides a summary of these options for reducing emissions from gas-driven chemical pumps including: instrument air, solar, electricity, or routing emissions to a gas capture system or flare.

In situations where the replacement of gas-driven pumps with electric, solar and instrument air pumps is not possible, emissions can be captured via a vapor recovery unit (VRU), or sent to a combustion device. Emission control options for gas-driven pumps are described in the following section.

Table 6-3. Alternative Control Options for Gas-Driven Pumps

Option	Description	Applicability/Effectiveness	Estimated Cost Range
Convert to Solar Pumps	Solar power cells can generate electricity to power the pump. Solar cells can utilize a back-up power system to ensure reliability.	Solar powered pumps are only reliable in areas where the sun can power the pump reliably. These devices can result in 100 percent reduction in emissions where applicable.	Capital costs for converting to solar pumps is approximately \$2,300 per device
Convert to Electric Pumps	Electric pumps can be used where a reliable source of electricity is available at the facility.	Electric powered pumps are only reliable with a constant supply of electricity. Overall, this option is applicable in niche areas but can achieve 100 percent reduction in emissions where applicable.	Capital costs range between \$1,807 to \$5,352 plus electricity costs and an average annual maintenance cost of \$263 per device.
Convert to Instrument Air Error! Bookmark not defined.	Instrument air systems can be used by replacing compressed air for the gas in pumps. These systems include a compressor, electrical power source, air dehydrator (depending on the type of pump), and volume tank.	Instrument air systems reduce emissions by 100 percent by replacing natural gas with instrument air. This technology offers economies of scale, where it is more economical at facilities with more pneumatic pumps. The system requires a reliable source of electrical power.	A complete cost analysis is provided in Section 6.3.3 System costs are dependent on size of compressor, power supply needs, labor and other equipment.
Route Natural Gas to an Existing Control Device	Routing natural gas from a gas-driven pump entails piping to a control device inlet stream.	Routing natural gas pumps to a combustion device reduces VOC and methane emissions by 95 percent. Routing natural gas to a control device is an option when a control device with available capacity is present on site.	Capital costs will vary depending on the distance of pipeline necessary, but are approximately \$5,433 per device.
Route Natural Gas to Newly Installed Control Device	Routing natural gas from a gas-driven pump to a control device requires installation of a control device and piping between the pump and the control device.	Routing natural gas-driven pumps to a combustion control device typically reduces VOC and methane emissions by 95 percent. Routing natural gas to a control device is an option when utilities (i.e., electricity, water) needed to run the device are readily available.	Capital costs will be approximately \$48,500 with annual costs around \$104,000.
Route Natural Gas to Existing Gas Capture System	Routing natural gas from a gas-driven pump entails piping to a VRU.	Routing natural gas-driven pumps to a VRU reduces VOC and methane emissions through gas capture where emission reduction efficiencies are typically 95 percent. Routing natural gas	Capital costs will vary depending on the distance of pipeline necessary, but are estimated to be approximately \$5, 433 per device.

Option	Description	Applicability/Effectiveness	Estimated Cost Range
		to a VRU is applicable when an existing VRU with available capacity is present on site.	
Route Natural Gas to Newly Installed Gas Capture System	Routing natural gas from a gas-driven pump to a gas capture system requires the installation of a gas capture system such as a VRU and piping between the pump and the capture system. There must also be an onsite use for the captured gas such as a combustion engine; otherwise, a control device would be required.	Installing a VRU and sending natural gas from pumps results in emission reductions of approximately 95percent. This option is most effective at facilities with a large number of pumps, and other emission sources that can also be sent to the VRU.	Capital costs will be approximately \$36,000 with annual costs around \$7,500.

6.2.1 Solar Pumps

6.2.1.1 Emissions Reduction Potential

Solar pumps provide the same functionality as gas-driven pumps, and can be utilized at remote sites where a reliable source of electricity is not available. Solar-charged direct current (DC) pumps can handle a range of throughputs up to 100 gallons per day with maximum injection pressure around 3,000 pounds per square inch gage (psig) and have zero natural gas emissions. Replacing a natural gas-driven pump with a solar pump can result in 100 percent reduction in methane and VOC emissions. Therefore, based on the emissions from Table 6-2 above, the EPA estimates converting natural gas-driven chemical pumps to solar-powered pumps can reduce methane emissions by 3.46 tons per year per diaphragm pump and 0.38 tons per year per piston pump for all segments. Based on the gas composition for natural gas in the production segment, the EPA estimates that replacement of a natural gas-driven pump with a solar-powered pump will reduce VOC emissions by 0.96 tons per year per diaphragm pump and 0.11 tons per year per piston pump. Likewise, for the transmission and storage segment, the EPA estimates that replacement of a natural gas-driven pump with a solar-powered pump will reduce methane emissions by 3.46 tons per year per diaphragm pump and 0.38 tons per year per piston pump VOC emissions by 0.1 tons per year per diaphragm pump and 0.01 tons per year for a piston pump.

6.2.1.2 Effectiveness

Replacing a natural gas-driven pump with a solar pump can result in 100 percent reduction in methane and VOC emissions and is feasible in regions where there is sufficient sunlight to power the pump, and backup power is not required. Solar-powered pumps are typically low volume pumps that inject methanol or corrosion inhibitors into a well with typical volumes ranging from 6 to 8 gallons per day. In addition to low volume pumps, large volume pumps used to replace natural gas-assisted circulation pumps for glycol dehydrators can also be converted to solar.

6.2.1.3 Cost Impacts

The primary costs associated with conversion to solar pumps are the initial capital expenditures and annual maintenance costs which are typically lower than gas-driven pump maintenance costs. The cost being attributed to the replacement of pneumatic pumps with solar powered pumps includes the capital cost of replacing the pump with a solar powered pump and operating cost. The operating costs are estimated to be 10 percent of the capital costs. Based on Natural Gas STAR document, "PRO Fact Sheet:

Convert Natural Gas-Driven Chemical Pumps”⁸⁴, the cost for solar-powered electric pumps are approximately \$2,000 with solar panels having a lifespan of 15 years and electric motors lasting 5 years. The total capital cost, including installation and labor are \$2,227 (2012 dollars). The EPA estimates there would be no additional annual operating cost for solar pumps above and beyond that of ordinary field personnel duties. Annualized over the life of the pump at a 7 percent discount rate, the annualized cost of replacing a natural gas-driven pump with a solar pump is \$317. In addition, the use of electric pumps will have savings realized from the gas not released. The EPA estimates that each diaphragm pump replaced will save 197 Mcf per year of natural gas from being emitted and each piston pump will have a natural gas savings of 22 Mcf per year. The value of the natural gas saved based on \$4.00 per Mcf would be \$786 per year for diaphragm pumps and \$87 per year per piston pump.

6.2.1.4 Secondary Impacts

No secondary impacts from conversion to solar powered pumps are expected.

6.2.2 Electric Pumps

6.2.2.1 Emission Reduction Potential

Electric pumps also provide the same functionality as gas-driven pumps, and are only restricted by availability of a reliable source of electricity. Electric pumps have zero natural gas emissions, as summarized in Table 6-4, and converting gas-driven chemical pumps to an electric pump can reduce methane emissions by an estimated 3.46 tons per year per diaphragm pump and 0.38 tons per year per piston pump. Based on the gas composition for natural gas in the production segment, the EPA estimates that replacement of a pneumatic pump with an electric pump will reduce VOC emissions by 0.96 tons per year per diaphragm pump and 0.11 tons per year for a piston pump. Likewise, for the transmission and storage segment, the EPA estimates that replacement of a pneumatic pump with an electric pump will reduce methane emissions by an estimated 3.46 tons per year per diaphragm pump and 0.38 tons per year per piston pump and VOC emissions by 0.1 tons per year per diaphragm pump and 0.01 tons per year for a piston pump.

⁸⁴ U.S. EPA. PRO Fact Sheet No. 202. Convert Natural Gas-Driven Chemical Pumps. Available at <http://www.epa.gov/gasstar/documents/convertgasdrivenchemicalpumpstoinstrumentair.pdf>.

6.2.2.2 Effectiveness

Replacing a natural gas-driven pump with an electric pump can result in 100 percent reduction in emissions. However, use of electric pumps requires a sufficient and reliable source of electricity. These pumps are, therefore, more common at processing plants or large dehydration facilities that have access to reliable power.

6.2.2.3 Cost Impacts

The primary costs associated with converting natural gas-driven pumps to electric pumps are the initial capital expenditures, installation and ongoing operation and maintenance. Based on the Natural Gas STAR document, "PRO Fact Sheet: Convert Natural Gas-Driven Chemical Pumps,"⁸⁵ the cost of electric pumps to replace diaphragm pumps is \$4,647 and to replace a piston pump is \$1,819 in 2012 dollars depending on the horsepower of the unit.⁸⁶ The annual operating costs for the electric pumps is estimated to be \$293. Annualizing the capital cost over the life expectancy of the pump at a 7 percent discount rate, the annual cost for replacing a natural gas-driven pump with an electric pump is \$954 for diaphragm pump, and \$552 for a piston. In addition, the use of electric pumps will have savings realized from the gas not released. The EPA estimates that each diaphragm pump replaced will save 197 Mcf per year of natural gas from being emitted and each piston pump will save of 22 Mcf per year. The value of the natural gas saved based on \$4.00 per Mcf would be \$786 per year for diaphragm pumps and \$87 per year per piston pump.

6.2.2.4 Secondary Impacts

The secondary impacts from electric pumps are indirect, variable and dependent on the electrical supply used to power the compressor. No other secondary impacts are expected.

6.2.3 Instrument Air System

6.2.3.1 Process Description

Instrument air systems require a compressor, power source, dehydrator, and volume tank. The same natural gas-driven pumps can be used for natural gas and compressed air, without altering any of the parts of the pump, but instrument air eliminates the emissions of natural gas. All facilities that have access to a reliable source of electricity can install an instrument air system. A description of each of the

⁸⁵ Ibid.

⁸⁶ U.S. EPA. Lessons Learned. Replacing Gas-Assisted Glycol Pumps with Electric Pumps. Available online - http://www.epa.gov/gasstar/documents/ll_glycol_pumps3.pdf.

components as described in the Natural Gas STAR document, “PRO Fact Sheet: Convert Gas Pneumatic Controls to Instrument Air”:⁸⁷

- Compressors used for instrument air delivery are available in various types and sizes, from rotary screw (centrifugal) compressors to positive displacement (reciprocating piston) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system, and the typical bleed rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank. For reliability, a full spare compressor is normally installed.
- A critical component of the instrument air control system is the power source required to operate the compressor. Because high-pressure natural gas is abundant and readily available, gas pneumatic systems can run uninterrupted on a 24-hour, 7-day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and remote locations, however, a reliable source of electric power can be difficult to assure. In some instances, solar-powered battery-operated air compressors can be cost effective for remote locations, which reduce both methane emissions and energy consumption. Small natural gas powered fuel cells are also being developed.
- Dehydrators, or air dryers, are an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices.
- The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, without affecting the process control functions.

6.2.3.2 Emission Reduction Potential and Effectiveness

Instrument air eliminates all emissions from natural gas-driven pumps, but can only be used in locations with sufficient and reliable electrical power. Furthermore, instrument air systems are more

⁸⁷ See footnote 78.

economical and therefore more common at facilities with a high concentration of pneumatic devices and where an operator can ensure the system is properly functioning.⁸⁸ Because all emissions can be avoided by converting natural gas-driven chemical pumps to instrument air, methane emissions can be reduced by an estimated 3.46 tons per year per diaphragm pump and 0.38 tons per year per piston pump. Based on the gas composition for natural gas in the production segment, the EPA estimates that replacement of a pneumatic pump converted to instrument air will reduce VOC emissions by 0.96 tons per year per diaphragm pump and 0.11 tons per year for a piston pump. Likewise, for the transmission and storage segment, the EPA estimates that replacement of a pneumatic pump converted to instrument air will reduce methane emissions by an estimated 3.46 tons per year per diaphragm pump and 0.38 tons per year per piston pump and VOC emissions by 0.1 tons per year per diaphragm pump and 0.01 tons per year for a piston pump.

6.2.3.3 Cost Impacts

As stated earlier, instrument air conversions require a compressor with a capacity based on the number of control loops at the location. The compressor size is equivalent to the volume of natural gas used by the control loops after adjusting for gas losses during drying, plus any utility air necessary at the facility. This volume can either be calculated via a meter or utilizing a rule of thumb of one cubic foot per minute (cfm) of instrument air per control loop.⁸⁹

For natural gas processing, the cost of emission reductions of the three representative instrument air system sizes was evaluated based on the emissions mitigated from the number of control loops the system can provide and not on a per device basis. This approach was chosen because the EPA assumes new processing plants will need to provide instrumentation for multiple control loops and size the instrument air system accordingly. As was discussed in the 2011 NSPS TSD, the EPA assumes that existing processing plants have an instrument air system in place, including backup systems, and that the cost of adding additional air load to the system would be confined to the incremental cost of upgrading or replacing the compressor and connecting the natural gas-driven pumps to the system. Therefore, for this analysis, the cost being attributed to the replacement of natural gas-driven pumps with air-driven pumps includes the annualized cost of replacing or adding a compressor and installation of the associated piping to connect the pumps to the existing system, and the associated energy costs for operating the new

⁸⁸ U.S. Environmental Protection Agency. Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air. Office of Air and Radiation: Natural Gas Star. Washington, DC. February 2004.

⁸⁹ Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 13: Chemical Injection Pumps. Prepared for the Gas Research Institute and Environmental Protection Agency. EPA-600/R-96-080b. June 1996.

compressor. The size of the compressor required would depend on the additional air load required for the instrument air system to handle the pneumatic pumps.

Because the EPA has no data to characterize the number and types of gas-driven pumps at natural gas processing plants, the EPA developed several model plant scenarios that would likely cover a reasonable range of the numbers and types of pumps that might be found at natural gas processing plants. The model plants represented processing plants with 4, 10, 20, 50 and 100 total pumps. Because there is a significant variation in emission profiles between natural gas-driven diaphragm and piston pumps, the EPA also evaluated, within each model plant, three distribution scenarios for the pumps (i.e., 50 percent diaphragm and 50 percent piston, 25 percent diaphragm and 75 percent piston, and 75 percent diaphragm and 25 percent piston.). In our analysis, the EPA determined the total additional air capacity needed based on the estimated natural gas emission rate for the two types of natural gas-driven pumps, and based on the model plant scenarios, determined the volume of additional air capacity that would need to be addressed by the compressor. The EPA then based the analysis on the use of 90 percent of available capacity of the system. The EPA determined that there were basically three sizes (small, medium and large) compressors that would address the range of model plants. Table 6-4 summarizes the model plant analysis of required system capacity and potential emission reductions. The compressor costs used in our analysis were drawn from the costing analysis conducted for the 2011 NSPS proposal for instrument air systems for pneumatic controllers (See Section 5 of the 2011 TSD). The EPA estimated costs, including operating costs, at three size levels; small, medium and large. Table 6-5 summarizes the cost replacement of the various size compressors into an existing instrument air system.

Because gas emissions are avoided, the use of an instrument air system to control natural gas-driven pumps will have natural gas savings realized from the gas not released. The EPA estimates that each diaphragm pump replaced will save 197 Mcf per year of natural gas from being emitted and each piston pump will save of 22 Mcf per year. The value of the natural gas saved based on \$4.00 per Mcf would be \$786 per year per diaphragm pumps and \$87 per year per piston pump.

6.2.3.4 Secondary Impacts

The secondary impacts from instrument air systems are indirect, variable and dependent on the electrical supply used to power the compressor. No other secondary impacts are expected.

Table 6-4. Model Plant Characterization for Replacing Gas-Driven Pumps with Instrument Air System

Model Plant Size	Annual Compressor Cost ^a	Pump Distribution Scenario ^b	Total Number of Pumps	Number of Diaphragm Pumps	Number of Piston Pumps	Total Additional Air Capacity Required (scf/hour)	Gas Saved ^c (Mcf)	Emission reductions ^d (tpy)	
								Methane	VOC
Small	10,051	50/50	4	2	2	50	49.8	7.7	2.1
		75/25	4	3	1	70	69.8	10.8	3.0
		25/75	4	1	3	30	29.9	4.6	1.3
Medium Small	10,051	50/50	10	5	5	125	124.6	19.2	5.3
		75/25	10	7.5	2.5	175	174.5	26.9	7.5
		25/75	10	2.5	7.5	75	74.7	11.5	3.2
Medium	32,271	50/50	20	10	10	249	249.2	38.4	10.7
		75/25	20	15	5	349	349.1	53.8	15.0
		25/75	20	5	15	149	149.4	23.0	6.4
Medium Large	72,394	50/50	50	25	25	623	623.1	96.0	26.7
		75/25	50	37.5	12.5	873	872.7	134.5	37.4
		25/75	50	12.5	37.5	374	373.5	57.5	16.0
Large	72,394	50/50	100	50	50	1,246	1246.2	192.0	53.4
		75/25	100	75	25	1,745	1745.4	269.0	74.8
		25/75	100	25	75	747	747.0	115.0	32.0

a. See Table 6-5 for the compressor cost analysis.

b. Allocation of type of pumps (i.e., 50/50 is half the pumps are diaphragm and half are piston, 75/25 is 75% of the pumps are diaphragm and 25% are piston, etc.).

c. Based on raw gas emissions of 22.45 scf/hr for a diaphragm pump and 2.48 scf/hr for a piston pump, resulting in \$786 savings per diaphragm pump and \$87 savings per piston pump.

d. Based on 3.36 tons per year of methane and 0.96 tons per year of VOC per diaphragm pump and 0.36 tons per year of methane and 0.11 tons per year of VOC per piston pump.

Table 6-5. Cost of Compressor Replacement for Existing Instrument Air System

Compressor Size	Air Capacity (scf/hour)	Capital Cost (\$)	Capital Cost + Installation^a (2008)	Total Capital Cost^b (\$2012)	Annualized Cost^c (\$)	Labor Cost (\$2008)	Power Cost (\$2008)	Total O&M^d (\$2008)	Total O&M^d (\$2012)	Annual Cost^e (\$)
Small	135	\$3,772	\$5,658	\$5,999	\$854	\$1,334	\$7,340	\$8,674	\$9,197	\$10,051
Medium	562	\$18,855	\$28,282	\$29,989	\$4,270	\$4,333	\$22,075	\$26,408	\$28,002	\$32,271
Large	1,350	\$33,183	\$49,775	\$52,779	\$7,515	\$5,999	\$55,188	\$61,187	\$64,880	\$72,394

a. Installation cost is estimated to be 50 percent of capital cost.

b. Cost was escalated to 2012 using the FRED GDP: Implicit Price Deflator from Jan 2008 to Jan 2012 (<http://research.stlouisfed.org/fred2/series/GDPDEF/#>).

c. Annualized capital cost using a 7% interest rate and an equipment life of 10 years.

d. The total O&M includes both the annual labor cost and the annual power cost.

e. The total annual cost includes the annualized capital cost and the total O&M.

6.2.4 *Install or Route Gas to Combustion Device*

6.2.4.1 *Emission Reduction Potential*

Routing emissions from a natural gas-driven pump to an existing combustion device, or a newly installed combustion device does not reduce the volume of natural gas emitted, but rather combusts the gas volume. Costs for routing the natural gas to a combustion device are further described in Table 6-3. The EPA estimates capture and combustion device efficiency to be 95 percent reduction. Therefore, methane reductions are estimated to be 3.29 tons per year for a diaphragm pump and 0.36 tons per year for a piston pump. Based on the gas composition for natural gas in the production segment, the EPA estimates that routing emissions to a combustion device will reduce VOC emissions by 0.91 tons per year per diaphragm pump and 0.1 tons per year for a piston pump.

6.2.4.2 *Effectiveness*

Capture systems combined with combustion devices are considered a reliable mechanism to reduce approximately 95 percent of emissions. Each combustion device requires a reliable ignition source where the average gas consumption per pilot burner is 70 scf per hour.⁹⁰ Most processing plants or large dehydration facilities already have at least one existing combustion device.

6.2.4.3 *Cost Impacts*

Routing natural gas to an existing combustion device or installing a new combustion device have associated capital costs and operating costs. Based on the analysis conducted for the 2012 NSPS for a combustion device to control emissions from storage vessels,⁹¹ the capital cost for installing a new combustion device is \$32,301 in 2008 dollars. The EPA estimates that the capital cost for installing a new combustion device is \$34,250 and the annual operating costs are \$17,001 in 2012 dollars. Based on the life expectancy for a combustion device, the EPA estimate the annualized cost of installing a new combustion device to be \$21,877 using a 7 percent discount rate. For the proposal, the estimated annualized cost of routing emissions to an existing combustion device was \$285 using a 7 percent discount rate. Because the gas captured is combusted there is no gas savings associated with use of a combustion device.

Based on comments received from the proposal, the EPA revised our estimated cost for routing emissions to an existing control device. EPA received cost estimates from two commenters that claimed

⁹⁰ Ibid.

⁹¹ U.S. EPA docket ID: EPA-HQ-OAR-2010-0505-0045.

that the proposed cost estimate for routing emissions to an existing control device or process was too low. One commenter⁹² claimed that there were engineering costs in addition to the cost to pipe emissions in a closed vent system (CVS) to a control device and that the total capital cost would be \$5,800. Another commenter⁹³ provided detailed cost with respect to installing a CVS that considers that there could be a significant distance between the pump location and the control device on a site. This commenter suggested that the cost would be \$8,500 to route emissions through a CVS to an existing control device.

The cost estimates the EPA received from the commenters were not directly comparable to each other, nor were they directly comparable to the proposal cost estimate. Therefore, in order to consider the additional costs provided by the commenters in our analysis, the EPA treated the costs as individual, all-inclusive cost estimates for routing emissions to an existing control device. The EPA calculated the average of the capital cost from proposal and the two commenter estimates and found the estimated capital cost to be \$5,433. Using the 7 percent discount rate, the EPA calculated the annualized cost for each of the commenter estimates to be \$826 (from the \$5,800 estimate) and \$1,210 (from the \$8,500 estimate). The EPA averaged these annualized costs with the proposed annualized cost of \$285 which resulted in a revised annualized cost of \$774.

6.2.4.4 Secondary Impacts

There are secondary impacts from combustion of emissions routed from natural gas-driven pumps. The combustion of the recovered natural gas creates secondary emissions of hydrocarbons, NO_x, CO₂, and CO. A summary of the estimated secondary emission are presented in Table 6-6. No other wastes should be created or wastewater generated.

⁹² EPA-HQ-OAR-2010-0505-6884-A1.

⁹³ EPA-HQ-OAR-2010-0505-6881.

Table 6-6. Secondary Impacts from Pneumatic Pumps Routed to a Combustion Device

Pump Type	Secondary Impacts (tpy)				
	THC ^a	CO ^b	CO ₂ ^c	NO _x ^d	PM ^e
Diaphragm	0.02	0.03	14	0.01	0
Piston	0.002	0.004	2	0.001	0

a. Based on combustion of natural gas stream and AP-42 Total Hydrocarbons emission factors for industrial flares.

b. Based on combustion of natural gas stream and AP-42 Carbon Monoxide emission factors for industrial flares.

c. Based on combustion of natural gas stream and 40 CFR Part 98, subpart Y, Equation Y-2.

d. Based on combustion of natural gas stream and AP-42 Nitrogen Oxides emission factors for industrial flares.

e. Based on combustion of natural gas stream and AP-42 Particulate Matter emission factors for industrial flares. Assumes a “lightly smoking” flare.

6.2.5 Install or Route Gas to VRU

6.2.5.1 Emission Reduction Potential

Use of a vapor recovery technology has the potential to reduce the emissions from natural gas-drive pumps by 100 percent if all vapor is recovered. However, the effectiveness of the gas capture system and downtime for maintenance would reduce capture efficiency and therefore, the EPA estimates that routing emissions from a natural gas-driven pump to an existing VRU, or a newly installed VRU can reduce the gas emitted by approximately 95 percent, while at the same time, capturing the gas for beneficial use. The EPA estimates that methane emission reductions for routing gas to a VRU to be 3.29 tons per year for a diaphragm pump and 0.36 tons per year for a piston pump. Based on the gas composition for natural gas in the production segment, the EPA estimates that routing emissions to a VRU will reduce VOC emissions by 0.91 tons per year per diaphragm pump and 0.1 tons per year for a piston pump.

6.2.5.2 Effectiveness

VRUs are reliable, typically with a backup compressor system to allow for shutdowns and repairs. VRUs are more economical for facilities with multiple gas emission sources that can be routed to the VRU. Some of these other emission sources can include tanks, dehydrators, and compressors and as a result, VRUs are more common at natural gas processing plants and large dehydration facilities.

6.2.5.3 Cost Impacts

Routing natural gas to an existing VRU or installing a new VRU, have both capital costs and maintenance costs. Based on the analysis conducted for the 2012 NSPS for control of emissions from

storage vessels⁹⁴, the capital cost and installation costs for a VRU is estimated to be \$98,186 in 2008 dollars. The EPA estimates the capital cost of installation of a VRU to be \$104,111 and the annual operation and maintenance cost to be \$9,932 in 2012 dollars. If a VRU is already on site, then the additional costs for routing emissions from a pump are small, as the majority of costs are piping. The total annualized cost of a new VRU is estimated to be \$24,755 based on a 7 percent discount rate.

As discussed above, for the proposal the EPA estimated the cost of routing emissions to an existing VRU to be \$2,000 in 2012 dollars. The annualized cost of routing gas to an existing VRU is estimated to be \$285 based on a 7 percent discount rate. In addition, because there is potential for beneficial use of gas recovered through the VRU, the EPA estimates an annual gas recovered as 187 Mcf per year per diaphragm pump and 21 Mcf per year per piston pump. The gas savings realized is estimated to be \$749 per diaphragm pump and \$84 per piston pump, per year based on \$4.00 value per Mcf of gas recovered.

As discussed above in section 6.2.4.3 with respect to routing emissions to an existing combustion control device, the EPA considered additional cost estimates submitted during the proposed rule public comment period and have revised the estimated cost for routing emissions to an existing VRU to be the same as the cost of routing to an existing combustion device, or \$774 annualized cost.

6.2.5.4 Secondary Impacts

The secondary impacts from use of a VRU are indirect, variable and dependent on the electrical supply used to power the VRU. No other secondary impacts are expected.

6.3 Regulatory Options

The control technologies evaluated for natural gas-driven pumps included options that provided 100 percent emission reductions. These options included replacing the pumps with solar-powered pumps or electric pumps or use of instrument air systems to eliminate natural gas emissions. The EPA also evaluated gas recovery and gas combustion technologies that would result in 95 percent emission reductions.

The use of instrument air systems and electric pumps requires a consistent supply of electric power and the use of solar-powered pumps and routing emissions to a VRU requires a reliable supply of backup electric power. Because reliable electric power is not universally available for production, gathering and boosting and transmission and storage locations these control technologies were

⁹⁴ Ibid.

determined to not be technically viable options for those segments. Because electric power is typically available at natural gas processing plants, those technologies are considered technically viable for the processing segment.

For the final rule, we have revaluated our best available emissions and usage data for piston pumps. Based on our emissions data these pumps have inherently low emissions primarily due to size. In addition, available information indicates that these pumps are typically used intermittently which further limits their emission potential. Therefore, we determined that based on their low emissions, control of piston pumps is not warranted at this time and we have excluded piston pumps from further evaluation.

Based on the costs and estimated emission reductions for each of the viable emission control alternatives, the EPA further evaluated the cost per ton of emissions reduced for methane and VOC. The cost per ton of emissions reduced was calculated in two ways. The first method, or single-pollutant approach, allocated all of the costs to one pollutant and zero cost to the other. The second method, or the multipollutant approach, allocated costs among the pollutants that a given technology reduced (i.e., methane and VOC). This multipollutant approach is based on estimates of the percentage reduction expected for each pollutant.

Based on the above considerations, for the proposal the EPA evaluated the following regulatory alternatives:

- Regulatory Option 1. Require a zero emission standard for diaphragm pumps at natural gas processing plants.
- Regulatory Option 2. Require a 95 percent emissions reduction standard for diaphragm pumps production facilities.
- Regulatory Option 3. Require a 95 percent emissions reduction standard for diaphragm pumps production facilities only where an existing control device or process is available.

6.3.1 Evaluation of Regulatory Options

Regulatory Option 1 would require zero emissions of methane and VOC from gas-driven, diaphragm pumps at natural gas processing plants. To attain this emission reduction, the facility would need to either replace the natural gas-driven diaphragm pumps with solar-powered or electric pumps or use instrument air systems to replace natural gas-driven function with air-driven function. The EPA evaluated the cost of control for each of these options based on the estimated emission reductions as detailed above.

Using the single-pollutant (allocate all of the costs to one pollutant and zero to the other) for calculating cost of control, for the use of an instrument air system at natural gas processing plants the EPA estimates the cost per ton of methane reduced to be between \$374 and \$2,185 and the cost per ton of VOC reduced to be between \$1,344 and \$7,861 without considering gas savings. With gas savings, for the use of an instrument air system at natural gas processing plants, the cost per ton of methane reduced was \$146 and \$1,957, and the cost per ton of VOC reduced was between \$527 and \$7,042. Using the multi-pollutant method of allocating cost between methane and VOC, the EPA estimates the cost of control, without considering gas savings, ranged from \$187 to 1,093 per ton of methane reduced and \$672 and \$3,930 per ton of VOC reduced. When considering gas savings, the EPA found the cost of control to range from \$73 to \$979 per ton of methane reduced and \$263 to \$3,521 per ton of VOC reduced. The range of cost per ton is dependent on the size of the system/compressor needed for the facility.

Under the single pollutant approach, the EPA estimates the cost of control for installation of either an electric pump or solar-powered pumps to be between (\$136) and \$1,223 per ton of methane reduced or between (\$489) and \$4,235 per ton of VOC reduced, considering gas savings.⁹⁵ Under the multi-pollutant approach and considering savings, the EPA estimates the cost of control for installation of either an electric pump or solar-powered pump to be between (\$68) and \$1,337 per ton of methane reduced and between (\$244) and \$2,112 per ton of VOC reduced, considering gas savings. The EPA considers these costs to be reasonable. Based on these cost of control values for methane and VOC, EPA determined that Regulatory Option 1 is appropriate for the natural gas processing segment. Tables 6-7 through 6-10 summarize the cost of control for each of these options for the natural gas processing segment. For the final rule, the EPA had no changes to this analysis for natural gas processing plants.

The control technologies that produce zero emissions (or 100 percent reduction in emissions) (i.e., solar-powered and electric pumps and instrument air systems) are not technically viable alternatives for the production and transmission and storage segments where reliable electric power is not universally available. Instead, the available control technologies for those segments produce a 95 percent emission reduction. Therefore, the second regulatory option would require a 95 percent reduction in emissions at production sites, transmission stations and storage facilities. To attain this emission reduction, the facility could route emissions to a VRU or a combustion device.

⁹⁵ Negative cost reflects a net savings considering gas saved.

For the proposal, the EPA calculated the cost of control for this option for each control technology by the single-pollutant and multi-pollutant methods described above. For the installation of a new VRU or combustion device, the cost of control for methane and VOC emission reductions ranged from \$3,652 to over \$1 million per ton. The cost of control for a new combustion device ranged between \$3,328 to over \$1 million per ton. Based on these cost of control values for methane and VOC, Regulatory Option 2 was rejected for all segments. For the final rule, the EPA had no changes to this analysis. Tables 6-11 through 6-14 summarize the cost of control for Option 2 for all segments.

For the proposal, EPA evaluated Regulatory Option 3 to require 95 percent control of emissions in all segments only where an existing control device or process was available. The sole cost associated with this option that would be attributed to the emission reduction would be the cost of routing the diaphragm pump emissions to the control device. As discussed above, for the final rule, the EPA has revised the estimated cost to route emissions to either an existing VRU or an existing combustion device based on commenter provided cost estimates. Under the new analysis the capital cost is approximately \$5,433, which when annualized at a 7 percent discount rate, resulted in an annualized cost of \$774. Based on this annualized cost, using the single-pollutant approach of calculating cost of control, the cost of control for methane emission reductions with an existing VRU or an existing combustion device is \$235 per ton for all segments. The cost of control for VOC reductions is \$847 per ton for the production and processing segments and \$8,496 per ton for the transmission and storage segment. Considering natural gas savings when an existing VRU is used, the cost of control for methane emission reductions is \$8 per ton for all segments. The cost of control for VOC emission reductions is \$27 per ton for the production and processing segments and \$274 per ton for the transmission and storage segment.

Using the multi-pollutant approach of calculating cost of control, the cost of control for methane emission reductions with an existing VRU or an existing combustion device is \$118 per ton for all segments. The cost of control for VOC reductions is \$423 per ton for the production and processing segments and \$4,248 per ton for the transmission and storage segment. Considering natural gas savings when an existing VRU is used, the cost of control for methane emission reductions is \$4 per ton for all segments. The cost of control for VOC emission reductions is \$14 per ton for the production and processing segments and \$137 per ton for the transmission and storage segment... EPA found these methane costs to be reasonable and selected Option 3 for control of natural gas-driven diaphragm pump emissions for all segments. Tables 6-15 through 6-16 summarize results of our cost of control analyses.

Table 6-7. Cost of Control for Use of Instrument Air Systems at Natural Gas Processing Plants - Single-Pollutant⁹⁶

Plant Size	Compressor Cost ^a	Scenario ^b	Total Number of Pumps	Total Gas Saved ^c (Mcf)	Emission reductions ^d (tpy)		Cost of control (without savings) (\$/ton)		Cost of control (with savings) ^c (\$/ton)	
					Methane	VOC	Methane	VOC	Methane	VOC
Small	\$10,051	50/50	4	49.8	7.7	2.1	\$1,309	\$4,708	\$1,081	\$3,890
		75/25	4	69.8	10.8	3.0	\$934	\$3,360	\$707	\$2,543
		25/75	4	29.9	4.6	1.3	\$2,185	\$7,861	\$1,957	\$7,042
Medium Small	\$10,051	50/50	10	124.6	19.2	5.3	\$523	\$1,883	\$296	\$1,065
		75/25	10	174.5	26.9	7.5	\$374	\$1,344	\$146	\$527
		25/75	10	74.7	11.5	3.2	\$874	\$3,144	\$646	\$2,325
Medium	\$32,271	50/50	20	249.2	38.4	10.7	\$840	\$3,023	\$613	\$2,205
		75/25	20	349.1	53.8	15.0	\$600	\$2,158	\$373	\$1,340
		25/75	20	149.4	23.0	6.4	\$1,403	\$5,048	\$1,175	\$4,229
Medium Large	\$72,394	50/50	50	623.1	96.0	26.7	\$837	\$3,011	\$527	\$1,895
		75/25	50	872.7	134.5	37.4	\$558	\$2,007	\$311	\$1,119
		25/75	50	373.5	57.5	16.0	\$1,674	\$6,022	\$1,031	\$3,711
Large	\$72,394	50/50	100	1246.2	192.0	53.4	\$418	\$1,505	\$150	\$539
		75/25	100	1745.4	269.0	74.8	NA - Beyond Capacity			
		25/75	100	747.0	115.0	32.0	\$837	\$3,011	\$402	\$1,446

a. See Table 6-5 for compressor cost analysis.

b. Allocation of type of pumps (i.e., 50/50 is half the pumps are diaphragm and half are piston, 75/25 is 75% of the pumps are diaphragm and 25% are piston, etc.).

c. Based on raw gas emissions of 22.45 scf/hr for a diaphragm pump and 2.48 scf/hr for a piston pump, resulting in \$786 savings per diaphragm pump and \$87 savings per piston pump.

d. Based on 3.36 tons per year of methane and 0.96 tons per year of VOC per diaphragm pump and 0.36 tons per year of methane and 0.11 tons per year of VOC per piston pump.

⁹⁶ As explained earlier, this control option simultaneously reduces both methane (which is being evaluated for controlling the pollutant GHG) and VOC. Under the single pollutant approach, all costs are attributed to one pollutant and zero to the other. For simplicity, the table presents the cost per ton of the assigned pollutant; the table does not present the cost per ton of the one that is assigned zero cost because it is always zero.

Table 6-8. Cost of Control for Use of Instrument Air Systems at Natural Gas Processing Plants - Multi-Pollutant Method

Plant Size	Compressor Cost ^a	Scenario ^b	Total Number of Pumps	Total Gas Saved ^c (Mcf)	Emission reductions ^d (tpy)		Cost of Control (without savings) (\$/ton)		Cost of Control (with savings) ^c (\$/ton)	
					Methane	VOC	Methane	VOC	Methane	VOC
Small	\$10,051	50/50	4	49.8	7.7	2.1	\$654	\$2,354	\$541	\$1,945
		75/25	4	69.8	10.8	3.0	\$467	\$1,680	\$353	\$1,271
		25/75	4	29.9	4.6	1.3	\$1,093	\$3,930	\$979	\$3,521
Medium Small	\$10,051	50/50	10	124.6	19.2	5.3	\$262	\$942	\$148	\$533
		75/25	10	174.5	26.9	7.5	\$187	\$672	\$73	\$263
		25/75	10	74.7	11.5	3.2	\$437	\$1,572	\$323	\$1,163
Medium	\$32,271	50/50	20	249.2	38.4	10.7	\$420	\$1,512	\$307	\$1,103
		75/25	20	349.1	53.8	15.0	\$300	\$1,079	\$186	\$670
		25/75	20	149.4	23.0	6.4	\$702	\$2,524	\$588	\$2,114
Medium Large	\$72,394	50/50	50	623.1	96.0	26.7	\$418	\$1,505	\$263	\$948
		75/25	50	872.7	134.5	37.4	\$279	\$1,004	\$156	\$559
		25/75	50	373.5	57.5	16.0	\$837	\$3,011	\$516	\$1,855
Large	\$72,394	50/50	100	1246.2	192.0	53.4	\$209	\$753	\$75	\$269
		75/25	100	1745.4	269.0	74.8	NA - Beyond Capacity			
		25/75	100	747.0	115.0	32.0	\$418	\$1,505	\$201	\$723

a. See Table 6-5 for compressor cost analysis.

b. Allocation of type of pumps (i.e., 50/50 is half the pumps are diaphragm and half are piston, 75/25 is 75% of the pumps are diaphragm and 25% are piston, etc.).

c. Based on raw gas emissions of 22.45 scf/hr for a diaphragm pump and 2.48 scf/hr for a piston pump, resulting in \$786 savings per diaphragm pump and \$87 savings per piston pump.

d. Based on 3.36 tons per year of methane and 0.96 tons per year of VOC per diaphragm pump and 0.36 tons per year of methane and 0.11 tons per year of VOC per piston pump.

Table 6-9. Cost of Control for Replacement with Solar-Powered or Electric Pumps at Natural Gas Processing Plants - Single-Pollutant⁹⁷

Type of Pump	Control Option	Emission Factor (tpy/pump)		Annualized Cost (\$)	Natural Gas			Cost of Control (\$/ton)			
		Methane	VOC		Emission Factor (scf/h)	Saved (Mcf/yr)	Value (\$)	without savings		with savings	
								Methane	VOC	Methane	VOC
Diaphragm	Electric ^a	3.46	0.96	4,175	22.45	197	\$786	\$276	\$994	\$49	\$175
Diaphragm	Solar	3.46	0.96	\$2,000	22.45	197	\$786	\$92	\$330	(\$136)	(\$489)

a. For electric pumps, annual cost assumes a 5.0 BHP electric pump as reported in NGS LL "Replacing Gas-Assisted Glycol Pumps with Electric Pumps". Assumes installation is 10% of the capital cost.

Table 6-10. Cost of Control for Replacement with Solar-Powered or Electric Pumps at Natural Gas Processing Plants - Multi-Pollutant Method

Type of Pump	Control Option	Emission Factor (tpy/pump)		Annualized Cost (\$)	Natural Gas			Cost of Control (\$/ton)			
					Emission Factor (scf/h)	Saved (Mcf/yr)	Value (\$)	without savings		with savings	
		Methane	VOC					Methane	VOC	Methane	VOC
Diaphragm	Electric ^a	3.46	0.96	\$4,175	22.45	197	\$786	\$138	\$497	\$24	\$88
Diaphragm	Solar	3.46	0.96	\$2,000	22.45	197	\$786	\$46	\$165	(\$68)	(\$244)

a. For electric pumps, annual cost assumes a 5.0 BHP electric pump as reported in NGS LL "Replacing Gas-Assisted Glycol Pumps with Electric Pumps". Assumes installation is 10% of the capital cost.

⁹⁷ See footnote 50.

Table 6-11. Cost of Control for Routing Gas-Driven Diaphragm Pump Emissions to a New VRU - Single-Pollutant Method

Pump Type/ Segment	Emission Reductions (tpy/pump)		Annualized Cost (\$)	Natural Gas			Cost of Control (\$/ton)			
	Methane	VOC		Emission Factor (scf/h)	Saved (Mcf/yr)	Value (\$)	without savings		with savings	
							Methane	VOC	Methane	VOC
Diaphragm Pumps										
Production	3.29	0.91	\$24,755	22.45	187	\$749	\$7,531	\$27,094	\$7,304	\$26,275
Processing	3.29	0.91	\$24,755	22.45	187	\$749	\$7,531	\$27,094	\$7,304	\$26,275
Transmission	3.29	0.09	\$24,755	22.45	187	\$749	\$7,531	\$271,888	\$7,304	\$263,666
Storage	3.29	0.09	\$24,755	22.45	187	\$749	\$7,531	\$271,888	\$7,304	\$263,666

Note: No gas savings is attributed to transmission and storage.

Table 6-12. Cost of Control for Routing Gas-Driven Diaphragm Pump Emissions to a New VRU - Multi-Pollutant Method

Segment	Emission Reductions (tpy/pump)		Annualized Cost (\$)	Natural Gas			Cost of Control (\$/ton)			
	Methane	VOC		Emission Factor (scf/h)	Saved (Mcf/yr)	Value (\$)	without savings		with savings	
							Methane	VOC	Methane	VOC
Diaphragm Pumps										
Production	3.29	0.91	\$24,755	22.45	187	\$749	\$3,766	\$13,547	\$3,652	\$13,137
Processing	3.29	0.91	\$24,755	22.45	187	\$749	\$3,766	\$13,547	\$3,652	\$13,137
Transmission	3.29	0.09	\$24,755	22.45	187	\$749	\$3,766	\$135,944	\$3,652	\$131,833
Storage	3.29	0.09	\$24,755	22.45	187	\$749	\$3,766	\$135,944	\$3,652	\$131,833

Note: No gas savings is attributed to transmission and storage.

Table 6-13. Estimated Cost of Control for Emission Reductions from Routing Gas-Drive Diaphragm Pump Emissions to a New Combustion Device - Single-Pollutant Method

Segment	Type of Pump	Emission reductions (tons/yr-pump)		Annualized Cost (\$2012)	Cost of Control (\$/ton)	
		Methane	VOC		Methane	VOC
Production	Diaphragm	3.287	0.914	\$21,877	\$6,656	\$23,944
Processing	Diaphragm	3.287	0.914	\$21,877	\$6,656	\$23,944
Transmission	Diaphragm	3.287	0.091	\$21,877	\$6,656	\$240,279
Storage	Diaphragm	3.287	0.091	\$21,877	\$6,656	\$240,279

Table 6-14. Estimated Cost of Control for Emission Reductions from Routing Gas-Drive Diaphragm Pump Emissions to a New Combustion Device - Multi-Pollutant Method

Segment	Type of Pump	Individual Pneumatic Pump Emission Reductions (tons/yr-pump)		Annualized Cost (\$2012)	Cost of Control (\$/ton)	
		Methane	VOC		Methane	VOC
Production	Diaphragm	3.287	0.914	\$21,877	\$3,328	\$11,972
Processing	Diaphragm	3.287	0.914	\$21,877	\$3,328	\$11,972
Transmission	Diaphragm	3.287	0.091	\$21,877	\$3,328	\$120,140
Storage	Diaphragm	3.287	0.091	\$21,877	\$3,328	\$120,140

Table 6-15. Cost of Control for Routing Gas-Driven Diaphragm Pump Emissions to an Existing Combustion Device or VRU - Single-Pollutant Method

Pump Type/ Segment	Emission Reductions ^a (tpy/pump)		Annualized Cost ^b (\$)	Natural Gas			Cost of Control (\$/ton)			
	Methane	VOC		Emission Factor (scf/h)	Saved (Mcf/ yr)	Value ^c (\$)	without savings		with savings ^d	
							Methane	VOC	Methane	VOC
Diaphragm Pumps										
Production	3.29	0.91	\$774	22.45	187	\$749	\$235	\$847	\$8	\$27
Processing	3.29	0.91	\$774	22.45	187	\$749	\$235	\$847	\$8	\$27
Transmission	3.29	0.09	\$774	22.45	187	\$749	\$235	\$8,496	\$8	\$274
Storage	3.29	0.09	\$774	22.45	187	\$749	\$235	\$8,496	\$8	\$274

a. Based on 95 percent control.

b. Based on capital cost of \$5,433 annualized using a 7 percent discount rate.

c. Based on \$4.00 per Mcf average price for natural gas.

d. Applies to VRU only. There is no gas savings with a combustion device.

Table 6-16. Cost of Control for Routing Gas-Driven Diaphragm Pump Emissions to an Existing Combustion Device or VRU - Multi-Pollutant Method

Pump Type/ Segment	Emission Reductions ^a (tpy/pump)		Annualized Cost ^b (\$)	Natural Gas			Cost of Control (\$/ton)			
	Methane	VOC		Emission Factor (scf/h)	Saved (Mcf/yr)	Value ^c (\$)	without savings		with savings ^d	
							Methane	VOC	Methane	VOC
Diaphragm Pumps										
Production	3.29	0.91	\$774	22.45	187	\$749	\$118	\$423	\$4	\$14
Processing	3.29	0.91	\$774	22.45	187	\$749	\$118	\$423	\$4	\$14
Transmission	3.29	0.09	\$774	22.45	187	\$749	\$118	\$4,248	\$4	\$137
Storage	3.29	0.09	\$774	22.45	187	\$749	\$118	\$4,248	\$4	\$137

a. Based on 95 percent control.

b. Based on capital cost of \$5,433 annualized using a 7 percent discount rate.

c. Based on \$4.00 per Mcf average price for natural gas.

d. Applies to VRU only. There is no gas savings with a combustion device.

7.0 COMPRESSORS

Compressors are mechanical devices that increase the pressure of natural gas and allow the natural gas to be transported from the production site, through the supply chain, and to the consumer. The types of compressors that are used by the oil and natural gas industry as prime movers are reciprocating and centrifugal compressors.

The 2012 NSPS promulgated requirements for control of emissions from wet seal centrifugal compressors and reciprocating compressors in the production and processing segments. During development of the 2012 NSPS amendments, methane and VOC emissions for these sources were estimated and included in the cost and impact analysis. See the 2011 NSPS TSD for information on the production and processing segments.

This chapter discusses the emissions from these compressors in the transmission and storage segment and provides emission estimates for reducing emission from these types of compressors. In addition, nationwide emissions estimates from new sources are estimated. Options for controlling emissions from these compressors are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for both reciprocating and centrifugal compressors.

7.1 Process Description

7.1.1 *Reciprocating Compressors*

In a reciprocating compressor, natural gas enters the suction manifold, and then flows into a compression cylinder where it is compressed by a piston driven in a reciprocating motion by the crankshaft powered by an internal combustion engine. Emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. The compressor rod packing system consists of a series of flexible rings that create a seal around the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. However, over time, during operation of the compressor, the rings become worn and the packing system will need to be replaced to prevent excessive leaking from the compression cylinder.

7.1.2 *Centrifugal Compressors*

Centrifugal compressors use a rotating disk or impeller to increase the velocity of the gas where it is directed to a divergent duct section that converts the velocity energy to pressure energy.

These compressors are primarily used for continuous, stationary transport of natural gas in the processing and transmission systems. Many centrifugal compressors use wet (meaning oil) seals around the rotating shaft to prevent natural gas from escaping where the compressor shaft exits the compressor casing. The wet seals use oil which is circulated at high pressure to form a barrier against compressed natural gas leakage. The circulated oil entrains and absorbs some compressed natural gas which is released to the atmosphere during the seal oil recirculation process. Alternatively, dry seals can be used in place of wet seals in centrifugal compressors. Dry seals prevent leakage by using the opposing force created by hydrodynamic grooves and springs. The opposing forces create a thin gap of high pressure gas between the rings through which little gas can leak. The rings do not wear or need lubrication because they are not in contact with each other. Therefore, operation and maintenance costs are typically lower for dry seals in comparison to wet seals.

7.2 Emissions Data and Emissions Factors

7.2.1 Summary of Major Studies and Emissions Factors

There are a few studies that have been conducted that provide emission estimates from reciprocating and centrifugal compressors. These studies are provided in Table 7-1, along with the type of information contained in the study.

Table 7-1. Major Studies Reviewed for Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Information	Emissions Information	Control Information
Public review draft Inventory of U.S. GHG Emissions and Sinks: 1990-2014 ^a	EPA	2016	Nationwide	X	
GHG Mandatory Reporting Rule and TSD ^b	EPA	2013	Nationwide	X	
Methane Emissions from the Natural Gas Industry ^c	GRI/EPA	1996	Nationwide	X	
Natural Gas STAR Program ^{d,e}	EPA	1993-2010	Nationwide	X	X
Natural Gas Industry Methane Emission Factor Improvement Study ^f	URS Corporation, UT Austin, and U.S. EPA	2011	None	Emission Factors Only	
Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production: Summary and	API/ANGA	2012	Regional	X ^h	

Report Name	Affiliation	Year of Report	Activity Information	Emissions Information	Control Information
Analysis of API and ANGA Survey Responses ^{g, h}					
Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries ⁱ	ICF International (Prepared for the Environmental Defense Fund)	2014	Regional	X	X

a. U.S. EPA. Public review draft of Inventory of U.S. Greenhouse Gas Emission and Sinks 1990-2014. Washington, DC.

b. U.S. EPA. GHG Emissions Reporting From the Petroleum and Natural Gas Industry: Background TSD. Climate Change Division. Washington, DC. November 2014.

c. National Risk Management Research Laboratory. GRI/EPA Research and Development, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks. Prepared for the U.S. Department of Energy, EIA. EPA-600/R-96-080h. June 1996.

d. U.S. EPA. Lessons Learned: Reducing Methane Emissions from Compressor Rod Packing Systems. Natural Gas STAR. EPA. 2006.

e. U.S. EPA. Lessons Learned: Replacing Wet Seals with Dry Seals In Centrifugal Compressors. *Natural Gas STAR*. EPA. 2006.

f. URS Corporation/University of Texas at Austin. 2011. Natural Gas Industry Methane Emission Factor Improvement Study, Final Report. December 2011.

http://www.utexas.edu/research/ceer/GHG/files/FReports/XA_83376101_Final_Report.pdf.

g. API and America's Natural Gas Alliance (ANGA). 2012. Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production. Summary and Analysis of API and ANGA Survey Responses. Final Report. September 21, 2012.

h. The API/ANGA study provided information on equipment counts that could augment nationwide emissions calculations. No source emissions information was included.

i. ICF International. 2014. Economic Analysis of Methane Emissions Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries. Prepared for the Environmental Defense Fund. March 2014.

7.2.2 Representative Reciprocating and Centrifugal Compressor Emissions

The methodology for estimating emission from reciprocating compressor rod packing was to use the methane emission factors referenced in the EPA/GRI study⁹⁸ and the methane-to-VOC ratio developed in the gas composition memorandum.⁹⁹ The emission factors in the EPA/GRI document were expressed in thousand standard cubic feet per cylinder (Mscf/cyl), and were multiplied by the average number of cylinder per reciprocating compressor at each oil and gas industry segment. The volumetric methane emission rate was converted to a mass emission rate using a density of 41.63 lbs of methane per Mcf. This conversion factor was developed assuming that methane is an ideal gas and using the ideal gas law to calculate the density. A summary of the methane emission factors is presented in Table 7-2. Once the methane emissions were calculated, the ratio of VOC-to-methane

⁹⁸ National Risk Management Research Laboratory. GRI/EPA Research and Development, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks. Prepared for the U.S. Department of Energy, Energy Information Administration. EPA-600/R-96-080h. June 1996.

⁹⁹ See footnote 3.

was used to estimate VOC emissions. The specific VOC-to-methane ratios used for this analysis were 0.278 lbs VOC per pound of methane for the production and processing segments, and 0.0277 lbs VOC per pound of methane for the transmission and storage segment. A summary of the reciprocating compressor emissions are presented in Table 7-3.

The centrifugal compressor emission factors for wet seals and dry seals are based on data used in the GHG Inventory¹⁰⁰. The wet seals methane emission factor was calculated based on a sampling of 48 wet seal centrifugal compressors. The dry seal methane emission factor was based on data collected by the Natural Gas STAR Program. The methane emissions were converted to VOC and HAP emissions using the same gas composition ratios that were used for reciprocating engines.¹⁰¹

Since publication of the white paper, additional data have become available on compressor emissions in transmission and storage, including reporting year 2014 data from GHGRP, and new measurement data from Subramanian et al. 2015. These data confirm the significant emissions from these sources, but indicate that emissions levels differ from those assumed in this analysis. In the 2013 GHGRP transmission and storage data set, reported emissions from reciprocating compressors are 2,100,647 tons CO₂ Eq. of methane, and reported emissions from centrifugal compressors are 697,643 tons CO₂ Eq. of methane. The Subramanian study, compared total average methane emissions per compressor in transmission and storage for both reciprocating and centrifugal compressors to those in the 2015 GHG Inventory, and found that the 2015 GHG Inventory had higher average emissions. The 2016 GHGI inventory includes updated estimates for reciprocating and centrifugal compressors, based on data from the Subramanian study and GHGRP.

¹⁰⁰ U.S. EPA. Methodology for Estimating CH₄ and CO₂ Emissions from Petroleum Systems. GHG Inventory: Emission and Sinks: 1990-2012. Washington, DC. 2014.

¹⁰¹ Ibid.

Table 7-2. Methane Emission Factors for Reciprocating and Centrifugal Compressors

Compressor Station	Reciprocating Compressors			Centrifugal Compressors		
	Methane Emission Factor (scf/hr-cylinder)	Average Number of Cylinders	Pressurized Factor ^a	Wet Seal Methane Emission Factor (scf/minute)	Dry Seals Methane Emission Factor (scf/minute)	Pressurized Factor ^a
Transmission	57 ^b	3.3	79.1%	47.7 ^d	6 ^d	30.0 ^d
Storage	51 ^c	4.5	67.5%	47.7 ^d	6 ^d	22.4 ^d

a. Percent of hours per year that a compressor is pressurized.

b. EPA/GRI. (1996). "Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks." Table 4-17.

c. EPA/GRI. (1996). "Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks." Table 4-24.

d. U.S. EPA. Methodology for Estimating CH₄ and CO₂ Emissions from Petroleum Systems. GHG Inventory: Emission and Sinks: 1990-2012. Washington, DC. 2014. Annex 3.5 Table A-129.

Table 7-3. Baseline Emission Estimates for Reciprocating and Centrifugal Compressors

Compressor Location	Baseline Emission Estimates (tpy)	
	Methane	VOC
Reciprocating Compressors		
Transmission	27.1	0.75
Storage	28.2	0.78
Centrifugal Compressors (Wet Seals)		
Transmission	157	4.34
Storage	117	3.24
Centrifugal Compressors (Dry Seals)		
Transmission	19.7	0.546
Storage	14.7	0.407

7.3 Control Techniques

7.3.1 Potential Control Techniques

The potential control options reviewed for reducing emissions from reciprocating compressors include control techniques that limit the leaking of natural gas across the piston rod packing. This includes replacement of the compressor rod packing or replacement of the piston rod.

The replacement of the rod packing is a maintenance task performed on reciprocating compressors to reduce the leakage of natural gas across the piston rod. Over time the packing rings wear and allow more natural gas to escape around the piston rod. Regular replacement of these rings

reduces methane and VOC emissions. Therefore, this control technique was determined to be an appropriate option for reciprocating compressors.

Like the packing rings, piston rods on reciprocating compressors also deteriorate. Piston rods, however, wear more slowly than packing rings, having a life of about 10 years.¹⁰² Rods wear “out-of-round” or taper when poorly aligned, which affects the fit of packing rings against the shaft (and therefore the tightness of the seal) and the rate of ring wear. An out-of-round shaft not only seals poorly, allowing more leakage, but also causes uneven wear on the seals, thereby shortening the life of the piston rod and the packing seal. Replacing or upgrading the rod can reduce reciprocating compressor rod packing emissions. A summary of these techniques are presented in the following sections.

Potential control options to reduce emissions from centrifugal compressors include control techniques that limit the leaking of natural gas across the rotating shaft, or capture and destruction of the emissions using a combustion device. A summary of these techniques are presented in the following sections.

One control technique for limiting or reducing the emission from the rotating shaft of a centrifugal compressor is a mechanical dry seal system. This control technique uses rings to prevent the escape of natural gas across the rotating shaft. This control technique was determined to be a viable option for reducing emission from centrifugal compressors.

For centrifugal compressors equipped with wet seals, a combustion device was considered to be a viable option for reducing emissions from centrifugal compressors. Centrifugal compressors require seals around the rotating shaft to prevent natural gas from escaping where the shaft exits the compressor casing. “Beam” type compressors have two seals, one on each end of the compressor, while “over-hung” compressors have a seal on only the “inboard” (motor end) side. These seals use oil, which is circulated under high pressure between three rings around the compressor shaft, forming a barrier against the compressed gas leakage. The center ring is attached to the rotating shaft, while the two rings on each side are stationary in the seal housing, pressed against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. The seal also includes “O-

¹⁰² U.S. EPA. Lessons Learned: Reducing Methane Emissions from Compressor Rod Packing Systems. Natural Gas STAR. Washington DC. 2006.

ring” rubber seals, which prevent leakage around the stationary rings. The oil barrier allows some gas to escape from the seal, but considerably more gas is entrained and absorbed in the oil under the high pressures at the “inboard” (compressor side) seal oil/gas interface, thus contaminating the seal oil. Seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated back to the seal. As a control measure, the recovered gas would then be sent to a combustion device.

7.3.2 Reciprocating Compressor Rod Packing Replacement

7.3.2.1 Description

Reciprocating compressor rod packing consists of a series of flexible rings that fit around a shaft to create a seal against leakage. As the rings wear, they allow more compressed gas to escape, increasing rod packing emissions. Rod packing emissions typically occur around the rings from slight movement of the rings in the cups as the rod moves, but can also occur through the “nose gasket” around the packing case, between the packing cups, and between the rings and shaft. If the fit between the rod packing rings and rod is too loose, more compressed gas will escape. Periodically replacing the rod packing ensures the correct fit is maintained between packing rings and the rod.

7.3.2.2 Emissions Reduction Potential

As discussed above, regular replacement of the reciprocating compressor rod packing can reduce the leaking of natural gas across the piston rod. The emission reductions for the transmission and storage segments were calculated by multiplying the number of new reciprocating compressors in each segment by the difference between the average rod packing emission factors (as presented in Table 6-2) and the average emission factor for newly installed rod packing. This calculation, shown in the Equation 1 below, was performed for the transmission and storage segment.

Equation 1

$$R_{PTS} = \frac{Comp_{New}^{PTS} (E_{G\&B} - E_{New}) \times C \times O \times 8760}{10^6}$$

where:

R_{PTS} = Potential methane emission reductions from transmission or storage compressors replacing rod packing, in million cubic feet per year (MMcf/year).

$Comp_{New}^{PTS}$ = Number of new transmission or storage compressors.

$E_{G\&B}$ = Methane emission factor for transmission or storage compressors in Table 7-2, in cubic feet per hour per cylinder.

E_{New} = Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder¹⁰³ for this analysis.

C = Average number of cylinders for transmission or storage compressors in Table 7-2.

O = Percent of time during the calendar year the average transmission or storage compressor is in the operating and standby pressurized modes, 79.1%, 67.5% respectively.

8760 = Number of days in a year.

10^6 = Number of cubic feet in a million cubic feet.

A summary of the potential emission reductions for reciprocating compressor rod packing replacement in the transmission and storage segment is presented in Table 7-4. The emissions of VOC were estimated using the methane emissions calculated above and the methane-to-VOC- ratio developed for each of the segments in the gas composition analysis conducted for the NSPS.¹⁰⁴

Table 7-4. Estimated Annual Reciprocating Compressor Emission Reductions from Replacing Rod Packing for a Typical Year

Compressor Location	Number of New Sources Per Year	Individual Compressor Emission Reductions (tons/compressor-year)		Nationwide Emission Reductions (tpy)	
		Methane	VOC	Methane	VOC
Typical Year					
Transmission	15	21.7	0.601	325	9
Storage	17	21.8	0.605	109	10

7.3.2.3 Cost Impacts

Costs for the replacement of reciprocating compressor rod packing were obtained from a Natural Gas STAR Lessons Learned document¹⁰⁵ which estimated the cost to replace the rod packing rings to be \$1,712 per cylinder. It was assumed that rod packing replacement would occur during planned shutdowns and maintenance and therefore, no travel costs will be incurred for implementing the rod packing replacement program. In addition, no costs were included for monitoring because the rod packing placement is based on number of hours that the compressor operates, or the time since the last replacement. The replacement of rod packing for reciprocating compressors occurs on average every four years based on industry information from the Natural Gas STAR Program.¹⁰⁶ The

¹⁰³ Ibid.

¹⁰⁴ See footnote 3.

¹⁰⁵ See footnote 102.

¹⁰⁶ Ibid.

cost impacts are based on the replacement of the rod packing every 26,000 hours that the reciprocating compressor operates in the pressurized mode.

For the 2012 NSPS, the number of hours used for the cost impacts was determined using a weighted average of the annual percentage that the reciprocating compressors are pressurized for all of the new sources. This percentage of hours is, on average, the number of hours per year a reciprocating compressor is pressurized and was used as the basis for the cost evaluation as it was determined to be the best available industry-wide percent pressurized value. The weighted average percentage was calculated to be 98.9 percent. This percentage was multiplied by the total number of hours in 3 years to obtain a value of 26,000 hours. This calculates to an average of 3.8 years for transmission compressors and 4.4 years for storage compressors using the operating factors in Table 7-2. The calculated years were assumed to be the equipment life of the compressor rod packing and were used to calculate the capital recovery factor for each of the segments. Assuming an interest rate of 7 percent, the capital recovery factors were calculated to be 0.3122 for transmission compressors and 0.2720 for storage compressors. The capital costs were calculated using the average rod packing cost of \$1,712 and the average number of cylinders per segment as presented in Table 7-2. The annual costs were calculated using the capital cost and the capital recovery factors.

The cost per ton of emissions reduced was then calculated in two ways. The first method, or single-pollutant approach, allocated all of the costs to each pollutant separately. The second method, or multi-pollutant approach, allocated costs among the pollutants that a given technology reduced (i.e., methane and VOC). The multi-pollutant approach was based on estimates of the percentage reduction expected for each pollutant. A summary of the capital and annual costs for the transmission and storage segment is shown in Table 7-5.

There are monetary savings associated with the amount of gas saved with reciprocating compressor rod packing replacement, however, these savings were not included in the cost estimates for the transmission and storage segment because it is assumed that the owner/operator of the compressor generally is not the owner of the natural gas that is compressed at their compressor stations.

Table 7-5. Cost of Control for Reciprocating Compressor Rod Packing Replacement (\$2012)

Compressor Location	Capital Cost (\$)	Annual Cost (\$/yr)	Cost of Control Single-Pollutant Approach (\$/ton)		Cost of Control Multi-Pollutant Approach (\$/ton)	
			Methane	VOC	Methane	VOC
Transmission	\$5,650	\$1,748	\$81	\$2,910	\$40	\$1,455
Storage	\$7,705	\$2,077	\$95	\$3,434	\$48	\$1,717

7.3.2.4 Secondary Impacts

The reciprocating compressor rod packing replacement is an option that prevents the escape of natural gas from the piston rod. No wastes should be created, no wastewater generated, and no maintenance of electrical systems and therefore, no travel costs will be incurred for implementing the rod packing replacement program. In addition, no costs were included for monitoring because the rod packing is replaced based on operating hours or time since the last replacement.

7.3.3 Centrifugal Compressor Dry Seals

7.3.3.1 Description

Centrifugal compressor dry seals operate mechanically under the opposing force created by hydrodynamic grooves and springs. The hydrodynamic grooves are etched into the surface of the rotating ring affixed to the compressor shaft. When the compressor is not rotating, the stationary ring in the seal housing is pressed against the rotating ring by springs. When the compressor shaft rotates at high speed, compressed gas has only one pathway to leak down the shaft, and that is between the rotating and stationary rings. This gas is pumped between the rings by grooves in the rotating ring. The opposing force of high-pressure gas pumped between the rings and springs trying to push the rings together creates a very thin gap between the rings through which little gas can leak. While the compressor is operating, the rings are not in contact with each other, and therefore, do not wear or need lubrication. O-rings seal the stationary rings in the seal case.

Dry seals substantially reduce gas emissions compared to wet seals. At the same time, they significantly reduce operating costs and enhance compressor efficiency compared to wet seals. Economic and environmental advantages of using dry seals include:

- Gas Leak Rates. During normal operation, dry seals leak at a rate of less than 6 scfm methane per compressor.¹⁰⁷ While this is equivalent to a wet seal's leakage rate at the seal face, wet seals generate additional emissions during degassing of the circulating oil. Gas separated from the seal oil before the oil is re-circulated is usually vented to the atmosphere bringing the total leakage rate for tandem wet seals to 47.7 scfm methane per compressor.^{108, 109}
- Mechanically Simpler. Dry seal systems do not require additional oil circulation components and treatment facilities.
- Reduced Power Consumption. Because dry seals have no accessory oil circulation pumps and systems, they avoid "parasitic" equipment power losses. Wet seal systems require 50 to 100 kilowatt (kW) per hour, while dry seal systems need about 5 kW of power per hour.
- Improved Reliability. The highest percentage of downtime for a compressor using wet seals is due to seal system problems. Dry seals have fewer ancillary components, which translates into higher overall reliability and less compressor downtime.
- Lower Maintenance. Dry seal systems have lower maintenance costs than wet seals because they do not have moving parts associated with oil circulation (e.g., pumps, control valves, relief valves, and the seal oil cost itself).
- Elimination of Oil Leakage from Wet Seals. Substituting dry seals for wet seals eliminates seal oil leakage into the pipeline, thus avoiding contamination of the gas and degradation of the pipeline.

6.3.3.2 Emissions Reduction Potential

The emission reduction of the dry seal compressor was calculated by subtracting the dry seal emissions from the emissions from a centrifugal compressor equipped with wet seals. The centrifugal compressor emission factors in Table 7-2 were used in combination with an operating factor of 30 percent for transmission centrifugal compressors and 22.4 percent for storage centrifugal

¹⁰⁷ U.S. EPA. Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors. October 2006. Available at http://epa.gov/gasstar/documents/ll_wetseals.pdf.

¹⁰⁸ "Methane's Role in Promoting Sustainable Development in the Oil and Natural Gas Industry". US EPA, ICF International, PEMEX, EnCana Oil & Gas, Hy-Bon Engineering, Pluspetrol, Gazprom, VNIIGAZ. World Gas Conference 10/2009. Available at http://www.epa.gov/gasstar/documents/best_paper_award.pdf.

¹⁰⁹ U.S. Environmental Protection Agency. Methodology for Estimating CH₄ and CO₂ Emissions from Petroleum Systems. Greenhouse Gas Inventory: Emission and Sinks 1990-2009. Washington, DC. April, 2011. Annex 3. Page A-153.

compressors. The operating factors are used to account for the percent of time in a year that a compressor is in the operating mode. The operating factors are based on data from the GHG Inventory.¹¹⁰ The wet seals emission factor is an average of 48 different wet seal centrifugal compressors. The dry seal emission factor is based on information from the Natural Gas STAR Program.¹¹¹ A summary of the emission reduction from the replacement of wet seals with dry seals is shown in Table 7-6.

Table 7-6. Estimated Annual Centrifugal Compressor Emission Reductions from Replacing Wet Seals with Dry Seals

Compressor Location	Number of New Sources Per Year	Individual Compressor Emission Reductions (ton/compressor-year)		Nationwide Emission Reductions (tpy)	
		Methane	VOC	Methane	VOC
Transmission	0	137	3.79	0	0
Storage	1	102	2.83	102	2.83

7.3.3.3 Cost Impacts

The price difference between a brand new dry seal and brand new wet seal centrifugal compressor is insignificant relative to the cost for the entire compressor. From the Natural Gas STAR Program, General Electric (GE) stated that a natural gas transmission pipeline centrifugal compressor with dry seals cost between \$50,000 and \$100,000 more than the same centrifugal compressor with wet seals. However, this price difference is only about 1 to 3 percent of the total cost of the compressor. The price of a brand new natural gas transmission pipeline centrifugal compressor between 3,000 and 5,000 horsepower runs between \$2 million to \$5 million depending on the number of stages, desired pressure ratio, and gas throughput. The larger the compressor, the less significant the price difference is between dry seals and wet seals. This analysis assumes the additional capital cost for a dry seal compressor is \$75,000 (\$79,268 in 2012 dollars). The annual cost was calculated as the capital recovery of this capital cost assuming a 20-year equipment life and 7 percent interest which came to \$7,482 per compressor. The Natural Gas STAR Program estimated that the annual operation and maintenance savings from the installation of dry seal compressor is \$88,300 in comparison to wet seal compressor. The cost per ton of emissions reduced was then

¹¹⁰ See footnote 4.

¹¹¹ U.S. EPA. Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors. Natural Gas STAR. 2006.

calculated in two ways. The single-pollutant method allocated all of the costs to each pollutant separately. The multi-pollutant method prorated costs among the pollutants that a given technology reduced (i.e., methane and VOC). The multi-pollutant method was based on estimates of the percentage reduction expected for each pollutant. A summary of the capital and annual costs for dry seals is presented in Table 7-7 along with the methane and VOC cost of control for the dry seal compressor option. We do not consider revenues from gas savings for transmission and storage facilities because it is assumed the owners of the compressor station do not own the natural gas that is compressed at the station.

Table 7-7. Cost of Reductions for Centrifugal Compressor Using Dry Seal Compressors (\$2012)

Compressor Location	Capital Cost (\$)	Annual Cost Per Compressor (\$/compressor-year)		Methane Cost of Control (\$/ton)		VOC Cost of Control (\$/ton)	
		without savings	with O&M savings	without savings	with O&M savings	without savings	with O&M savings
Single-Pollutant							
Transmission	\$79,268	\$7,482	-\$85,843	\$55	-\$627	\$1,974	-\$22,642
Storage	\$79,268	\$7,482	-\$85,843	\$73	-\$840	\$2,643	-\$30,324
Multi-Pollutant Method							
Transmission	\$79,268	\$7,482	-\$85,843	\$27	-\$314	\$987	-\$11,321
Storage	\$79,268	\$7,482	-\$85,843	\$37	-\$420	\$1,322	-\$15,162

7.3.3.4 Secondary Impacts

Dry seals for centrifugal compressors are an option that prevents the escape of natural gas across the rotating compressor shaft. No wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to the installation of dry seals on centrifugal compressors.

7.3.4 Centrifugal Compressor Wet Seals Routed to a Combustion Device

7.3.4.1 Description

Another control option used to reduce emissions from centrifugal compressors equipped with wet seals is to route the emissions to a combustion device or capture the emissions and route them to a process (e.g., a fuel system). A wet seal system uses oil that is circulated under high pressure between three rings around the compressor shaft, forming a barrier against the compressed gas. The

center ring is attached to the rotating shaft, while the two rings on each side are stationary in the seal housing, pressed against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. Compressed gas becomes absorbed and entrained in the fluid barrier and is removed using a heater, flash tank, or other degassing technique so that the oil can be recirculated back to the wet seal. The removed gas is either combusted or released to the atmosphere. The control technique investigated in this section is the use of wet seals with the removed gas sent to a combustion device or to a process.

7.3.4.2 Emissions Reduction Potential

Combustion devices have been used in the oil and natural gas industry to combust gas streams that have VOC and organic HAP. A combustion device typically achieves 95 percent reduction of these compounds when operated according to the manufacturer instructions. For this analysis, it was assumed that the entrained gas from the seal oil that is removed in the degassing process would be directed to a combustion device that achieves 95 percent reduction of methane, VOC, and organic HAP. The wet seal emissions in Table 7-2 were used along with the control efficiency to calculate the emission reductions from this option. A summary of the emission reductions is presented in Table 7-8.

Table 7-8. Estimated Annual Centrifugal Compressor Emission Reductions from Wet Seals Routed to a Combustion Device

Compressor Station	Number of New Sources Per Year	Individual Compressor Emission Reductions (tons/compressor-year)		Nationwide Emission Reductions (tpy)	
		Methane	VOC	Methane	VOC
Transmission	0	149	4.12	0	0
Storage	1	111	3.08	111	3.08

7.3.4.3 Cost Impacts

The capital and annual cost of the combustion device (an enclosed flare for the analysis) was calculated using the methodology in the EPA Control Cost Manual.¹¹² The heat content of the gas stream was calculated using information from the gas composition memorandum.¹¹³ A summary of

¹¹² EPA Air Pollution Control Cost Manual - Sixth Edition, (EPA 452/B-02-001).

¹¹³ See footnote 3.

the capital and annual costs for wet seals routed to a flare is presented in Table 7-9. The cost per ton of emissions reduced was then calculated in two ways. The single-pollutant approach allocated all of the costs to each pollutant separately. The multi-pollutant approach allocated costs among the pollutants that a given technology reduced (i.e., methane and VOC). This allocation was based on estimates of the percentage reduction expected for each pollutant. The methane and VOC cost of control for the wet seals routed to a combustion device option is also shown in Table 7-9. There is no cost savings estimated for this option because the recovered gas is combusted.

Table 7-9. Cost of Control for Centrifugal Compressor Wet Seal Emission Routed to a Combustion Device

Compressor Location	Capital Cost (\$)		Annual Cost per Compressor (\$/compressor-year)		Cost of Control New CD (\$/ton)		Cost of Control Existing CD (\$/ton)	
	New CD	Existing CD	New CD	Existing CD	Methane	VOC	Methane	VOC
Single-Pollutant								
Transmission	\$71,783	\$23,252	\$114,146	\$3,311	\$767	\$27,705	\$22	\$804
Storage	\$71,783	\$23,252	\$114,146	\$3,311	\$1,028	\$37,105	\$30	\$1,076
Multi-Pollutant Method								
Transmission	\$71,783	\$23,252	\$114,146	\$3,311	\$384	\$13,853	\$11	\$402
Storage	\$71,783	\$23,252	\$114,146	\$3,311	\$514	\$18,553	\$15	\$538

CD = Control Device

7.3.4.4 Secondary Impacts

There are secondary impacts with the option to use wet seals with a combustion device. The combustion of the recovered gas creates secondary emissions of hydrocarbons (NO_x, CO₂, and CO emissions). A summary of the estimated secondary emission are presented in Table 7-10. No other wastes should be created or wastewater generated.

Table 7-10. Secondary Impacts from Wet Seal Emissions Routed to a Combustion Device

Compressor Location	Secondary Impacts from Wet Seals Routed to a Combustion Device (tpy)				
	THC ^a	CO ^b	CO ₂ ^c	NO _x ^d	PM ^e
Transmission	0	0	0	0	0
Storage	0.58	1.29	550	0.28	0.01

a. Based on combustion of natural gas stream and AP-42 Total Hydrocarbons emission factors for industrial flares.

b. Based on combustion of natural gas stream and AP-42 Carbon Monoxide emission factors for industrial flares.

c. Based on combustion of natural gas stream and 40 CFR Part 98, subpart Y, Equation Y-2.

d. Based on combustion of natural gas stream and AP-42 Nitrogen Oxides emission factors for industrial flares.

e. Based on combustion of natural gas stream and AP-42 Particulate Matter emission factors for industrial flares.

Assumes a “lightly smoking” flare.

7.4 Regulatory Options

EPA evaluated the following regulatory options:

- Regulatory Option 1. Require replacement of the reciprocating compressor rod packing based on 26,000 hours of operation while the compressor is pressurized.
- Regulatory Option 2. Require all centrifugal compressors to be equipped with dry seals.
- Regulatory Option 3. Require centrifugal compressors equipped with a wet seal to route the recovered gas emissions to a combustion device.

7.4.1 Evaluation of Regulatory Options

The first regulatory option for replacement of the reciprocating compressor rod packing based on the number of hours that the compressor operates in the pressurized mode was described in Section 7.3.1. The methane and VOC cost of control for reciprocating compressors at transmission stations is \$81 and \$2,910 per ton, respectively. The methane and VOC cost of control for reciprocating compressors at storage facilities is \$95 and \$3,434 per ton, respectively. Based on these cost of control values for methane, EPA selected Regulatory Option 1 for the transmission and storage segment.

The second regulatory option would require all centrifugal compressors to be equipped with dry seals. As presented in Section 7.3.2, dry seals are effective at reducing emissions from the rotating shaft of a centrifugal compressor. Dry seals also reduce operation and maintenance costs in

comparison to wet seals. Under the single pollutant approach, the methane and VOC cost of emission reductions for dry seals compressors was calculated to be \$55 per ton and \$1,974 per ton respectively for centrifugal compressors located at transmission facilities, not including the savings from operation and maintenance costs. When those savings were considered the methane and VOC cost of control was calculated to be (\$627) per ton and (\$22,642) per ton. Also under the single pollutant approach, the methane and VOC cost of control for dry seal compressors was calculated to be \$73 per ton and \$2,643 per ton respectively for centrifugal compressors located at storage facilities, not including the savings from operation and maintenance costs.¹¹⁴ When those savings were considered, the methane and VOC cost of control was calculated to be (\$840) per ton and (\$30,324) per ton. However, commenters on the 2011 Oil and Natural Gas NSPS noted that are certain situations where installing a dry seal system is not feasible, such as where gas composition is inadequate and in retrofits of some existing compressors due to housing design or operational requirements. Therefore, EPA rejected Regulatory Option 2 as a regulatory option for centrifugal compressors located at transmission or storage facilities.

The third regulatory option would allow the use of wet seals if the recovered gas emissions were routed to a combustion device or process. Under the single pollutant approach, the methane and VOC cost of control for routing emissions from a wet seal system to a combustion device was calculated to be \$767 per ton and \$27,705 per ton respectively for centrifugal compressors located at transmission facilities. Also under the single pollutant approach, the methane and VOC cost of control for routing emissions from a wet seal system to a combustion device was calculated to be \$1,028 per ton and \$37,105 per ton respectively for centrifugal compressors located at transmission facilities. However, facilities may already have a combustion device operating at the facility or would route the captured gas back to a useful process rather than flaring it. Those facilities would not incur the additional capital cost and operation and maintenance costs of the flare. Under the single pollutant approach for those facilities the methane and VOC cost of control were calculated to be \$22 per ton and \$804 per ton respectively for transmission facilities and \$30 per ton and \$1,076 per ton respectively for storage facilities. Based on these cost of control values, EPA is selecting Regulatory Option 3 for the transmission and storage segment.

¹¹⁴ Negative cost is the result of operation and maintenance savings for dry seals.

VOLUME 2: NATIONAL LEVEL IMPACTS

8.0 NATIONWIDE IMPACTS FOR HYDRAULICALLY FRACTURED OIL WELL COMPLETIONS AND RECOMPLETIONS

8.1 Nationwide Emissions

8.1.1 Determination of Number of Completions and Recompletions

The first step in this analysis is to estimate nationwide baseline emissions in 2012, the year selected as the baseline year. In order to develop the baseline emissions, the EPA estimate the average number of wells that would be affected using the number of completions and recompletions performed in a typical year derived from the DrillingInfo database extract as described above. This value was then multiplied by the potential uncontrolled emissions per well completion listed in Table 3-2.

The DrillingInfo database includes the most recent completion date for all reported wells in the US. Therefore, the methodology described above for calculating the number of hydraulically fractured oil well completions from the HPDI® database in 2012 identifies wells initially fractured in 2012 and wells that were refractured (recompletions) in 2012. Because these recompletions are included in the database and resulting extracted dataset, it is not necessary to calculate a refracture frequency.

To more accurately estimate baseline emissions for this analysis, and to ensure no emission reductions were calculated for sources already being controlled, it was necessary to evaluate the number of completions and recompletions already subject to regulation. The number of completions and recompletions already being controlled in the absence of federal regulation was estimated based on the existing state regulations that require control measures for completions and recompletions. Although there may be regulations issued by other local ordinances for cities and counties throughout the U.S., the number of wells impacted by local (as opposed to state level) regulations could not be determined because data for wells subject to county or local ordinance level regulations are not available. Therefore, the calculated percentage of wells subject to state regulation based on the identified state regulations should be considered a conservative estimate.

In order to determine the number of completions and recompletions that are already controlled under state regulations, the DrillingInfo database extract well count data (described

above) was analyzed to determine the percentage of new wells currently undergoing completion and recompletion in the states identified as having existing controls. In our proposal, the EPA identified Colorado, and Wyoming as the only states requiring controls on completions comparable to the NSPS requirements prior to NSPS review. The State of Wyoming's Air Quality Division (WAQD) requires operators to complete wells without flaring or venting where the following criteria are met: (1) the flowback gas meets sales line specifications and (2) the pressure of the reservoir is high enough to enable REC. If the above criteria are not met, then the produced gas is to be flared.¹¹⁵ The WAQD requires that, "emissions of VOC and HAP associated with the flaring and venting of hydrocarbon fluids (liquids and gas) associated with well completion and recompletion activities shall be eliminated to the extent practicable by routing the recovered liquids into storage tanks and routing the recovered gas into a gas sales line or collection system." Similar to Wyoming, the Colorado Oil and Gas Conservation Commission (COOGCC) requires a renewable energy certificate (REC) for both oil and natural gas wells.¹¹⁶ It was assumed for proposal that the ratio of wells in Colorado and Wyoming to the total number of wells in the U.S. represents the percentage of controlled wells for well completions. The ratio of wells in Wyoming to the number of total nationwide wells was assumed to represent the percentage of controlled well recompletions as it was the only state identified as having regulations directly related to recompletions. The EPA used the referenced GOR of less than (<) 100,000 scf/bbl for oil wells to identify the oil wells located in Wyoming and Colorado. From this review it was estimated that 8.81 percent of oil well completions are controlled in absence of federal regulation.

The EPA received significant comment that the proposal did not consider the existing control requirements for a then-proposed, now-final requirements in North Dakota that requires flaring of all emissions during the flowback stage of completions. In particular, the North Dakota Air Pollution Control Rules require that all organic gases and vapors be burned by flares and the North Dakota Industrial Commission requires that all vented casinghead gas be burned, pending arrangements for disposition for some useful purpose.¹¹⁷ Considering the comments, for the final

¹¹⁵ Wyoming BACT permitting guidance. Available at http://deq.state.wy.us/aqd/Oil%20and%20Gas/September%202013%20FINAL_Oil%20and%20Gas%20Revision_UGRB.pdf.

¹¹⁶ COGCC 805 Series Rules (805.b.(3)A). Available at <http://cogcc.state.co.us/> and the Colorado Code of Regulations at: <http://www.sos.state.co.us/CCR/Welcome.do>.

¹¹⁷ N.D. Admin. Code§ 33-15-07-02(1) and§ 43-02-03-45

rule, the EPA determined that the percentage of completions and recompletions conducted in North Dakota for oil wells greater than or equal to 300 GOR was 9.4 percent.

Finally, the EPA determined the number of exploratory oil well completions based on the percentage breakdown between exploratory and development wells in the National Energy Modeling System (NEMS). NEMS is a model of the U.S. energy economy developed and maintained by the EIA. NEMS is used to produce the Annual Energy Outlook (AEO), a reference publication that provides detailed forecasts of the energy economy from the current year to 2040. The NEMS source code is publicly available and fully documented. The source code and accompanying documentation is released annually when a new AEO is produced. Because of the availability of NEMS, numerous agencies, national laboratories, research institutes, and academic and private-sector researchers have used NEMS to analyze a variety of issues. NEMS models the dynamics of energy markets and their interactions with the broader U.S. economy. Based on the NEMS AEO 2014 Reference Case, 3.8 percent of oil wells are exploratory and 96.2 percent are development wells.

In addition, as for the development of the 2012 NSPS for gas well completions, the EPA is aware that some oil well completions and workovers are controlled voluntarily using RECs or combustion devices. However, the EPA could not identify a national level data source on this practice from which the EPA could estimate the numbers of voluntarily controlled oil well completions. Therefore, due to lack of data and a reliable benchmark for estimating the number of voluntarily controlled completions, the EPA assumed zero for our analysis of baseline emissions.

In order to determine nationwide impacts of the number of new oil well completions and recompletions, the EPA used the base year of 2012 activity data (see the 2015 Proposal TSD for details on the 2012 base year projection) as described above and projected activity numbers for the years 2020 and 2025 based on predictions from the NEMS Oil and Gas Supply Model. The EPA calculated the compound annual growth rate (CAGR) between 2012 and 2015 for development and exploratory oil wells based on the AEO 2015 Reference Case. The CAGR for development wells was found to be -0.1 percent and the CAGR for exploratory wells was found to be 6.2 percent. These factors were used to calculate the number of exploratory and development oil well completion for the years 2020 and 2025.

Table 8-1 summarizes the estimated number of hydraulically fractured oil well completions derived from our analysis detailed above.

Table 8-1. Estimated Number of Hydraulically Fractured Oil Well Completions and Recompletions - 2020 and 2025

Hydraulically Fractured Oil Well Completions	2020	2025
Total Oil Well Completions and Recompletions	19,703	20,988
<i>Total with < 300 GOR</i>		
Development	4,481	4,774
Exploratory/Delineation	177	188
<i>Total with ≥ 300 GOR</i>		
Development	13,862	14,730
Exploratory/Delineation	1,183	1,296
<i>Total with ≥ 300 GOR and Regulated by States (CO and WY) (Comparable to NSPS)</i>		
Development	1,100	1,168
Exploratory/Delineation	92	101
<i>Total with ≥ 300 GOR and Regulated by States (ND) (Flaring only)</i>		
Development	1,200	1,275
Exploratory/Delineation	103	112
<i>Total with ≥ 300 GOR, Not Regulated by States (CO and WY)</i>		
Development	12,762	13,562
Exploratory/Delineation	1,091	1,195

Because the proposed and final rule requirements affect oil well completions and recompletions differently, particularly where activities are currently controlled under a state regulation, the EPA estimated the number of projected well completions and recompletions which would be affected under different control scenarios under the NSPS. Specifically, the EPA calculated activity numbers for the following control scenarios:

- Development oil wells that are greater than or equal to 300 GOR which are currently venting and are capable of conducting a REC combined with combustion. This number is the number of new development oil well completions and recompletions that are not covered by a state regulation in CO or WY (i.e., 12,762 in 2020 and 13,562 in 2015) and not located in ND and that are capable of conducting a REC. The EPA estimate that 50 percent of these oil wells are capable of conducting a REC.
- Development oil wells that are greater than or equal to 300 GOR and are currently venting, however, it is technically infeasible for them to conduct a REC, therefore combust emissions. This number is the number of new development oil well completions and recompletions that are not covered by state regulation in CO or WY (i.e., 12,762 in 2020 and

13,562 in 2025) and are not located in ND and that are not capable of conducting a REC due to technical infeasibility reasons (other than low pressure). See the discussion in 3.3.2.1 with respect to technical infeasibility as being reasons for not being required to conduct a REC. The EPA estimates that 10 percent of these oil wells are not capable of conducting a REC.

- Development oil wells that are greater than or equal to 300 GOR and are currently venting, however, due to low pressure cannot conduct a REC, and therefore combust emissions. This number is the number of new development oil well completions and recompletions that are not covered by state regulation in CO or WY (i.e., 12,762 in 2020 and 13,562 in 2025) and are not located in ND and that are not capable of conducting a REC due to low pressure. As discussed in section 8.2.1 below, the EPA estimate that 40 percent of these oil wells are not capable of conducting a REC.
- Development oil wells that are greater than or equal to 300 GOR and are currently flaring based on state requirements that are capable of conducting a REC combined with combustion. This number is the number of new development oil well completions and recompletions that are not covered by state regulation in CO or WY (i.e., 12,762 in 2020 and 13,562 in 2025) and are located in ND and that are capable of conducting a REC. As discussed in section 8.2.1 below the EPA estimate that 50 percent of these oil wells are capable of conducting a REC.
- All other development oil wells. This number is the development oil wells that are less than 300 GOR plus the greater than or equal to 300 GOR oil wells that are located in ND that are currently flaring and incapable of conducting a REC, plus the greater than or equal to 300 GOR oil wells that are controlled based on state regulation. This scenario results in no change in control status based on the NSPS.
- Exploratory and delineation oil wells that are greater than or equal to 300 GOR and are currently venting which would now be required to combust emissions. This is the number of exploratory and delineation oil wells that are not covered by state regulation in CO or WY and that are not located in ND. The EPA assumes that 100 percent of these wells are venting.
- All other exploratory and delineation oil wells. This number is the exploratory/delineation oil wells that are less than 300 GOR plus the greater than or equal to 300 GOR oil wells that are located in ND that are currently flaring and incapable of conducting a REC plus the

greater than or equal to 300 GOR oil wells that are controlled based on state regulation. This scenario results in no change in control status based on the NSPS.

Table 8-2 summarizes the estimates of the numbers of oil well completions and recompletions based on these control scenarios above.

Table 8-2. Estimated Number of Total Oil Well Completions and Recompletions by Control Scenario under the NSPS for 2020 and 2025

Estimated Control Scenario Under NSPS	2020	2025
Development Oil Wells (Venting/REC with Combustion)	5,781	6,144
Development Oil Wells (Venting/TI for REC, Combustion)	1,156	1,229
Development Oil Wells (Venting, LP/Combustion)	4,625	4,915
Development Oil Wells (Flaring/REC)	600	637
Development Oil Wells (No change)	6,181	6,580
Exploratory/Delineation Oil Wells (Venting/Combustion)	988	1,083
Exploratory/Delineation Oil Wells (No change)	372	401

REC = Reduced Emissions Completion, TI for REC, Combustion = Technical infeasibility for a REC, combustion required, LP = Low pressure well

8.1.2 Nationwide Emission Estimates

Using the estimated emissions per source as shown in Table 3-2, number of uncontrolled and controlled wells at baseline, described above, nationwide emission estimates for oil well completions and recompletions in the base year 2012 and projected completions and recompletions for the projected years 2020 and 2025 were calculated and are summarized in Table 8-3. All values have been rounded to the nearest ton for estimation purposes.

Table 8-3. Nationwide Baseline Emissions for 2020 and 2025 from Hydraulically Fractured Oil Well Completions and Recompletions

Well Source Subcategory	Emissions Per Event (tpy)		Number of Uncontrolled Wells ^a	Baseline Nationwide Emissions (tpy)	
	Methane	VOC		Methane ^b	VOC ^b
Projected Year 2020					
All Oil Wells	9.72	8.14	13,853	122,279	102,396
1. Developmental Oil Wells	9.72	8.14	12,162	112,672	94,351
2. Exploratory/Delineation Oil Wells	9.72	8.14	988	9,607	8,045
Projected Year 2025					
All Oil Wells	9.72	8.14	14,007	130,257	109,078
1. Developmental Oil Wells	9.72	8.14	12,925	119,734	100,266
2. Exploratory/Delineation Oil Wells	9.72	8.14	1,083	10,523	8,812

a. The number of controlled wells is equal to all wells less wells controlled based on state regulations in ND, CO and WY.

b. Based on the assumption that VOC content is 0.8374 lbs VOC per pound methane. This estimate accounts for 5 percent of emissions assumed as vented even when controlled. These values do not account for secondary emissions from portion of gas that is directed to a combustion device.

8.2 Nationwide Impacts of the Final Rule (for purposes of Regulatory Impact Analysis)

This section provides an analysis of the primary environmental impacts (i.e., emission reductions), cost impacts and secondary environmental impacts related to final standards for oil well completions and recompletions. See the rule package for details of the final standards.

8.2.1 Primary Environmental Impacts of Regulatory Options

The selected standards for oil well completions and recompletions are as follows:

- Subcategory 1 - Development (i.e., wells which do not meet the definition of exploratory or delineation wells) Oil Well Completions and Recompletions: Operational standard for completions and recompletions with hydraulic fracturing which requires a combination of REC with combustion, but allows for combustion alone or venting during specified situations.
- Subcategory 2 - Exploratory and Delineation Oil Well Completions and Recompletions: An operational standard for completions and recompletions with hydraulic fracturing which requires completion combustion devices with an allowance for venting during specified situations.

As noted in section 3.3.1 above, there are several control scenarios under which an oil well might be affected under the NSPS. The number of completions and recompletions that would be subject to the various regulatory requirements under the NSPS is listed in Table 8-3.

Table 8-4 summarizes the nationwide emission reduction estimates for each of the estimated control scenarios for the projected years 2020 and 2025. It was estimated that RECs in combination with the combustion of gas unsuitable for entering the gathering line, can achieve an overall 95 percent VOC reduction over the duration of the completion or recompletion operation. The 95 percent recovery was estimated based on 90 percent of flowback being captured to the sales line and assuming an additional 5 percent of the remaining flowback would be sent to the combustion device. Additionally, where it is technically infeasible to conduct a REC, the EPA estimated a 95 percent emission reduction as the result of combustion where required. As discussed in section 3.3.2.1 above, there are several instances where conducting a REC is not feasible. The EPA estimate, for the purposes of estimating impacts that 50 percent of oil wells will be capable of conducting a REC and that 40 percent of the oil wells will not be able to conduct a REC due to low pressure in the well. Another 10 percent of the oil wells are estimated to not be able to conduct a REC due to other technical infeasibility such as access to gas lines, inert gas concentration, safety or other hazards where the separator cannot be operated. Nationwide emission reductions were estimated by applying this 95 percent reduction to the uncontrolled baseline emissions presented in Table 3-2.

8.2.2 *Nationwide Cost Impacts*

The operational standards for development wells that can conduct a REC include both REC and a completion combustion device, therefore the total incremental cost of the operational standard for developmental oil well completions and for recompletions is estimated at around \$17,183, which includes the costs in Table 3-3 for the REC equipment and transportation in addition to the cost for the completion combustion device. The cost for a completion combustion device alone is estimated to be \$3,723. The cost for addition of REC equipment to a site that is already combusting emissions is estimated to be \$13,459.

For the projected year 2020, applying the cost for the combined REC with completion combustion device to the estimated 5,781 oil wells that are estimated to be capable of conducting a REC, the total nationwide cost was estimated to be approximately \$78.5 million, which includes an estimated annual savings of approximately \$20.8 million when natural gas savings are considered. Likewise, for projected year 2025, the cost for RECs with combustion device applied to 6,144

development oil well completions and recompletions, the total nationwide cost was estimated to be approximately \$83.5 million, including annual savings estimated at around \$22.1 million when natural gas savings are considered.

For development oil wells not capable of conducting a REC due to technical infeasibility, the cost of a REC and combustion control device applied to the 1,156 completions in 2020 and the 1,229 completions in 2025, the nationwide cost was estimated to be approximately \$19.9 million and \$21 million respectively. These completions have no gas savings because the separator is estimated to not be able to function and therefore no gas will be able to be recovered. Finally, for wells that are currently flaring emissions, the EPA estimate 600 wells in 2020 and 637 wells in 2025. The nationwide costs for addition of REC to these completions are approximately \$5.9 million in 2020 and \$6.3 million in 2025 which includes gas savings of approximately \$2.2 million and \$2.3 million, respectively.

For development oil wells that meet the definition of low pressure wells, the standard requires combustion of emissions and a separator is not required to be onsite.¹¹⁸ Therefore, the EPA apply the cost of a combustion control device to the estimated 4,625 low pressure oil wells estimated for the year 2020 and the estimated 4,915 for the year 2025, the nationwide cost was estimated to be approximately \$17.2 million and \$18.3 million respectively. The total nationwide cost estimated for development oil well completions is approximately \$121.7 million for the year 2020 (including \$23 million in gas savings) and \$129.2 million for the year 2025 (including \$24.4 million in gas savings).

For exploratory and delineation oil well completions, the EPA apply the cost of a combustion control device to the 988 oil well completions estimated for the year 2020 and the 1,083 oil wells estimated for the year 2025, and the nationwide costs associated with exploratory and delineation oil well completions is approximately \$3.7 million for 2020 and \$4 million for 2025. Table 8-4 summarizes the estimated nationwide emission reductions and costs for each of these control scenarios.

¹¹⁸ Note that for the final rule the low pressure well definition has been revised. See Appendix A for a full discussion of the revised low pressure well definition.

Table 8-4. Nationwide Emission and Cost for Control Scenarios under the Final Subpart OOOOa

Well Completion Category (Current status/Rule Requirement)	Number of Sources Subject to NSPS ^a	Annual Cost Per Completion Event ^b	Nationwide Emission Reductions ^c				Total Nationwide Costs	
			(tpy)				(\$/year)	
		(\$)	Methane	VOC	HAP	CO2e ^d	without savings	with savings ^e
Projected Year 2020								
Development Oil Wells (Venting/REC with Combustion)	5,781	\$17,183	53,379	44,699	5.3	1,210,611	\$99,333,820	\$78,539,011
Development Oil Wells (Venting/TI for REC, Combustion)	1,156	\$17,183	10,674	8,938	1.1	242,080	\$19,863,327	\$19,863,327
Development Oil Wells (Venting, LP/Combustion)	4,625	\$3,723	42,705	35,761	4.3	968,531	\$17,221,179	\$17,221,179
Development Oil Wells (Flaring/REC)	600	\$13,459	0	0	0	0	\$8,075,587	\$5,917,329
Development Oil Wells (No change)	6,181	\$0	0	0	0	0	0	0
Exploratory/Delineation Oil Wells (Venting/Combustion)	988	\$3,723	9,123	7,639	0.9	206,899	\$3,678,816	\$3,678,816
Exploratory/Delineation Oil Wells (No change)	372	\$0	0	0	0	0	0	0
Total	19,703	N/A	115,880	97,038	12	2,628,121	148,172,729	125,219,662

Well Completion Category (Current status/Rule Requirement)	Number of Sources Subject to NSPS ^a	Annual Cost Per Completion Event ^b	Nationwide Emission Reductions ^c				Total Nationwide Costs	
			(tpy)				(\$/year)	
		(\$)	Methane	VOC	HAP	CO2e ^d	without savings	with savings ^e
Projected Year 2025								
Development Oil Wells (Venting/REC with Combustion)	6,144	\$17,183	56,731	47,506	5.7	1,286,627	\$105,571,180	\$83,470,625
Development Oil Wells (Venting/ TI for REC, Combustion)	1,229	\$17,183	11,348	9,503	1.1	257,367	\$21,117,672	\$21,117,672
Development Oil Wells (Venting, LP/Combustion)	4,915	\$3,723	45,383	38,003	4.5	1,029,260	\$18,300,993	\$18,300,993
Development Oil Wells (Flaring/REC)	637	\$13,459	0	0	0	0	\$8,573,581	\$6,282,231
Development Oil Wells (No change)	6,580	\$0	0	0	0	0	0	0
Exploratory/Delineation Oil Wells (Venting/Combustion)	1,083	\$3,723	10,000	8,374	1.0	226,793	\$4,032,548	\$4,032,548
Exploratory/Delineation Oil Wells (No change)	401	\$0	0	0	0	0	0	0
Total	20,989	N/A	123,461	103,386	12	2,800,048	157,595,975	133,204,070

REC = Reduced Emissions Completion, TI for REC, Combustion = Technically infeasible to conduct REC, combustion required, LP = Low pressure wells

a. As presented in Table 4-43.

b. From Table 4-6.

c. Assumes no emission reductions for wells controlled by state regulation in CO, WY, and ND.

d. Assumes 0.90718474 metric tonnes per short ton and global warming potential of methane = 25.

e. Assumes savings only for scenarios where REC is performed.

8.3 Nationwide Secondary Impacts

Regulatory Options 3 and 4 require some amount of combustion; therefore the estimated nationwide secondary impacts are a direct result of combusting all or partial flowback emissions. Although it is understood that the volume of gas captured, combusted and vented may vary significantly depending on well characteristics and flowback composition, for the purpose of estimating secondary impacts for Regulatory Options 3 and 4, it was assumed that 90 percent of flowback is captured and an additional 5 percent of the remaining gas is combusted. For Subcategory 1 oil well completions and recompletions with hydraulic fracturing, it is assumed around 50 Mcf (5 percent of 999 Mcf) of natural gas is combusted on a per well basis when a REC is performed. For Regulatory Option 3 for Subcategory 1 oil wells where combustion is used for control and for Regulatory Option 4 for Subcategory 2 oil well completions and recompletions with hydraulic fracturing, it is assumed that 949 Mcf (95 percent of 999 Mcf) of flowback emissions are combusted by the combustion device. The impacts of pollutant emissions per completion event was estimated assuming 1,089.3 Btu/scf saturated gross heating value of the "raw" natural gas and applying the AP-42 emissions factors listed in Table 3-5.

For the projected year 2020, for Subcategory 1 well completions and recompletions controlled by a REC combined with a combustion device, it is estimated 0.002 tons of NO_x are produced per event. This is based on assumptions that 5 percent of the flowback gas is combusted by the combustion device. For subcategory 1 and subcategory 2 well completions controlled with a combustion device alone, it is estimated 0.37 tons of NO_x are produced in secondary emissions per event. This is based on the assumption 95 percent of flowback gas is combusted by the combustion device. Based on the estimated number of completions and recompletions for projected year 2020, the proposed regulatory options are estimated to produce around 300 tons of NO_x in secondary emissions nationwide from controlling all or partial flowback by combustion. Table 8-5 summarizes the estimated secondary emissions of the selected regulatory options for projected year 2020 and Table 8-6 summarizes the estimated secondary emissions of the selected regulatory options for projected year 2025.

Table 8-5. Nationwide Secondary Impacts of Selected Regulatory Options for Projected Year 2020^a

Pollutant	Regulatory Option 3 ^{b,c}				Regulatory Option 4 ^d		Combined Options
	1. Developmental Oil Well - REC		1. Developmental Oil Well - Combustion		2. Exploratory/Delineation Oil Well		
	Emissions per Completion Event (tons)	Nationwide Secondary Emissions (tpy)	Emissions per Completion Event (tons)	Nationwide Secondary Emissions (tpy)	Emissions per Completion Event (tons)	Nationwide Secondary Emissions (tpy)	Nationwide Secondary Emissions (tpy)
THC	0.004	24	0.076	440	0.076	75	540
CO	0.008	54	0.169	975	0.169	167	1,196
NO _x	0.002	12	0.037	214	0.037	37	262
PM	0.000	0	0.001	7	0.001	1	9
CO ₂	3.599	22,967	71.987	416,155	71.987	71,123	510,246

a. Nationwide impacts are based on AP-42 Emission Guidelines for Industrial Flares as outlined in Table 4-7. As such, these emissions should be considered the minimum level of secondary emissions expected.

b. The REC operational standard (Regulatory Option 3 – REC) combines REC and combustion is assumed to capture 90 percent of flowback gas. 5 percent of the flowback is assumed to be combusted by the combustion device. Therefore, it is estimated 50 Mcf is combusted per completion event. This analysis assumes there are 6,381 developmental oil well completions and recompletions using this control scenario.

c. The REC operational standard (Regulatory Option 3 – Combustion) Assumes 949 Mcf of natural gas is combusted per completion. This analysis assumes 5,781 development oil well completions and recompletions exploratory wells fall into this category.

d. Assumes 949 Mcf of natural gas is combusted per completion. This analysis assumes 988 exploratory wells fall into this category.

Table 8-6. Nationwide Secondary Impacts of Selected Regulatory Options for Projected Year 2025^a

Pollutant	Regulatory Option 3 ^{b,c}				Regulatory Option 4 ^d		Combined Options
	1. Developmental Oil Well - REC		1. Developmental Oil Well - Combustion		2. Exploratory/Delineation Oil Well		
	Emissions per Completion Event (tons)	Nationwide Secondary Emissions (tpy)	Emissions per Completion Event (tons)	Nationwide Secondary Emissions (tpy)	Emissions per Completion Event (tons)	Nationwide Secondary Emissions (tpy)	Nationwide Secondary Emissions (tpy)
THC	0.004	26	0.076	468	0.076	83	576
CO	0.008	57	0.169	1,037	0.169	183	1,2763
NO _x	0.002	13	0.037	227	0.037	40	280
PM	0.000	0	0.001	8	0.001	1	9
CO ₂	3.599	24,407	71.987	442,287	71.987	77,962	544,655

a. Nationwide impacts are based on AP-42 Emission Guidelines for Industrial Flares as outlined in Table 4-7. As such, these emissions should be considered the minimum level of secondary emissions expected.

b. The REC operational standard (Regulatory Options 3 REC) combines REC and combustion is assumed to capture 90 percent of flowback gas. 95 percent of the remaining flowback is assumed to be combusted by the combustion device. Therefore, it is estimated 50 Mcf is combusted per completion event. This analysis assumes there are 6,781 developmental oil well completions and recompletions using this control scenario.

c. Assumes 949 Mcf of natural gas is combusted per completion. This analysis assumes 6,144 development oil well completions and recompletions exploratory wells fall into this category.

d. Assumes 949 Mcf of natural gas is combusted per completion. This analysis assumes 1,083 exploratory wells fall into this category.

9.0 NATIONWIDE IMPACTS FOR FUGITIVE EMISSIONS STANDARDS

9.1 Nationwide Emissions from New Sources

9.1.1 Overview of Approach

Similar to the approach used to calculate emissions from well site and compressor station model plants, nationwide emissions were calculated by using the model plant emissions that were calculated for the oil and natural well sites and compressor stations. These model plant emissions were used for estimating the baseline emissions and emission reductions for the new sources.

9.1.2 Activity Data

Data from oil and natural gas technical documents and inventories were used to estimate the number of new sources for each of the oil and natural gas segments. Information from the DrillingInfo HPDI® database and GHG Inventory were used to estimate the number of new well sites, gathering and boosting stations, and transmission and storage facilities in 2012. A summary of the steps used to estimate the new sources for each of the oil and gas segments is presented in the following sections.

9.1.2.1 Well Sites

The DrillingInfo database provided the information on the number of oil and natural gas wells completed or recompleted in the 2012 in the U.S. The total number of new natural gas well completions, both conventional and fractured was determined to be 8,456. From this number of wells, the EPA subtracted wells that were assumed to be covered by state leak regulations as of the effective date of the revised NSPS. Based on our research, four states have recently enacted leak regulations; Colorado, Ohio, Wyoming and Utah. Below is a brief discussion of these state regulations:

- Colorado: Effective on April 14, 2014, requires well production facilities and natural gas compression station owners/operators to inspect components for leaks using an approved instrument monitoring method (AIMM). This LDAR program began as early as January 1, 2015 with inspection frequency varying based on the amount of fugitive VOC emissions identified (i.e., 0-6 tpy - one-time, 6-12 tpy -annually, 12-50 tpy -quarterly, or >50 tpy -monthly). Monitoring inspections of well production facility and compressor station components must be conducted using Method 21, an infra-red camera, or other Division approved instrument based monitoring devices or methods. In addition, monthly audio, visual, and olfactory inspections must be

conducted to identify leaks. When OGI is used for leak detection, a leak is defined as any detectable emissions that are not associated with normal equipment operation (e.g. pneumatic device actuation)¹¹⁹. For compressor station facilities constructed prior to May 1, 2014, a leak is defined as any concentration of hydrocarbon above 2,000 ppm when Method 21 is used to conduct monitoring inspections. For well sites and compressor stations that were constructed on or after May 1, 2014, a leaks is defined as any concentration of hydrocarbon above 500 ppm when Method 21 is used.

- Ohio: On May 19, 2014 Ohio EPA approved two types of oil and gas well-site production operations (small flares and large flares) and high volume horizontal hydraulic fracturing general permits for facilities that emit less than 1 ton per year of any toxic air contaminant (not including HAP emitting sources that are subject to MACT HH). Operators are required to develop and implement a site-specific LDAR program for ancillary equipment (e.g., vent, compressor, PRD, flange, etc.) that requires monitoring using a FLIR camera or Method 21. Quarterly monitoring is required for the first year and varies after that depending on performance.¹²⁰ Ohio has also proposed a package of general permits that have been designed around a natural gas compressor station that has the potential to leak greater than 10 tons per year of VOC. The general permit requirements include quarterly monitoring of ancillary equipment, including each pump, compressor, pressure relief device, connector, valve, flange, vent, cover, any bypass in the closed vent system, and each storage vessel using either an OGI or an analyzer meeting U.S. EPA Method 21 of 40 CFR Part 60, Appendix A.
- Utah: On June 5, 2014, Utah Department of Environmental Quality approved a “General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery” on June 5, 2014. This GAO requires LDAR for equipment (e.g., valves, pumps, etc.) at least annually, and initial quarterly surveying of sources with projected annual throughput of crude oil and condensate combined that is greater than 25,000 barrels. The monitoring can be performed using Method 21 (leak definition of 500 ppm), a tunable diode laser absorption spectroscopy or an IR camera.¹²¹

¹¹⁹ Colorado regulations available at https://www.colorado.gov/pacific/sites/default/files/5-CCR-1001-9_0.pdf.

¹²⁰ Ohio regulations available at http://www.epa.ohio.gov/Portals/27/oil%20and%20gas/GP12.1_PTIOA20140403final.pdf
<http://epa.ohio.gov/dapc/genpermit/genpermits.aspx#127854016-available-permits>.

¹²¹ Utah regulations are available at <http://www.deq.utah.gov/Permits/GAOs/docs/2014/6June/DAQE-AN149250001-14.pdf>.

- Wyoming: On June 30, 2015, Wyoming Department of environmental Quality issued regulations for existing (as of January 1, 2014) PAD and single-well oil and gas production facilities that are located in the Upper Green River Basin. The rule regulates fugitive emissions from PAD and single-well facilities or sources, and compressor stations with fugitive emissions greater than or equal to 4 tons per year of VOC and requires owner/operators to develop and implement an LDAR protocol by January 1, 2017. Fugitive emissions monitoring can be conducted using a combination of Method 21, OGI, other instrument based technologies, or AVO inspections. However, an LDAR protocol consisting of only AVO inspections does not meet the requirements of the rule - at least one quarterly evaluation must be done using Method 21, OGI, or other instrument based technology. The rule requires quarterly monitoring of control equipment, systems, and devices (e.g. reboiler overhead condensers, storage tanks, vent lines, valves, connectors, etc.).¹²²

9.1.3 Emission Estimates

The nationwide emissions were calculated using the model plant data and the estimated number of new and modified sources for each of the segments. The nationwide emission estimates for the total number of oil and natural gas production well sites, gathering and boosting stations, and transmission and storage facilities incrementally affected by the fugitive emission requirements in the NSPS for are summarized in Table 9-1. The summary includes baseline emissions for each of these segments for projected years 2020 and 2025.

Table 9-1. Nationwide Baseline Emissions for Sources Subject to NSPS Monitoring and Repair Plans in 2020 and 2025

Oil and Gas Segment	Number of Sources Subject to NSPS ^a	Methane Emissions (tpy)	VOC Emissions (tpy)
Projected Year 2020			
Natural Gas Well Sites	16,819	92,425	25,692
Oil Well Sites (GOR < 300)	32,392	39,989	10,726
Oil Well Sites (GOR > 300)	44,367	122,013	33,382
Gathering & Boosting Stations	480	16,868	4,689
Transmission Stations	20	808	22
Storage Stations	25	3,561	99

¹²² Wyoming regulations are available at <http://soswy.state.wy.us/Rules/RULES/9868.pdf>.

Oil and Gas Segment	Number of Sources Subject to NSPS^a	Methane Emissions (tpy)	VOC Emissions (tpy)
Projected Year 2025			
Natural Gas Well Sites	34,487	189,515	52,680
Oil Well Sites (GOR < 300)	66,173	81,693	21,912
Oil Well Sites (GOR > 300)	90,636	249,256	68,196
Gathering & Boosting Stations	960	33,737	9,378
Transmission Stations	40	1,616	45
Storage Stations	50	7,122	197

a. Affected facilities in 2020 include new facilities in 2016 through 2020 which are assumed to still be operating in 2020. Affected facilities in 2025 includes new affected facilities in 2016 through 2025 which are assumed to still be operating in 2025.

According to our analysis, 20.87 percent of the total number of new natural gas well completions, both conventional and fractured, were covered by leak regulations in these four states. Therefore the number of new natural gas wells covered by federal regulations was estimated to be 6,691. Assuming an average of two natural gas wells per well site, the number of new well sites in 2012 was estimated to be 3,346. Projections from the NEMS data were used to estimate the total number of new natural gas completions, both conventional and hydraulically fractured in the years 2020 and 2025. The percentage of wells covered by state leak regulations, and the 2 natural gas wells per well site assumptions were applied to these totals to estimate the number of new natural gas production well sites. Our projected activity for year 2020 was developed to reflect the total number of affected facilities in 2020 which is the accumulation of newly affected facilities from 2016 through and including 2020. Likewise, our projected year 2025 reflects total accumulated newly affected facilities from 2016 through and including 2025. These activity estimates assume all newly affected facilities continue to be operating in the projected years. The number of natural gas well sites was estimated to be 16,819 well sites in 2020 and 34,487 in 2025. These estimated well site values were used to calculate the national fugitive emissions from natural gas well sites in 2012, 2020 and 2025. Low production wells were assumed to be 30 percent of the total natural gas well sites based on a sensitivity analysis of the well site data.

For oil wells, the same approach used for natural gas wells was used to estimate the number of new oil wells in the U.S. The number of new oil well completions in 2012, both conventional and hydraulically fractured, was determined to be 35,404. It was assumed that 8.81 percent of these oil wells are covered by state regulations in 2012 based on information in the HPDI database, which includes: Colorado, Ohio, Wyoming and Utah. Therefore 32,285 new oil wells were not covered by state leak regulations in 2012. Assuming an average of two oil production wells per well site, the number of new oil production well sites

was determined to be 16,142 in 2012. Projections from the NEMS data were used to estimate the total number of new oil well completions in the years 2020 and 2025. The percentage of wells covered by State leak regulations, and the two oil wells per well site assumptions was applied to these totals to estimate the number of new oil well production sites. Because the requirements have impacts annually, our projected activity for years 2020 and 2025 were developed to reflect the facilities newly affected by the rule from 2016 through 2020 and 2016 through 2025, respectively, and assumed to still be in operation in the analysis years. The number of oil well sites were estimated to be 76,759 well sites in 2020 and 156,809 in 2025. These estimated well site values were used to calculate the national fugitive emissions from natural gas well sites in 2012, 2020 and 2025. Low production wells were assumed to be 43 percent of the total oil well sites based on a sensitivity analysis of the well site data. Oil well sites with a gas-to-oil ratio of greater than 300 were assumed to account for 57.8 percent of the total oil well sites based on data from the HPDI database as summarized in Table 9-1.

9.1.3.1 Gathering and Boosting Stations

The number of new gathering and boosting stations was estimated using the current number of gathering compressors estimated in the GHG Inventory. The total number of small and large gathering compressors was listed as 36,066 in the inventory. The EPA/GRI document does not include a separate list of individual compressors for gathering and boosting stations, but it does list the average number of compressors in the gas production section. It was assumed that this average of 4.5 compressors for gas production facilities is applicable to gathering and boosting stations. Therefore, using the total number of compressors in the GHG Inventory, the number of gathering and boosting stations was estimated to be 8,015. To estimate the number of new gathering and boosting stations, the EPA used an annual growth rate of 1.2 percent, which is based on the gas well CAGR for new gas wells divided by the average wells per well site. This provided an estimate of 96 new gathering and boosting stations each year that would be affected sources under the proposed NSPS in each of the years 2012 through 2025. Because the requirements have impacts annually, our projected activity for year 2025 was developed to reflect the impacts of the rule from 2020 through 2025 as summarized in Table 9-1. This approach was used to support the regulatory impacts assessment process to reflect rule impacts from the effective date through 2025.

9.1.3.2 Transmission and Storage Facilities

The number of new transmission and storage facilities was estimated by reviewing the annual number of facilities from the year 1990 to 2013 estimated in the GHG Inventory published in 2015 and determining

the rate of change in the number of these facilities over this period. The average change for the last 10 years was reviewed and the annual number of new transmission stations was determined to be 4 and the annual number of storage facilities was determined to be 5. The values were used to estimate the number of affected sources under the NSPS in each of the years 2012 through 2025. Because the requirements have impacts annually, our projected activity for year 2025 was developed to reflect the impacts of the rule from 2020 through 2025 as summarized in Table 9-1. This approach was used to support the regulatory impacts assessment process to reflect rule impacts from the effective date through 2025.

9.1.4 Nationwide Impacts of Regulatory Options

This section provides an analysis of the primary environmental impacts (i.e., emission reductions), cost impacts and secondary environmental impacts related to the regulatory options which were selected as a viable options for reducing fugitive emissions from fugitive emissions components located at production well sites and compressor stations.

9.1.4.1 Primary Environmental Impacts of Regulatory Options

Based on the discussion above, the EPA reconsidered Regulatory Options 1 and 2 for well sites and Regulatory Options 1, 2 and 3 for compressor stations. A summary of the options are provided below;

- Regulatory Option 1. Require the implementation of a fugitive emissions monitoring and repair program which includes annual monitoring of fugitive emissions components using OGI.
- Regulatory Option 2. Require the implementation of a fugitive emissions monitoring and repair program which includes semiannual monitoring of fugitive emissions and components using OGI.
- Regulatory Option 3. Require the implementation of a fugitive emissions monitoring and repair program which includes quarterly monitoring of fugitive emissions components using OGI.

The number of oil and natural gas well sites, gathering and boosting stations, transmission stations, and storage facilities that would be subject to the regulatory options listed above were estimated using data from the HPDI database. In 2020, which include all new and modified sources since 2016, it was estimated that there would be 76,759 oil well sites, 16,819 gas well sites, 480 gathering and boosting stations, 20 transmission stations, and 25 storage facilities subject to these options. In 2025, which include all new and modified sources since 2016, it was estimated that there would be 156,809 oil well sites, 34,487 gas well sites, 960 gathering and boosting stations, 40 transmission stations, and 50 storage facilities subject to these options.

It was estimated that OGI monitoring and repair can achieve an overall 40 percent VOC and methane reduction for annual monitoring, 60 percent VOC and methane reduction for semiannual monitoring, and 80 percent VOC and methane reduction for quarterly monitoring over the life span of the facility. These percent reduction values were estimated based on information from the EPA white paper and an analysis by the Colorado Air Quality Control Commission as described previously. Nationwide emission reductions were estimated by applying this 40, 60 and 80 percent VOC and methane reduction to the uncontrolled baseline emissions for well sites and compressor stations. In considering the three frequency options, the EPA considered the implementation issues with respect to the monitoring and repair plan and the EPA determined that, based on input from industry and regulatory agencies, that the program frequency should be consistent across the segments in the oil and natural gas source category. Therefore, nationwide impacts were estimated for these options as presented in Tables 9-2, 9-3 and 9-4.

9.1.4.2 Cost Impacts

OGI Monitoring and Repair Plans (Options 1, 2 and 3)

Regulatory Option 1 include annual monitoring of fugitive emissions components using OGI and repair of fugitive emissions components that are found to be leaking during the survey. The annual costs for these surveys (as summarized in Table 9-2) include the costs for having a contractor perform the annual OGI survey, activities planning, repair costs, resurvey of repaired components using a Method 21 device, preparation and submittal of an annual report and the amortization of the capital costs over 8 years at 7 percent interest. The potential natural gas saved from the implementation of an annual OGI monitoring and repair program at well sites was calculated to be 127 thousand standard cubic feet per year (Mscf/yr) for a natural gas production well site, 64 Mscf/yr for an oil well site with a GOR > 300, and 29 Mscf/yr for an oil production well site with a GOR < 300. For the compressor stations, the potential natural gas saved was calculated to be 815 Mscf/yr for gathering and boosting stations, 836 Mscf/yr for transmission stations, and 2,950 Mscf/yr for storage facilities.¹²³

Operators in the gathering and boosting and transmission and storage parts of the industry typically do not own the natural gas they transport; rather, the operators receive payment for the transportation service they provide. As a result, the unit-level cost and emission reduction analyses supporting BSER decisions in the preamble (and is presented in Volume 1 of the TSD) do not include estimates of revenue

¹²³ Natural gas savings calculated using the CH₄ reductions and assuming a methane to natural gas volume ration of 82.9% for upstream facilities (well sites, gathering & boosting) and a methane to natural gas volume ratio of 92.8% for downstream facilities (transmission, storage).

from natural gas recovery as offsets to compliance costs. From a social perspective, however, the increased financial returns from natural gas recovery accrues to entities somewhere along the natural gas supply chain and should be accounted for in the national impacts analysis. An economic argument can be made that, in the long run, no single entity is going to bear the entire burden of the compliance costs or fully receive the financial gain of the additional revenues associated with natural gas recovery. The change in economic surplus resulting from natural gas recovery is going to be spread out amongst different agents via price mechanisms. Therefore, the most simple and transparent option for allocating these revenues would be to keep the compliance costs and associated revenues together in a given source category and not add assumptions regarding the allocation of these revenues across agents. This is the approach followed in Volume 2 of the TSD, as well as in the RIA. Table 9-2 also summarizes the nationwide cost impacts for the projected years 2020 and 2025 for implementation of regulatory Option 1.

Regulatory Option 2 include semiannual monitoring of fugitive emissions components using OGI and repair of fugitive emissions components that are found to be leaking during the survey. The annual costs for these surveys (as summarized in Table 9-3) include the costs for having a contractor perform the semiannual OGI survey, activities planning, repair costs, preparation and submittal of an annual report and the amortization of the capital costs over 8 years at 7 percent interest. The potential natural gas savings from the implementation of a semiannual OGI monitoring and repair program were calculated to be 191 Mscf/yr for a natural gas production well site, 96 Mscf/yr for an oil production well site with a GOR > 300, and 43 Mscf/yr for an oil production well site with a GOR < 300. For the compressor stations, the potential natural gas savings were calculated to be 1,222 Mscf/yr for gathering and boosting stations, 1,255 Mscf/yr for transmission stations, and 4,424 Mscf/yr for storage facilities.¹²⁴ Table 9-3 summarizes the nationwide cost impacts for the projected years 2020 and 2025 for implementation of regulatory Option 2.

Regulatory Option 3 for well sites and compressor stations include quarterly monitoring of fugitive emissions components using OGI and repair of fugitive emissions components that are found to be leaking during the survey. The annual costs for these surveys (as summarized in Table 9-4) include the costs for having a contractor perform the quarterly OGI survey, activities planning, repair costs, preparation and submittal of an annual report and the amortization of the capital costs over 8 years at 7 percent interest. The potential natural gas saved from the implementation of a quarterly OGI monitoring and repair

¹²⁴ Ibid.

program at well sites was calculated to be 255 Mscf/yr for a natural gas production well site, 127 Mscf/yr for an oil well site with a GOR > 300, and 57 Mscf/yr for an oil production well site with a GOR < 300. The potential natural gas savings at compressor stations were calculated to be 1,629 Mscf/yr for gathering and boosting stations, 1,673 Mscf/yr for transmission stations, and 5,899 Mscf/yr for storage facilities.¹²⁵ Table 9-4 summarizes the nationwide cost impacts for the projected years 2020 and 2025 for implementation of regulatory Option 3.

9.1.4.3 Low Producing Natural Gas and Oil Wells

For the proposed rule, the EPA evaluated an alternative nationwide impact scenario that accounts for well sites that produce relatively little crude oil and/or natural gas. The EPA had proposed that low producing wells not be subject to fugitive emissions monitoring provisions. While there were several criteria for defining a low-producing well, the EPA believed the definition of a "stripper well" in Internal Revenue Services (IRS) regulations, was consistent with the type of well which would be considered low-producing under that scenario. Under the IRS regulations, a stripper well property "means, with respect to any calendar year, any property with respect to which the amount determined by dividing—(i) the average daily production of domestic crude oil and domestic natural gas from producing wells on such property for such calendar year, by (ii) the number of such wells, is 15 barrel equivalents or less".¹²⁶ This proposal was based on our belief at the time that low production wells have inherently low emissions from well completions and that many are owned and operated by small businesses. The EPA was concerned about the burden of the well completion requirement on small businesses, in particular if there is little emission reduction to be achieved.

However, based on information provided in the comments for the proposed rule, the EPA determined that fugitive emissions from low production wells may be comparable to fugitive emissions from other production wells. The low production well sites have the same type of equipment (e.g., separators, storage vessels) and components (e.g., valves, flanges, connectors) as production well sites with production greater than 15 boe per day. This indicates that the component counts for low production well sites are similar to that of non-low production well sites, and hence the potential fugitive emissions from both types of well sites are comparable. The comments on the proposed rule stated that many of these well sites are developed for leasing purposes and are typically unmanned and not visited as often as

¹²⁵ Ibid.

¹²⁶ 26 U.S.C. 613A(c)(6)(E).

other well sites. This may potentially allow fugitive emissions to go unnoticed longer. No data were provided in the comments on the proposed rule that shows low production well sites have lower GHG (principally as methane) or VOC emissions than normal production well sites. In fact, the data that were provided indicated that the potential emissions from these well sites could be as significant as the emissions from non-low production well sites since the type of equipment and the well pressures are more than likely the same. In addition, discussions with the industry indicated that well site fugitive emissions are not based on production, but rather on the number of equipment and components. Therefore, the EPA believes that the emissions from low production and non-low production well sites are likely comparable and are included as affected sources for fugitive emissions.

Table 9-2. Nationwide Emission and Cost Analysis for Regulatory Option 1 – Annual OGI Monitoring and Repair

Fugitive Emission Component Location	Number of Sources Subject to NSPS	Annual Cost Per Facility (\$)	Annual Cost Per Facility (\$)	Nationwide Emission Reductions (tpy)		Total Nationwide Costs (million \$/year)	
		without savings	with savings	Methane	VOC	without savings	with savings
Projected Year 2020							
Gas Well Sites	16,819	\$1,318	\$809	36,970	10,277	\$22.2	\$13.6
Oil Well Sites (GOR < 300)	32,392	\$1,318	\$1,204	15,996	4,290	\$42.7	\$38.9
Oil Well Sites (GOR > 300)	44,367	\$1,318	\$1,063	48,805	13,353	\$58.5	\$47.2
Well Sites Total	93,578	NA	NA	101,771	27,920	\$123.4	\$99.7
Gathering & Boosting	480	\$7,777	\$4,518	6,747	1,876	\$3.7	\$2.2
Transmission	20	\$10,117	\$6,372	323	9	\$0.2	\$0.1
Storage	25	\$13,798	\$590	1,424	39	\$0.3	\$0.01
Compressor Stations Total	525	NA	NA	8,494	1,924	\$4.2	\$2.3
Projected Year 2025							
Gas Well Sites	34,487	\$1,318	\$809	75,806	21,072	\$45.5	\$27.9
Oil Well Sites (GOR < 300)	66,173	\$1,318	\$1,204	32,677	8,765	\$87.2	\$79.7
Oil Well Sites (GOR > 300)	90,636	\$1,318	\$1,063	99,702	27,278	\$119.5	\$96.4
Well Sites Total	191,296	NA	NA	208,185	57,115	\$252.2	\$204
Gathering & Boosting	960	\$7,777	\$4,518	13,495	3,751	\$7.5	\$4.3
Transmission	40	\$10,117	\$6,372	646	18	\$0.4	\$0.3
Storage	50	\$13,798	\$590	2,849	79	\$0.7	\$0.02
Compressor Stations Total	1,050	NA	NA	16,990	3,848	\$8.6	\$4.6

Table 9-3. Nationwide Emission and Cost Analysis for Regulatory Option 2 – Semiannual OGI Monitoring and Repair

Fugitive Emission Component Location	Number of Sources Subject to NSPS	Annual Cost Per Facility (\$)	Annual Cost Per Facility (\$)	Nationwide Emission Reductions (tpy)		Total Nationwide Costs (million \$/year)	
		without savings	with savings	Methane	VOC	without savings	with savings
Projected Year 2020							
Gas Well Sites	16,819	\$2,285	\$1,521	55,455	15,415	\$38.4	\$25.6
Oil Well Sites (GOR < 300)	32,392	\$2,285	\$2,114	23,993	6,436	\$74.0	\$68.5
Oil Well Sites (GOR > 300)	44,367	\$2,285	\$1,903	73,208	20,029	\$101.4	\$84.4
Well Sites Total	93,578	NA	NA	152,656	41,880	\$213.8	\$178.5
Gathering & Boosting	480	\$13,534	\$8,646	10,121	2,813	\$6.5	\$4.2
Transmission	20	\$15,868	\$10,250	485	13	\$0.3	\$0.2
Storage	25	\$23,230	\$3,418	2,137	59	\$0.6	\$0.1
Compressor Stations Total	525	NA	NA	12,743	2,885	\$7.4	\$4.5
Projected Year 2025							
Gas Well Sites	34,487	\$2,285	\$1,521	113,709	31,608	\$78.8	\$52.5
Oil Well Sites (GOR < 300)	66,173	\$2,285	\$2,114	49,016	13,147	\$151.2	\$139.9
Oil Well Sites (GOR > 300)	90,636	\$2,285	\$1,903	149,554	40,917	\$207.1	\$172.5
Well Sites Total	191,296	NA	NA	312,279	85,672	\$437.1	\$364.9
Gathering & Boosting	960	\$13,534	\$8,646	20,242	5,627	\$13.0	\$8.3
Transmission	40	\$15,868	\$10,250	969	27	\$0.6	\$0.4
Storage	50	\$23,230	\$3,418	4,273	118	\$1.2	\$0.2
Compressor Stations Total	1,050	NA	NA	25,484	5,772	\$14.8	\$8.9

Table 9-4. Nationwide Emission and Cost Analysis for Regulatory Option 3 – Quarterly OGI Monitoring and Repair

Fugitive Emission Component Location	Number of Sources Subject to NSPS	Annual Cost Per Facility (\$)		Nationwide Emission Reductions (tpy)		Total Nationwide Costs (million \$/year)	
		without savings	with savings	Methane	VOC	without savings	with savings
Projected Year 2020							
Gas Well Sites	16,819	\$4,220	\$3,201	73,940	20,553	\$70.9	\$53.8
Oil Well Sites (GOR < 300)	32,392	\$4,220	\$3,991	31,991	8,581	\$136.7	\$129.3
Oil Well Sites (GOR > 300)	44,367	\$4,220	\$3,710	97,610	26,706	\$187.2	\$164.6
Well Sites Total	93,578	NA	NA	203,541	55,840	\$394.8	\$347.7
Gathering & Boosting	480	\$25,049	\$18,532	13,495	3,751	\$12.0	\$8.9
Transmission	20	\$27,369	\$19,879	646	18	\$0.5	\$0.4
Storage	25	\$42,093	\$15,678	2,849	79	\$1.1	\$0.4
Compressor Stations Total	525	NA	NA	16,990	3,848	\$13.6	\$9.7
Projected Year 2025							
Gas Well Sites	34,487	\$4,220	\$3,201	151,612	42,144	\$145.5	\$110.4
Oil Well Sites (GOR < 300)	66,173	\$4,220	\$3,991	65,354	17,530	\$279.2	\$264.0
Oil Well Sites (GOR > 300)	90,636	\$4,220	\$3,710	199,405	54,557	\$382.4	\$336.2
Well Sites Total	191,296	NA	NA	416,371	114,231	\$807.1	\$710.6
Gathering & Boosting	960	\$25,049	\$18,532	26,989	7,502	\$24.0	\$17.8
Transmission	40	\$27,369	\$19,879	1,293	36	\$1.1	\$0.8
Storage	50	\$42,093	\$15,678	5,698	158	\$2.1	\$0.8
Compressor Stations Total	1,050	NA	NA	33,980	7,696	\$27.2	\$19.4

10.0 NATIONWIDE IMPACTS FOR PNEUMATIC CONTROLLERS

10.1 Nationwide Emissions from New Sources

10.1.1 Approach

Nationwide emissions from newly installed natural gas pneumatic devices for a typical year were calculated by estimating the number of pneumatic devices installed in a typical year and multiplying by the estimated annual emissions per device listed in Table 5-2. The number of new pneumatic devices installed for a typical year was determined using the methodologies described in section 10.1.2 of this chapter.

10.1.2 Population of Controllers Installed Annually

The number of pneumatic controllers installed in the transmission and storage segment was approximated using the Inventory of U.S. GHG Emissions and Sinks: 1990-2012. The number of new devices installed in a given year was estimated by subtracting the prior year (e.g., 2011) from the given years total (e.g., 2012). This difference was assumed to be the number of new devices installed in the latter year (e.g., Number of new devices installed during 2012 equals pneumatics in 2012 minus pneumatics in 2011). A 10-year average was calculated based on the number of new controllers installed in 2003 through 2012 in order to determine the average number of new devices installed in a typical year. An average was taken of all years. Where the year change was negative, the average calculation treated it as zero.

The number of facilities estimated to be subject to regulation was undeterminable due to the magnitude of new sources estimated and the lack of sufficient data that could indicate the number of controllers that would be installed in states that may have regulations requiring low-bleed controllers, such as in Wyoming and Colorado. Therefore, the EPA considered all facilities to be unregulated for this analysis.

Once the population counts for the number of pneumatics in each segment were established, this population count was further refined to account for the number of intermittent controllers that would be installed versus a bleed controller. This estimate of the percent of intermittent and bleed controllers was based on data from the GRI study, where 32 percent of the pneumatic controllers are bleed devices in the production segment, and 32 percent of the pneumatic controllers are bleed devices in the transmission and

storage segment.¹²⁷ The distinction between the number of high-bleed and low-bleed devices was not estimated because this analysis assumes it is not possible to predict or ensure where low bleeds will be used in the future. Table 10-1 summarizes the estimated number of new devices installed per year.

Table 10-1. Estimated Number of Pneumatic Controllers Installed in a Typical Year in the Natural Gas Transmission and Storage Segment

Number of New Controllers Estimated for a Typical Year ^{a, b}		
Intermittent	Bleed-Devices	Total
256	120	376

a. National averages of population counts from the Inventory were refined to include the difference in intermittent and bleed devices based on raw data found in the GRI/EPA study. This is based on the assumption that 32 percent of the pneumatic controllers are bleed devices in the transmission and storage segment.

b. The number of pneumatics controllers estimated for the transmission and storage segment was approximated from comparing a 10 year average of new controllers installed in 2003 through 2012 in order to establish an average number of pneumatics being installed in this industry segment in a typical year. This analysis was performed using the Inventory of U.S. GHG Emissions and Sinks: 1990-2012.

10.1.3 Nationwide Emission Estimates

Nationwide baseline emission estimates for pneumatic devices for new sources in a typical year are summarized in Table 10-2. This analysis assumed for the nationwide emission estimate that all bleed-devices have the high-bleed emission rates estimated in Table W-3 of the GHG Reporting Rule, Subpart W since it cannot be predicted which sources would install a low bleed versus a high bleed controller.

Table 10-2. Nationwide Baseline Emissions from Representative Pneumatic Controller Installed in a Typical Year in Natural Gas Transmission and Storage Segment^{a, b}

Baseline Emissions from Representative New Continuous Bleed Controller (tpy)		Number of New Continuous Bleed Controllers Expected Per Year	Nationwide Baseline Emissions from New Continuous Bleed Controller (tpy)	
Methane	VOC		Methane	VOC
3.013	0.083	120	362	10

a. Baseline emissions were based on the bleed rates for a high-bleed controllers.

b. To estimate VOC emissions, the weight ratio of 0.0277 lbs VOC per pound methane was used.

10.2 Nationwide Cost Impacts of Regulatory Options

Operators in the gathering and boosting and transmission and storage parts of the industry typically do not own the natural gas they transport; rather, the operators receive payment for the transportation service they provide. As a result, the unit-level cost and emission reduction analyses supporting BSER decisions in the preamble (and is presented in Volume 1 of the TSD) do not include estimates of revenue from natural gas recovery as offsets to compliance costs. From a social perspective,

¹²⁷ See footnote 57.

however, the increased financial returns from natural gas recovery accrues to entities somewhere along the natural gas supply chain and should be accounted for in the national impacts analysis. An economic argument can be made that, in the long run, no single entity is going to bear the entire burden of the compliance costs or fully receive the financial gain of the additional revenues associated with natural gas recovery. The change in economic surplus resulting from natural gas recovery is going to be spread out amongst different agents via price mechanisms. Therefore, the most simple and transparent option for allocating these revenues would be to keep the compliance costs and associated revenues together in a given source category and not add assumptions regarding the allocation of these revenues across agents. This is the approach followed in Volume 2 of the TSD, as well as in the RIA.

Table 10-3 summarizes the nationwide emission reductions and nationwide costs impacts of the selected regulatory option for the natural gas transmission and storage segment. It is estimated to affect 96 new transmission and storage pneumatic controllers per year and 480 new affected sources through 2020 and 960 affected sources through 2025. The nationwide capital cost for projected year 2020 is estimated to be \$109,073 and annual costs of \$11,976 without considering value of gas saved. With consideration of gas savings from recovered gas, the annual cost for projected year 2020 is a net savings of \$270,264. The nationwide capital cost for projected year 2025 is estimated to be \$218,146 and annual costs of \$23,951 without considering savings from gas saved. With consideration of gas savings from recovered gas, the annual cost for projected year 2025 is a net savings of \$540,529.

Table 10-3. Nationwide Cost and Emission Reduction Impacts for Pneumatic Controllers for Transmission and Storage for the Projected Years 2020 and 2025

Number of Affected Facilities ^a	Capital Cost Per Controller ^b	Annual Costs		Nationwide Emission Reductions				Total Nationwide Costs (\$/year)		
		w/o savings	w/savings	(tpy)			(metric tonnes)	Capital Cost	Annualized Cost	
		(2012)	(\$/year)	Methane	VOC	HAP	CO2e		w/o savings	w/savings
Projected Year 2020										
480	\$227	\$25	(\$563)	1,338	37	1	30,335	\$109,073	\$11,976	(\$270,264)
Projected Year 2025										
960	\$227	\$25	(\$563)	2,675	74	2	60,671	\$218,146	\$23,951	(\$540,529)

a. The number of sources subject to NSPS for the natural gas transmission and storage segment represent the number of new controllers expected per year (120) reduced by 20 percent. This is consistent with the assumption that 80 percent of high bleed controllers can be replaced with a low bleed device. It is assumed all new sources would be installed as a high bleed for these segments.

b. The capital cost is equal to the incremental cost of a low bleed device versus a new high bleed device.

c. Based on the global potential warming of methane equal to 25.

Note: Negative numbers reflect a net savings.

11.0 NATIONWIDE IMPACTS FOR PNEUMATIC PUMPS

11.1 Nationwide Emissions from New Sources

11.1.1 Approach

Nationwide emissions from newly installed natural gas pneumatic pumps for a typical year were calculated by estimating the count of pneumatic pumps installed in a typical year and multiplying by the estimated annual emissions per device listed in Table 6-2. The count of new pneumatic pumps installed for a typical year was determined for each natural gas production and natural gas processing. The methodologies that determined the estimated count of new pneumatic pumps installed in a typical year is provided below.

11.1.2 Population of Pneumatic Pumps Installed Annually

For the natural gas production segment the count of new pneumatic pumps installed in a typical year was estimated by reviewing the annual count of pneumatic pumps from the year 1990 to 2012 reported in the GHG Inventory for the natural gas and oil production facilities and determining the rate of change in the count of pneumatic pumps in each inventory over this period. For all the years, the annual counts of new pneumatic pumps installed between two years were not consistent. The average change for the entire period was estimated to be 877 for natural gas facilities and (-161) for oil facilities. Additionally, the average change over the last 10 years was estimated to be 1,480 for natural gas facilities and 803 for oil facilities. Because of the fluctuation in the count of new pneumatic pumps from the years 1990 to 2012, it was assumed that the 10-year average change represented a better estimate of the current growth of pneumatic pumps. For proposal the EPA calculated the average change excluding years where there was a negative change in the number of pneumatic pumps IPs. Based on comments received, the EPA changed the methodology to include the years where there was a negative change as zero in the averaging calculation. Based on this methodology, the counts of new pneumatic pumps that would be affected sources under the proposed NSPS for a typical year was estimated to be 1,184 for natural gas facilities and 241 for oil facilities.

To forecast the count of pneumatic pumps replaced in a *typical* year, age and count of gas and oil wells for 2012 were extracted from DI Desktop[®]. The age of the pneumatic pump was assumed to be the age of the well. The average lifetime of a pneumatic pump was assumed to be 10 years. Therefore, a portion of CIPs that reached 10 years in a particular year were assumed to be replaced that year. For a typical year for this analysis, the replacement count for pneumatic pumps was estimated to be 340

diaphragm pumps and 340 piston pumps for gas wells with the same replacement pump counts for oil wells.

The GHG Inventory¹²⁸ does not estimate any emissions from pneumatic pumps for the natural gas processing, natural gas transmission and storage segments. Pneumatic pump data are not reported in GHGRP for these segments. For this analysis, the EPA assumed that pneumatic pumps are not used in these segments.

Once the population counts of pneumatic pumps in each segment were established, the count of pneumatic pumps was split into diaphragm and piston. Similar to the assumption used in the EPA/GRI Report,¹²⁹ for new and replaced pumps for each segment the EPA assumed 50 percent of the pumps to be diaphragm and 50 percent of the pumps to be piston pumps. Table 11-1 below summarizes the estimated count of new pumps installed per year.

Table 11-1. Estimated Count of Pneumatic Pumps Installed in a Typical Year

Segment/Pump Type	Number of New Pumps
Production/Diaphragm	1,052
Production/Piston	1,052
Processing/Diaphragm and Piston	0
Transmission/Diaphragm and Piston	0
Storage/Diaphragm and Piston	0

11.1.3 Nationwide Emission Estimates

Nationwide baseline emission estimates for pneumatic pumps for new sources in a typical year are summarized in Table 11-2 by industry segment and pump type.

¹²⁸ See footnote 81.

¹²⁹ See footnote 82.

Table 11-2. Nationwide Baseline Emissions from Representative Pneumatic Pumps Installed in a Typical Year for the Oil and Natural Gas Industry

Segment/Pump Type	Number of New Pumps ^a	Emission Factor (tpy) ^b		Nationwide Emissions (tpy)	
		Methane	VOC	Methane	VOC
Production/Diaphragm	1,052	3.46	0.96	3,641	1,012
Production/Piston	1,052	0.38	0.11	400	111
Processing/Diaphragm	0	3.46	0.96	0	0
Processing/Piston	0	0.38	0.11	0	0
Totals				4,040	1,123
Total Production				4,040	1,123
Total Processing				0	0
Total Transmission				0	0
Total Storage				0	0

a. From Table 7-3.

b. From Table 7-2.

11.2 Nationwide Emission Reductions and Cost Impacts of Selected Regulatory Options

The EPA calculated the nationwide impacts of the selected options by considering the estimated affected population for each of the target years, the estimated emission reductions per pneumatic pump controlled by the regulatory option and the annualized cost associated with that control option for that pump in that segment.

For Option 1, based on the activity analysis presented above, the EPA estimated there will be no new pneumatic pumps installed in the natural gas processing segment in either of the projected years 2020 or 2025. Therefore, there will be zero nationwide emission reductions and costs associated with Option 1.

For Option 3 for the final rule, the EPA estimated that there will be 1,052 new, modified, or reconstructed diaphragm pumps installed in a typical year. As noted above, due to inherently low emissions, piston pumps were removed from coverage under the final rule. In addition, for the final rule, the EPA included a provision that allowed for an exemption from control where it is determined to be technically infeasible to connect the pump to an existing control device or process at a non-greenfield site or where the a pump is limited use. The EPA has no data that provides information on the number of pumps located at sites where a control device or process is available. Further, the EPA have no data that indicates how often conditions with respect to the pump and/or the control device would be such that it would be technically infeasible to connect the pump to an existing control device or process or where a pump is limited use. In order to estimate impacts that account for these circumstances that would remove

control requirements for the pumps under the NSPS, the EPA has estimated that 75 percent of the new pumps will be able to be connect to an existing control device or process. Based on this estimate, 789 pumps in a typical year would be subject to control requirements under the rule.

For nationwide impacts, the EPA estimated that a total of 3,946 new or replaced diaphragm pumps will be installed in the production segment from 2016 through and including the projected year 2020, assumed to still be in operation in 2020. For the projected year 2025, the EPA determined the affected population as those affected facilities from the years 2016 through and including 2025, assumed to still be in operation in 2025. Therefore, the EPA estimated that 7,892 new diaphragm pumps will be installed in the production segment by 2025. Table 12-3 summarizes the estimated number of pumps that would be subject to the final rule provisions for the projected years 2020 and 2025.

Table 11-3. Estimated Count of Pneumatic Pumps Installed Subject to NSPS for 2020 and 2025

Segment/Pump Type	Estimated Number of New Pumps			
	Pumps Per Year ^a	Controlled Per Year Under NSPS	Controlled Under NSPS 2020	Controlled Under NSPS 2025
Production/Diaphragm	1,052	789	3,946	7,892
Production/Piston	1,052	0	0	0
Processing/Diaphragm and Piston	0	0	0	0

a. This number includes all newly installed, modified, and reconstructed pumps.

Based on these activity numbers, the nationwide emission reductions in 2020 are estimated to be 12,970 tons per year of methane and 3,605 tons per year of VOC from diaphragm pumps. The total nationwide emission reductions, for the projected year 2025, are estimated to be 25,940 tons per year of methane and 7,210 tons per year of VOC from diaphragm pumps.

The nationwide costs are based only on the Option 3 costs related to routing pump emissions to an existing combustion device or a VRU. The EPA estimated that the annualized cost for routing pump emissions either to a combustion device or a VRU would be \$774. Based on the estimated affected population of 3,946 pneumatic pumps in 2020, the EPA estimated the nationwide cost to be approximately \$3.1 million in 2020. The nationwide costs are estimated to be approximately \$6.1 million in 2025. Table 11-4 summarizes the nationwide emission reduction and cost impacts for projected years 2020 and 2025.

Secondary emissions impacts for Option 3 would include emissions resulting from the combustion of the recovered gas. Table 11-5 summarizes the nationwide secondary emissions for the projected year 2020 and 2025 for Option 3.

Table 11-4. Nationwide Impacts for Gas-Driven Diaphragm Pumps for Projected Years 2020 and 2025

Segment/ Affected Facility	Number of Pumps Subject to NSPS ^a	Annualized Cost ^b	Nationwide Emission Reductions ^c				Nationwide Costs
			(tpy)			(metric (tonnes) ^d	
		(\$)	Methane	VOC	HAP	CO ₂ e	(million \$)
Projected Year 2020							
Natural Gas Processing	0	\$10,051 - \$72,394	0	0	0	0	\$0
Production	3,946	\$774	12,970	3,605	136	294,149	\$3.1
Projected Year 2025							
Natural Gas Processing	0	\$10,051 - \$72,394	0	0	0	0	\$0
Production	7,892	\$774	25,940	7,210	272	588,299	\$6.1

a. From Table 7-19.

b. From Table 7-18.

c. Based on 95 percent control.

d. Assumes 0.90718474 metric tonnes per short ton and global warming potential of methane = 25.

Table 11-5. Nationwide Secondary Impacts from Pneumatic Pumps Routed to a Combustion Device for Projected Years 2020 and 2025

Segment	Secondary Impacts (tpy)				
	THC ^a	CO ^b	CO ₂ ^c	NO _x ^d	PM ^e
Projected Year 2020					
Production	60	133	56,699	292	1
Projected Year 2025					
Production	120	266	113,397	58	0

a. Total hydrocarbons - based on combustion of natural gas stream and AP-42 Total Hydrocarbons emission factors for industrial flares.

b. Carbon monoxide - based on combustion of natural gas stream and AP-42 Carbon Monoxide emission factors for industrial flares.

c. Carbon Dioxide - based on combustion of natural gas stream and 40 CFR Part 98, subpart Y, Equation Y-2.

d. Nitrous Oxides - based on combustion of natural gas stream and AP-42 Nitrogen Oxides emission factors for industrial flares.

e. Particulate Matter - based on combustion of natural gas stream and AP-42 Particulate Matter emission factors for industrial flares. Assumes a "lightly smoking" flare.

12.0 NATIONWIDE IMPACTS FOR COMPRESSORS

12.1 Nationwide Emissions from New Sources

12.1.1 Overview of Approach

The number of new affected facilities in the oil and natural gas source category was estimated using data from the GHG Inventory.¹³⁰ The nationwide emissions estimates for new sources were then determined by multiplying the number of new sources for each oil and natural gas segment by the expected emissions per compressor based on the emission factor data presented in Table 7-3. A summary of the number of new, modified, and reconstructed reciprocating and centrifugal compressors for transmission and storage segment is presented in Table 7-4.

12.1.2 Nationwide Activity Data for Compressors in Transmission and Storage

The number of reciprocating compressors and wet seal centrifugal compressors installed in the transmission and storage segment was estimated using the GHG Inventory. The number of new reciprocating compressors, wet seal centrifugal compressors, and dry seal centrifugal compressors installed in a given year was estimated by subtracting the prior year (e.g., 2011) from the given year's (e.g., 2012) total as represented in the Inventory. This difference was assumed to be the number of new compressors installed in the latter year (e.g., number of new compressors installed during 2012 equals the compressors reported in 2012 minus the compressors reported in 2011). A 10-year average was calculated based on the number of new compressors installed in 2003 through 2012 in order to determine the average number of new compressors installed in a typical year. Where the data indicated a decrease in new compressors, the average calculation counted those years as zero. An average was taken of all years and rounded to the nearest whole number. The results of this analysis are shown in Table 12-1.

Table 12-1. Approximate Number of New Compressors in the Transmission and Storage Segment in a Typical Year^a

Compressor Location	Number of New Reciprocating Compressors	Number of New Centrifugal Compressors	
		Wet Seal	Dry Seal
Transmission	15	0	2
Storage	17	1	5

¹³⁰ See footnote 4.

a. Estimates of the number of new compressors were rounded to the nearest whole number.

12.1.3 Nationwide Emission Estimates

Nationwide baseline emission estimates for new reciprocating and centrifugal compressors are summarized in Table 12-2 by industry segment.

Table 12-2. Nationwide Baseline Emissions for New Reciprocating and Centrifugal Compressors for Projected Years 202 and 2025

Compressor Location/Compressor Type	Nationwide Baseline Emissions (tpy)	
	Methane	VOC
Projected Year 2020		
Transmission		
Reciprocating Compressors	2,035	56
Wet Seal Centrifugal Compressors	0	0
Storage		
Reciprocating Compressors	2,401	675
Wet Seal Centrifugal Compressors	585	16
Projected Year 2025		
Transmission		
Reciprocating Compressors	4,070	113
Wet Seal Centrifugal Compressors	0	0
Storage		
Reciprocating Compressors	,4802	133
Wet Seal Centrifugal Compressors	1,169	32

12.2 Nationwide Emission Reductions and Cost Impacts of Selected Regulatory Options

Tables 12-3 and 12-4 summarize the impacts of the selected regulatory options by industry segment. Regulatory Option 1 is estimated to affect 15 reciprocating compressors at transmission facilities and 17 reciprocating compressors at underground storage facilities in a typical year. The nationwide impacts for projected year 2020 are based on a typical year. The projected affected number of compressors for projected year 2020 is calculated as all compressors affected from 2016 through and including 2020 and for 2025 as all compressors affected from 2016 through and including 2025, assumed to still be in operation in the analysis years. A summary of the capital and annual costs and emission reductions for this option is presented in Table 12-3.

Operators in the gathering and boosting and transmission and storage parts of the industry typically do not own the natural gas they transport; rather, the operators receive payment for the transportation

service they provide. As a result, the unit-level cost and emission reduction analyses supporting BSER decisions in the preamble (and is presented in Volume 1 of the TSD) do not include estimates of revenue from natural gas recovery as offsets to compliance costs. From a social perspective, however, the increased financial returns from natural gas recovery accrues to entities somewhere along the natural gas supply chain and should be accounted for in the national impacts analysis. An economic argument can be made that, in the long run, no single entity is going to bear the entire burden of the compliance costs or fully receive the financial gain of the additional revenues associated with natural gas recovery. The change in economic surplus resulting from natural gas recovery is going to be spread out amongst different agents via price mechanisms. Therefore, the most simple and transparent option for allocating these revenues would be to keep the compliance costs and associated revenues together in a given source category and not add assumptions regarding the allocation of these revenues across agents. This is the approach followed in Volume 2 of the TSD, as well as in the RIA.

Regulatory Option 3 is expected to affect 1 new wet-seal centrifugal compressor in the transmission and storage segment (specifically at a storage facility) each year. The number of affected centrifugal compressors is low because the historical rate of growth in the overall number of wet seal centrifugal compressors in the segment has been low, indicating few new compressors are being installed. In addition, most new centrifugal compressors are expected to use dry seals, which would not be affected facilities. EPA did not change these activity numbers for the final rule. A summary of the capital and annual costs and emission reductions for this option is presented in Table 12-4. A summary of the nationwide secondary combustion-related emissions from Option 2 are summarized in Table 12-5.

Table 12-3. Nationwide Cost Impacts for Regulatory Option 1

Compressor Location	Number of New Sources	Nationwide Emission Reductions (tpy)		Total Nationwide Costs	Annualized Cost (\$/year)	
		Methane	VOC	Capital Cost (\$)	Without Savings	With Savings
Projected Year 2020						
Transmission	75	1,626	45	\$423,769	\$131,066	(\$205,534)
Storage	85	1,856	51	\$654,915	\$159,594	(\$207,676)
Projected Year 2025						
Transmission	150	3,252	90	\$847,537	\$262,132	(\$411,068)
Storage	170	3,712	103	\$1,309,830	\$353,049	(\$415,351)

Note: Negative number indicates net savings.

Table 12-4. Nationwide Cost Impacts for Regulatory Option 3

Compressor Location	Number of New Sources	Nationwide Emission Reductions (tpy)		Nationwide Costs			
		Methane	VOC	Capital Cost New CD ^a (\$)	Capital Cost Existing CD ^b (\$)	Annual Cost New CD ^a (\$/year)	Annual Cost Existing CD ^b (\$/year)
Projected Year 2020							
Transmission	0	0	0	\$0	\$0	\$0	\$0
Storage	5	555	21	\$358,914	\$116,260	\$570,728	\$16,553
Projected Year 2025							
Transmission	0	0	0	\$0	\$0	\$0	\$0
Storage	10	1,111	41	\$717,829	\$232,520	\$1,141,456	\$33,106

a. CD = Combustion Device Cost is based installation of a full system of control using a combustion device.

b. Cost is based on routing compressor to an existing combustion device.

Table 12-5. Nationwide Secondary Impacts from Compressor Emissions Routed to a Combustion Device

Compressor Location	Secondary Impacts (tpy)				
	THC ^a	CO ^b	CO ₂ ^c	NO _x ^d	PM ^e
Projected Year 2020					
Storage	2.9	6.4	2,748	1.4	0.05
Projected Year 2025					
Storage	5.8	13	5,496	2.8	0.10

a. Based on combustion of natural gas stream and AP-42 Total Hydrocarbons emission factors for industrial flares.

b. Based on combustion of natural gas stream and AP-42 Carbon Monoxide emission factors for industrial flares.

c. Based on combustion of natural gas stream and 40 CFR Part 98, subpart Y, Equation Y-2.

d. Based on combustion of natural gas stream and AP-42 Nitrogen Oxides emission factors for industrial flares.

e. Based on combustion of natural gas stream and AP-42 Particulate Matter emission factors for industrial flares. Assumes a “lightly smoking” flare.

13.0 NATURAL GAS SAVINGS

Affected facilities under the NSPS may recover natural that would have otherwise been vented or combusted as a result of controlling emissions. This section presents the value of recovered gas nationally.¹³¹ With respect to the regulatory options presented above, there are several opportunities for gas savings to be realized, as noted below:

- For oil well completions, with implementation of a REC, the EPA estimated that 899 Mcf of natural gas is recovered during the average 3-day completion event.
- For equipment leaks, with implementation of the semiannual OGI monitoring and repair of leaks found, the EPA estimate that the average annual gas saved would be 43 Mcf for oil wells with GOR < 300, 96 Mcf for oil wells with GOR > 300, 191 Mcf for gas wells, 1,222 Mcf for gathering and boosting stations, 1,255 Mcf for transmission stations, and 4,424 for storage facilities. For quarterly monitoring and repair, the EPA estimate for average annual gas saved would be 57 Mcf for oil wells with GOR < 300, 127 Mcf for oil wells with GOR > 300, 255 Mcf for gas wells, 1,629 Mcf for gathering and boosting stations, 1,673 Mcf for transmission stations, and 5,899 for storage facilities.
- For pneumatic controllers, the EPA estimate the use of low-bleed controllers instead of high-bleed controllers will save 147 Mcf of natural gas per year.
- For reciprocating compressors, the EPA estimate that the replacement of rod packing every 26,000 hours of operations (or every three years) will avoid the loss of, for each reciprocating compressor, 1,122 Mcf per year for transmission facilities and 1,130 Mcf per year for storage facilities.¹³²
- For centrifugal compressors, the EPA estimates that the replacement of one wet seal compressor with a dry seal compressor will save 5,290 Mcf per year.¹³³

Based on the above per unit natural gas savings and the new source activity counts anticipated for the projected years 2020 and 2025 for the affected facilities, the EPA calculated

¹³¹ Note that operators in the gathering and boosting and transmission and storage segments of the industry typically do not own the natural gas they transport; rather, the operators receive payment for the transportation service they provide. As a result, the unit-level cost supporting BSER decisions in the preamble (and is presented in Volume 1 of this TSD) do not include estimates of revenue from natural gas recovery as offsets to compliance costs. This section addresses all gas savings regardless of presumed ownership.

¹³² See footnote 2.

¹³³ See footnote 2.

the nationwide gas savings for each of the regulatory options discussed in the sections above for the projected years 2020 and 2025. Table 13-1 presents the estimated gas savings for these affected facilities.

Table 13-1. Estimated Nationwide Natural Gas Savings for Selected Regulatory Options

Affected Facility	Number of Affected Facilities Subject to NSPS ^a	Volume of Gas Saved (MMcf)	Value of Gas Saved (\$ million)
Projected Year 2020			
<i>Well Completions</i>			
Development Oil Wells	19,703	5,738	\$23
<i>Equipment Leaks</i>			
Oil Well Site ^b	76,759	5,633	\$22.5
Gas Well Site ^b	16,819	3,214	\$12.9
Gathering ^c	480	782	\$3.1
Transmission ^c	20	33	\$0.13
Storage ^c	25	147	\$0.59
Pneumatic Controllers	480	70.6	\$0.28
Pneumatic Pumps	3,946	0	\$0.00
Reciprocating Compressors - Transmission	75	84	\$0.34
Reciprocating Compressors - Storage	85	96	\$0.38
Centrifugal Compressors - Storage	5	26	\$0.10
Total Projected Year 2020	122,343	15,824	\$63
Projected Year 2025			
<i>Well Completions</i>			
Development Oil Wells	20,988	6,098	\$24.4
<i>Equipment Leaks</i>			
Oil Well Site	156,809	11,508	\$46
Gas Well Site	34,487	6,590	\$26.4
Gathering	960	1,564	\$6.3
Transmission	40	67	\$0.27
Storage	50	295	\$1.8
Pneumatic Controllers	960	141	\$0.56
Pneumatic Pumps	7,892	0	\$0
Reciprocating Compressors - Transmission	150	168	\$0.67
Reciprocating Compressors - Storage	170	192	\$0.77
Centrifugal Compressors - Storage	10	53	\$0.21
Total Projected Year 2025	230,407	26,676	\$107

a. Reflects only the number of affected facilities subject to the NSPS that will have potential gas savings (not all sources will have potential for gas savings).

b. For oil wells, the activity number reflects both oil well sites with GOR < 300 and oil well sites with GOR > 300. The gas savings for well sites are based on semiannual monitoring and repair.

c. The gas savings for compressor stations are based on quarterly monitoring and repair.

14.0 POTENTIAL NATIONWIDE CO₂ Eq. and HAP IMPACTS

Because methane is of concern for global warming effects, the EPA also calculated the global warming potential expressed as CO₂ Eq. for the methane reductions from the proposed regulatory options. For the purposes of this analysis, one ton of methane is equal to 25 tons of CO₂ Eq. The EPA have converted the CO₂ Eq. values to metric tonnes consistent with the presentation of CO₂ Eq. in the GHG Inventory.

In addition, there may be important HAP emission co-reductions a resulting from the application of emission controls under the NSPS. For the purposes of the NSPS, the EPA estimate HAP emissions by applying a ratio to the methane emissions. The ratio used is based on the gas composition analysis conducted for the NSPS.¹³⁴ Because gas composition was determined to vary between industry segments and between the various affected facilities, different ratios were used accordingly. Table 14-1 summarizes the HAP-to-methane ratios used for the various affected facilities in the various segments. Based on the methane emission reductions estimated in the above sections for the respective affected facilities and regulatory options, the EPA estimated the HAP emissions.

Table 14-2 summarizes the CO₂ Eq. and HAP emission reductions calculated for the affected facilities based on the finalized regulatory options.

Table 14-1. HAP-to-Methane Ratios Used to Estimate HAP Emissions

Segment	Affected Facility	HAP-to-Methane Ratio
Production	HF Oil Well Completions	0.0001
	Equipment Leaks:	
	Oil Well sites	0.0105
	Gas Well Sites	0.0105
	Gathering and Boosting	0.0105
Transmission	Pneumatic Pumps	0.0105
	Equipment Leaks	0.000822
	Pneumatic Pumps	0.000822
	Pneumatic Controllers	0.000822
	Reciprocating Compressors	0.000822
Storage	Equipment Leaks	0.000822
	Pneumatic Pumps	0.000822
	Pneumatic Controllers	0.000822
	Reciprocating Compressors	0.000822
	Centrifugal Compressor	0.000822

¹³⁴ See footnote 3.

Table 14-2. HAP and CO₂ Eq. Reductions for Selected Regulatory Options

Affected Facility	Number of Sources Subject to NSPS	Nationwide Emission Reductions			
		Methane (tpy)	VOC (tpy)	HAP (tpy)	CO ₂ e (MT/year)
Projected Year 2020					
HF Oil Well Completions					
All Oil Wells	19,703	115,880	97,038	12	2,628,121
Development Oil Wells	18,955	106,758	89,399	11	2,421,222
Exploratory/Delineation Oil Wells	748	9,123	7,639	1	206,899
Equipment Leaks					
Oil Well Site	76,759	97,201	26,465	997	2,204,483
Gas Well Site	16,819	55,455	15,415	581	1,257,695
Gathering & Boosting	480	13,495	3,751	141	306,056
Transmission	20	646	18	0.5	14,657
Storage	25	2,849	79	2.3	64,609
Pneumatic Controllers	480	1,338	37	1	30,335
Pneumatic Pumps	3,946	12,970	3,605	136	294,149
Reciprocating Compressors					
Transmission	75	1,626	45	1.3	36,881
Storage	85	1,856	51	1.5	42,094
Centrifugal Compressors – Storage	5	555	15	0.4	23,178
Total Projected Year 2020	118,397	303,871	146,519	1,874	6,902,258
Projected Year 2025					
HF Oil Well Completions					
All Oil Wells	20,988	123,461	103,386	12	2,800,048
Development Oil Wells	20,191	113,461	95,012	11	2,573,255
Exploratory/Delineation Oil Wells	797	10,000	8,374	1	226,793
Equipment Leaks					
Oil Well Site	156,809	198,569	54,065	2,037	4,503,477
Gas Well Site	34,487	113,709	31,608	1,191	2,578,877
Gathering	960	26,989	7,502	283	612,111

Affected Facility	Number of Sources Subject to NSPS	Nationwide Emission Reductions			
		Methane (tpy)	VOC (tpy)	HAP (tpy)	CO ₂ e (MT/year)
Transmission	40	1,293	36	1.1	29,314
Storage	50	5,698	158	4.7	129,218
Pneumatic Controllers	960	2,675	74	2	60,671
Pneumatic Pumps	7,892	25,940	7,210	272	588,299
<i>Reciprocating Compressors</i>					
Transmission	150	3,252	90	2.6	73,762
Storage	170	3,712	103	3.0	84,187
<i>Centrifugal Compressors</i>					
Storage	10	1,111	31	1	25,187
Total Projected Year 2025	222,516	506,409	204,263	3,810	11,485,151

15.0 COMPARISON OF TOTAL COST IMPACTS TO OVERALL INDUSTRY CAPITAL EXPENDITURES AND RECEIPTS

In order to provide another perspective on the reasonableness of the estimated cost of control as determined in our evaluation of BSER for the final standards as presented in Volume 1 of this TSD, we analyzed the total cost of the rule for each type of affected facility (as presented in Volume 2 of this TSD) under two additional approaches using industry economic data.

First, we compared the total nationwide capitals costs that would be incurred for each type of affected facility to comply with the final standards to the industry's estimated new annual capital expenditures. This analysis allowed us to compare the capital costs that would be incurred to comply with the final standards to the level of new capital expenditures that the industry is incurring in the absence of the final standards. Capital expenditure data for relevant NAICS codes covered by the rule were obtained from the U.S. Census 2013 Annual Capital Expenditures Survey¹³⁵. For the capital expenditures analysis, we determined the estimated nationwide capital costs estimated to be incurred by each type of affected facility to comply with the final standards¹³⁶, then divided the nationwide capital costs by the new capital expenditures (census data) for the appropriate NAICS code(s) to determine the percentage that the nationwide capital costs represent of the capital expenditures. For example, we used the total estimated capital cost (nationwide) for hydraulically fractured development oil well completions and compared that to the total capital expenditures the NAICs codes that correspond to oil and natural gas production segment. Table 15-1 below summarizes the capital expenditure data used for our analysis.

For fugitive emissions standards at well sites and compressor stations, there are no actual capital cost identified in the TSD. Instead, for the purposes of this portion of the analysis, we used the first-year corporate-based costs for these standards.

¹³⁵ Capital Expenditures for Structures and Equipment for Companies With Employees by Industry: 2013, Table 4a. See http://www.census.gov/econ/aces/xls/2013/full_report.html

¹³⁶ The total capital cost estimate is based on the number of estimated affected facilities within the year and the capital cost per facility, however, the capital expenditure may not actually be incurred in that year.

In the second approach, we compared the annualized costs that would be incurred to comply with the standards to the industry's estimated annual revenues. This analysis allowed us to determine whether the annualized costs appear reasonable as a percentage of the revenues being generated by the industry. The annualized cost, as calculated for the rule, includes capital cost annualized using a seven percent discount rate plus any annually incurred cost for implementation of a control technology. We included, where applicable, the cost savings realized from recovered natural gas. The annual revenue data for relevant NAICS codes were obtained from the U.S. Census 2012 County Business Patterns and 2012 Economic Census¹³⁷. For the annual revenues analysis, we determined the estimated nationwide annualized costs incurred by each type of affected facility to comply with the final standards¹³⁸, then divided the nationwide annualized costs by the annual revenues (Census data) for the appropriate NAICS code(s) to determine the percentage that the nationwide annualized costs represent of annual revenues. For example, we used the total annual cost (nationwide) for hydraulically fractured development oil well completions and compared that to the total receipts for the NAICS codes that correspond to oil and natural gas production segment. Table 15-2 below summarizes the revenue data used for our analysis.

For the capital expenditures, the production segment was represented with the NAICS codes 21111 "Crude Petroleum and Natural Gas Extraction" and 213111 and 213112 "Support Activities for Oil and Gas Operations". The transmission and storage segment was represented with the NAICS code 4862 "Pipeline transportation of natural gas". For revenue, the production segment was represented with the NAICS codes 21111 "Crude Petroleum and Natural Gas Extraction" and 213112 "Support Activities for Oil and Gas Operations". The transmission and storage segment was represented with the NAICS code 486210 "Pipeline transportation of natural gas". Although there is not a one-to-one correspondence between NAICS codes and the

¹³⁷ Number of Firms, Number of Establishments, Employment, Annual Payroll, and Estimated Receipts by Enterprise Employment Size for the United States, All Industries: 2012. Release date: 6/22/2015. 2012 County Business Patterns and 2012 Economic Census. For information on confidentiality protection, sampling error, and nonsampling error, see <http://www.census.gov/econ/susb/methodology.html>. For definitions of estimated receipts and other definitions, see <http://www.census.gov/econ/susb/definitions.html>.

¹³⁸ The estimated nationwide annualized costs were determined based on the estimated number of affected facilities in that year, however, these annualized costs are not necessarily incurred within that same year.

industry segments we used in the development of the analysis, we believe there is enough similarity to draw accurate conclusions.

Because we are aware the different owners or operators are generally involved in the different industry segments, we conducted the analysis at the affected facility level to ensure proper characterization of the impact. We also conducted the analysis for all sources in the production segment and in the transmission and storage segment. Table 15-3 summarizes the result of our analysis. In all cases we found that the rule impacts in comparison to either capital expenditures or revenues represent a fraction of one percent.

Table 15-1. NAICS-Based Capital Expenditure Data

Capital Expenditures Data (millions \$, current\$)			
Oil and Natural Gas Segment	NAICS code	NAICS DESCRIPTION	Total New Expenditures
Production	2111	Crude Petroleum and Natural Gas Extraction	\$158,911
	213111 213112	Support activities for oil and gas operations	\$19,966
Transmission and Storage	4862	Pipeline transportation of natural gas	\$12,891

Table 15-2. NAICS-Based Revenue Data

Revenue Data (millions \$, 2012\$)				
Oil and Natural Gas Segment	NAICS CODE	NAICS DESCRIPTION	ESTIMATED RECEIPTS (\$1,000)	ESTIMATED RECEIPTS (millions 2012\$)
Production	211111	Crude Petroleum and Natural Gas Extraction	\$276,076,578	\$276,077
	213112	Support Activities for Oil and Gas Operations	\$90,645,566	\$90,646
Processing	211112	Natural Gas Liquid Extraction	\$49,236,136	\$49,236
Transmission and Storage	486210	Pipeline Transportation of Natural Gas	\$26,587,330	\$26,587

Table 15-3. Comparison of Final NSPS OOOOa Nationwide Cost in 2025, by Affected Facility Cost to Industry Wide Capital Expenditures and Revenues

Oil and Natural Gas Segment/ Affected Facility	Number of Sources Subject to NSPS	Total Nationwide Capital Costs	Total Nationwide Annual Cost	Nationwide Capital Cost/ Capital Expenditures	Nationwide Annual Cost/Receipts
	Units	(million 2012\$)	(million \$)	(%)	(%)
<i>Production</i>					
Hydraulically Fractured Oil Well Completions and Recompletions	21,000	160	130	0.09	0.04
Pneumatic Pumps	8,000	43	6.1	0.02	0.00
Fugitives - Well Sites	190,000	150	365	0.09	0.10
Total Production Segment	219,000	353	501	0.20	0.14
<i>Transmission and Storage</i>					
Compressors					
- Reciprocating	320	2	1	0.02	0.00
- Centrifugal	10	\$1.1	1	0.06	0.04
Pneumatic Controllers	960	0	0	0.00	0.00
Fugitives - Compressor Stations	1,100	4	27	0.03	0.10
Total Transmission and Storage Segment	2,400	7	29	0.11	0.14

Source : All cost information is from the "Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, Background Technical Support Document for the Proposed New Source Performance Standards, 40 CFR Part 60, subpart OOOOa" available in the docket. For Hydraulically Fractured Oil Well Completions and Recompletions from Table 8-4, for Gas Driven Pumps from Table 11-4, for Fugitives - Well sites from Table 9-3, for Compressors, Reciprocating from Table 12-3, for Centrifugal from Table 12-4, for Pneumatic controllers from- Table 10-3, and for Fugitives - Compressor Stations from Table 9-4. The analysis results are rounded to two significant digits for this presentation. Capital costs reflect capital costs associated with affected facilities in 2025, including expenditures made prior to 2025.

APPENDIX A

MEMORANDUM

Development of the Low Pressure Well Equation for Determining REC Requirements at
Hydraulically Fractured Oil and Gas Wells



MEMORANDUM

FROM: ICF International

THRU: Graham Fitzsimons, EC/R

TO: Ravi Srivastava, U.S. EPA

DATE: April 29, 2016

SUBJECT: Technical Development of the Low Pressure Well Equation for Assessing REC Feasibility at Hydraulically Fractured Oil and Gas Wells

This memorandum documents the method for estimating flowback pressure during completion for a hydraulically fractured petroleum well to assess whether a Reduced Emissions Completion (REC) can be implemented. If the well does not have adequate pressure to push the produced natural gas into the flow line then the well is deemed a low pressure well. The memo provides background on low pressure wells, the technical development of the low pressure well equation (LPWE) and related correlations, comparison of LPWE predictions with those from an established well flow model, and an example calculation using the LPWE. A brief summary then follows the main body of this memo.

1. Background on Low Pressure Well Equation

REC is a practice in which the natural gas produced during a well completion is captured and routed through the flow line, following hydraulic fracturing. To successfully perform an REC, the pressure of the gas needs to be sufficiently high to push the gas into the flow line. If a well does not have adequate pressure to push the gas into the flow line then the well is deemed a low pressure well.

In the March 2015 New Source Performance Standards (NSPS) proposal, EPA proposed to use the definition for low pressure gas well provided in the 2012 final NSPS rule for all wells (i.e. oil and/or gas). According to this definition, the pressure of the flowback fluid, immediately before it enters the flow line, is calculated by the following equation:

$$P_L \text{ (psia)} = 0.445 \cdot P_R - 0.038 \cdot L + 67.578 \quad (1)$$

Where P_L (psia) is predicted flow line pressure (sales line pressure is sometimes used interchangeably with flow line pressure), P_R (psia) is reservoir pressure (synonymous with formation pressure), and L (ft) is true vertical depth of the well.

If the P_L calculated using the above equation is less than the available actual flow line pressure, the well would be considered to be a low pressure well. Such a well cannot implement an REC during completion flowback.

The above equation is not appropriate for application to oil wells. This effort was undertaken to develop an equation for predicting pressure of the flowback fluid just before the fluid enters the flow line and essentially modifies equation (1) to account for additional pressure drop due to flows of oil and water.

While detailed models are available for calculating multiphase flow in oil and gas wells, these models typically require many inputs, often complex, from an experienced user, the values of some of which may not be readily available before well completion activity is undertaken. The LPWE described in this memorandum uses only those inputs for which estimates are understood to be available before well completion activity starts including:

- Wellhead production rates (gas, oil, and water);
- Wellhead oil gravity;
- Reservoir pressure and bottomhole temperature; and
- True vertical well depth.

The three flow regimes typically encountered during the flowback event include:

- a. **Fracture fluid flow.** After hydraulic fracture (frack) of a new or existing well, the well tubing is filled with large quantities of frack fluid which consists of injected liquid (i.e., water plus additives) and proppant (typically sand). This material must be evacuated to prepare the well for production.

During the initial flowback, virtually all of the flow output from the well consists of the frack material itself, rather than hydrocarbons from the formation, given that the well tubing is filled with the frack fluid. As the frack fluid reaches the surface, it is typically directed to atmospheric pressure storage, typically a tank.

- b. **Slug flow.** As the column of frack fluid flows to the surface, it is followed by hydrocarbons (gas and oil) and water from the formation and any inert gas introduced during the frack. Because of the differences in density and viscosity of the various flowback components (oil, water, gas, and frack fluid), at this point the flowing fluid typically has multi-phase slugs of gas and liquid. As the slug flow reaches the surface, it is directed to temporary storage where the liquids portion of the slug flow is contained while the gas portion of the slug flow is typically vented to the atmosphere or sent to a completion combustion device.

- c. **Steady flow.** Over time (on the order of hours to days), the slug flow transitions to a steady flow condition where the frack fluid slugs in the tubing have been largely evacuated and there is a reasonably steady flow of hydrocarbons (oil and gas) and water. For energized fracks, this steady flow of vapor may, for a time, contain a significant percentage of the inert gas introduced into the formation during the frack, and over time, (on the order of hours) the steady flow transitions to primarily hydrocarbons and water from the formation. Depending upon the pressure of the fluid (oil, gas, and water) downstream of the wellhead, the steady flow of fluid can be directed to surface equipment and then to the flow line or a completion combustion device.

The LPWE developed in this document applies to the steady flow of hydrocarbons encountered during the separation flowback stage¹. Under this flow regime, gas may be separated and routed to the flow line.

2. Development of the Low Pressure Well Equation

Prior to developing the LPWE, research was performed to identify flow correlation models that adequately estimate the pressure drop across the well depth. In literature, a multitude of flow correlation models exist, ranging from simple pressure gradient models to complex mechanistic models. No flow correlation model is perfect and there is no model that can be applied to every situation. The hydrostatic pressure drop is typically the dominant component of pressure drop in wells. This component varies significantly with the gas-to-oil ratio, with higher volumes of oil significantly increasing the pressure drop due to oil having a higher density than gas. The frictional losses in wells constitute a small fraction of the total pressure drop across the entire well. Therefore, even for wells with horizontal section(s), it is the vertical section that determines the overall pressure drop characteristics. Hence for characterizing pressure drop in a well, it was important to focus on models that perform adequately for vertical wells. In general, the Hagedorn and Brown model² performs well for vertical wells, and is typically a good choice for such wells³.

All flow correlation models, including Hagedorn and Brown, typically require many inputs, often complex, from an experienced user, the values of some of which may not be readily available before well completion activity is undertaken. Therefore use of such models for determining REC requirements

¹ Separation flowback stage means the period during a well completion operation when it is technically feasible for a separator to function. The separation flowback stage ends either at the startup of production, or when the well is shut in and permanently disconnected from the flowback equipment.

² Hagedorn, A.R. and Brown, K.E., "Experimental study of pressure gradients occurring during continuous two-phase flow in small diameter vertical conduits," JPT, April 1965, 475.

<https://www.onepetro.org/journal-paper/SPE-940-PA>

³ Rao, B., "Multiphase Flow Models Range of Applicability", May, 1998,

<http://ctes.nov.com/documentation/technotes/Tech%20Note%20Multiphase%20Flow%20Models.pdf>.

could pose practical limitations. Consequently, a need was identified to develop a simpler model that could be used to determine whether an REC can be performed. The LPWE developed in this work uses only those inputs for which estimates are understood to be available before well completion activity starts.

The development of the LPWE starts from an energy balance that takes into account the two main components of pressure drop for oil and gas wells – hydrostatic and frictional. As such, the LPWE developed in this work modifies equation (1) to account for these components of pressure drop resulting from flow of oil and water in a well.

Under steady flow conditions during flow back, the flow of oil, gas, water, and proppant in well tubing can be visualized as a column of fluid⁴ experiencing⁵:

- The hydrostatic pressure drop due to the weight of the fluid column in the well tubing;
- Frictional pressure drop due to friction at the tubing walls opposing the flow to the surface;
- The pressure of the hydrocarbons and water at bottom hole conditions; and
- The pressure of the hydrocarbons and water at the well head.

Consequently⁶,

$$P_{WH} = P_{BH} - (\Delta P_g)_h - (\Delta P_o)_h - (\Delta P_w)_h - \Delta P_f \quad (2)$$

⁴ Pressure drop from horizontal sections of a well is assumed to be negligible compared to the vertical sections of the same well due to the hydrostatic pressure drop being the dominant component of total pressure drop compared to the frictional component in the lateral sections.

⁵ An additional force due to fluid acceleration is also present. Since this force contributes a negligible amount to total pressure drop across the well tubing, the impact of this force is ignored.

⁶ Hydrostatic pressure drop due to small amounts of proppant during separation flowback is implicit in the hydrostatic drop due to water.

Where P_{WH} is well-head pressure, P_{BH} is bottomhole pressure, $(\Delta P_g)_h$ is total hydrostatic pressure drop due to the gas phase, $(\Delta P_o)_h$ is total hydrostatic pressure drop due to the oil phase, $(\Delta P_w)_h$ is total hydrostatic pressure drop due to the water phase, and ΔP_f is total frictional pressure drop.

The pressure drop due to friction typically contributes a small amount to the overall total pressure drop, and it can be expressed as a percentage, $x(\%)$, of the total pressure drop:

$$\Delta P_f = x(\%) \cdot [(\Delta P_g)_h + (\Delta P_o)_h + (\Delta P_w)_h + \Delta P_f]$$

Simplifying and solving for pressure drop due to frictional losses:

$$\Delta P_f = \frac{x(\%) \cdot [(\Delta P_g)_h + (\Delta P_o)_h + (\Delta P_w)_h]}{[100 - x(\%)]} \quad (3)$$

Substituting equation (3) into equation (2) yields:

$$P_{WH} = P_{BH} - (\Delta P_g)_h - (\Delta P_o)_h - (\Delta P_w)_h - \frac{x(\%) \cdot [(\Delta P_g)_h + (\Delta P_o)_h + (\Delta P_w)_h]}{[100 - x(\%)]}$$

Simplifying further yields:

$$P_{WH} = P_{BH} - \left[\frac{100}{100 - x(\%)} \right] [(\Delta P_g)_h + (\Delta P_o)_h + (\Delta P_w)_h] \quad (4)$$

Now the pressure drops due to flow of gas, oil, and water can be expressed in terms of respective pressure gradients across the well. Then equation (4) can be written as,

$$P_{WH} (psia) = P_{BH} (psia) - \left[\frac{100}{100 - x(\%)} \right] \left[\left(\frac{\Delta P_g}{L} \right)_h + \left(\frac{\Delta P_o}{L} \right)_h + \left(\frac{\Delta P_w}{L} \right)_h \right] \left(\frac{psi}{ft} \right) \cdot L(ft) \quad (5)$$

Where L is the true vertical depth of the well, expressed in feet.

In the previous evaluation conducted for the 2012 NSPS, the flow line and bottom hole pressures for a gas well were expressed as:

$$P_L (psia) = \frac{P_{WH}}{1.01} (psia) \quad (6)$$

and

$$P_{BH} (psia) = \frac{P_R}{2} (psia) \quad (7)$$

These relationships are assumed to be generally applicable to flow in petroleum wells. Then, using these equations in equation (5) yields:

$$P_L (psia) = 0.495 \cdot P_R (psia) - 0.99 \left[\frac{100}{100-x(\%)} \right] \left[\left(\frac{\Delta P_g}{L} \right)_h + \left(\frac{\Delta P_o}{L} \right)_h + \left(\frac{\Delta P_w}{L} \right)_h \right] \left(\frac{psi}{ft} \right) \cdot L(ft) \quad (8)$$

Rewriting (8) in terms of densities (pounds/cubic foot) and the related volume fractions,

$$P_L (psia) = 0.495 \cdot P_R (psia) - \frac{0.99}{144^7} \cdot \left[\frac{100}{100-x(\%)} \right] \left[\frac{q_g}{q_g+q_o+q_w} \rho_g + \frac{q_o}{q_g+q_o+q_w} \rho_o + \frac{q_w}{q_g+q_o+q_w} \rho_w \right] \left(\frac{psi}{ft} \right) \cdot L(ft) \quad (9)$$

Where q_g , q_o , and q_w are the volumetric flowrates of gas, oil, and water in the well, respectively, expressed in cubic feet per second, and ρ_g , ρ_o , ρ_w , are the densities for the gas, oil, and water phases in the well, respectively, expressed in pounds per cubic feet.

2.1 Determination of hydrostatic and frictional pressure gradient due to gas flow

Under conditions of gas flow only, equation (9) becomes

$$P_L (psia) = 0.495 \cdot P_R (psia) - \frac{0.99}{144} \cdot \left[\frac{100}{100-x(\%)} \right] \rho_g \left(\frac{psi}{ft} \right) \cdot L(ft) \quad (10)$$

Comparing equations (1) and (10), we get,

$$\begin{aligned} & 0.445 \cdot P_R (psia) - 0.038 \cdot L(ft) + 67.578 \\ & = 0.495 \cdot P_R (psia) - \frac{0.99}{144} \cdot \left[\frac{100}{100-x(\%)} \right] \rho_g \left(\frac{psi}{ft} \right) \cdot L(ft) \end{aligned}$$

Simplifying,

⁷ 144 inches squared per foot squared.

$$\frac{0.99}{144} \cdot \left[\frac{100}{100-x(\%)} \right] \rho_g \cdot L = 0.05 \cdot P_R + 0.038 \cdot L(ft) - 67.578 (psi) \quad (11)$$

Substituting equation (11) into equation (9),

$$P_L (psia) = 0.495 \cdot P_R (psia) - \frac{q_g}{q_g+q_o+q_w} [0.05 \cdot P_R + 0.038 \cdot L(ft) - 67.578] - \frac{0.99}{144} \cdot \left[\frac{100}{100-x(\%)} \right] \left[\frac{q_o}{q_g+q_o+q_w} \rho_o + \frac{q_w}{q_g+q_o+q_w} \rho_w \right] \left(\frac{psi}{ft} \right) \cdot L(ft) \quad (12)$$

2.2 Determination of hydrostatic pressure gradient due to water flow

Generally a well can produce significant amounts of water while producing oil and gas. Therefore, it was important to take the water pressure gradient (psi/ft) into consideration when developing the LPWE. In the development of the LPWE the fresh water gradient of 0.433 psi/foot is used for calculating the hydrostatic pressure drop due to water⁸.

Then,

$$\frac{1}{144} \left[\frac{q_w}{q_g+q_o+q_w} \rho_w \right] \left(\frac{psi}{ft} \right) = \left[\frac{q_w}{q_g+q_o+q_w} 0.433 \right] \left(\frac{psi}{ft} \right) \quad (13)$$

Substituting (13) in (12) yields:

$$P_L (psia) = 0.495 \cdot P_R (psia) - \frac{q_g}{q_g+q_o+q_w} [0.05 \cdot P_R + 0.038 \cdot L(ft) - 67.578] - 0.99 \cdot \left[\frac{100}{100-x(\%)} \right] \left[\frac{q_o}{q_g+q_o+q_w} \cdot \frac{\rho_o}{144} + \frac{q_w}{q_g+q_o+q_w} 0.433 \right] \left(\frac{psi}{ft} \right) \cdot L(ft) \quad (14)$$

2.3 Determination of Estimated Frictional Pressure Drop (%)

As mentioned above, the Hagedorn and Brown flow model performs well for vertical wells and predicts both hydrostatic and frictional components of pressure drop based on the input conditions provided to

⁸ American Association of Petroleum Geologists: http://wiki.aapg.org/Hydrostatic_pressure-depth_plot_construction.

the model⁹. This model, henceforth referred to as the Hagedorn and Brown model, was coded in Excel by EPA and provided to ICFI. ICF checked the model and used it for validating the results of the LPWE. To evaluate the relative contribution of pressure drop due to frictional losses, an experimental matrix of model runs was created using known ranges of data from the DI Desktop™ commercial well database. These ranges are understood to cover the spectrum of oil and gas well characteristics relevant to the U.S.¹⁰. The experimental matrix is summarized in Table 1 below.

Table 1: Experimental Matrix of Input Variables for All Model Runs

Input Variable	Units	Values Used for All Model Runs
Oil Production Rate	Standard barrel per day	100, 200, 400, 800, 1000, 2000
Gas Production Rate	Million standard cubic feet per day	0.1, 0.3, 0.5, 1, 2, 3, 5, 10
Pressure Gradient ¹¹	psi per foot of well depth	0.35, 0.433, 0.5, 0.6, 0.75
Well Depth	Feet	500, 1000, 2500, 5000, 7000, 9000, 13000, 17000, 20000
Oil Wellhead Gravity	API	20, 30, 40, 50

Hagedorn and Brown model runs were completed and the pressure drop due to frictional losses was calculated as a percent of total pressure drop (hydrostatic and frictional). After evaluating over 7,560

⁹ The Hagedorn and Brown model used in this work calculates pressure drop gradient in psi/ft and multiplies the gradient by the well depth.

¹⁰ For purposes of this work, wells with Gas to Oil Ratios of 300 or less were excluded from the model runs. Additionally, few model runs with negative predicted values from either Hagedorn and Brown or the LPWE were considered infeasible and removed from the results.

¹¹ Increments of pressure gradient were multiplied against values of well depth to produce values of bottomhole pressure for each model run.

dynamic model runs¹², it was found that pressure drop due to frictional losses was close to 0.64% on average with a median value of 0.24%. As a conservative estimate, a value of 1% (i.e., x% = 1%) was assumed in this work to adequately characterize frictional pressure drop for operations typically encountered in U.S. oil production.

2.4 The Final Low Pressure Well equation

Assuming an average frictional component to total pressure drop ratio of 1% (i.e., x% = 1%) and substituting the value into (14), the final form of the LPWE becomes:

$$P_L (psia) = 0.495 * P_R (psia) - \frac{q_g}{q_g + q_o + q_w} [0.05 \cdot P_R + 0.038 \cdot L(ft) - 67.578] - \left[\frac{q_o}{q_g + q_o + q_w} \cdot \frac{\rho_o}{144} + \frac{q_w}{q_g + q_o + q_w} 0.433 \right] \left(\frac{psi}{ft} \right) \cdot L(ft) \quad (15)$$

The procedures for calculating oil, gas, and water flow rates and oil density to be used with the LPWE are described in Section 2.5.

Note under conditions of gas flow only (i.e., $q_o = q_w = 0$), equation (15) reduces to equation (1), the equation for gas wells. Also note that equation (15) for line pressure is derived using a vertical well. It is known that inclined wells exist in the field, which will experience a somewhat higher frictional drop due to longer flow length. Nonetheless, it is expected that equation (15) would be able to account for minor increases in pressure drop due to increased frictional drop at inclined wells because frictional pressure drop component contributes a small amount to the total pressure drop (about 1% on average) and conservative assumptions were used in deriving equation (15) – notably bottom hole pressure = ½ of formation pressure.

¹² In this work, two models were used: (1) a “dynamic model” including above-the-bubble point calculations, and (2) a “simplified dynamic model” (e.g. without above-the-bubble point calculations and with a constant value for dissolved gas gravity.)_ See Section 4 for more details.

In summary, equation (15) constitutes the LPWE developed in this work. This equation predicts the fluid pressure immediately upstream of the flow line. If this predicted pressure is higher than the available flow line pressure, the well can do an REC.

2.5 Determination of Oil Density, Oil Flow Rate, and Gas Flow Rate for Use in the LPWE¹³

2.5.1 Determination of Oil Density and Flow Rate

Oil density used in calculating the hydrostatic pressure drop for oil is defined as an arithmetic average of the oil density at bottomhole and the oil density at the wellhead. This accounts for the fact that the density of oil increases as the hydrocarbons move up the well and dissolved gases come out of the oil. The oil flow rate used in the LPWE corresponds to the flow rate at bottomhole conditions. In essence, starting with the bottomhole flow rate, the pressure drop across the well is calculated using this flowrate and the average oil density, and then the pressure at the wellhead is determined. This “marching” calculation procedure is also used in more complex multiphase flow models.

The oil density and volumetric flow rate at bottomhole conditions are calculated using the known values of oil API gravity and oil production rate (STBO/day) at a well site and the widely used correlations provided in Vasquez and Beggs (1980).¹⁴ This calculation procedure is described below¹⁵.

¹³ Equations marked by asterisks (*) are not original work developed by ICF and the relevant citations are provided. ICF received an approval through EPA from the Society of Petroleum Engineers on March 14th, 2016 for reproduction and use of equations and correlations from publications in their journals.

¹⁴ Vasquez, M. and Beggs, H.D., “Correlations for fluid physical property prediction,” JPT, June 1980, 968. This paper provides correlations for oil properties including dissolved gas-oil ratio and oil formation volume factor based on approximately 6000 data points - measured over large ranges of pressure, temperature, oil gravity and gas gravity.

<https://www.onepetro.org/journal-paper/SPE-6719-PA>

¹⁵ The calculation procedure uses correlations for flow conditions at or below bubble point. Runs of the Hagedorn and Brown model (see Table 1), with above-bubble-point correlations revealed that above-bubble-point conditions were met in less than 10% of all dynamic model runs (see Section 4) and above-bubble-point corrections amounted to oil density corrections on the order of 4% or less. Thus, the overall impact to predicted line pressure is considered to be relatively negligible and for simplicity above-bubble-point calculations are not included in the calculation procedure.

Step 1: Determine the value of the bottom hole pressure, P_{BH} , based on available information at the well site, or by calculating it using the reservoir pressure, P_R (psia), in the following equation:

$$P_{BH} \text{ (psia)} = \frac{1}{2} P_R$$

Step 2: Determine the value of the bottom hole temperature, T_{BH} (F), based on available information at the well site, or by calculating it using the true vertical depth of the well, L (ft), in the following equation¹⁶:

$$T_{BH} \text{ (F)} = 0.014 \times L + 79.081$$

Step 3: Calculate the value of the applicable natural gas specific gravity that would result from a separator pressure of 100 psig, γ_{gs} , using the following equation from Vasquez and Beggs (1980)¹⁴ with: separator at standard conditions (pressure, $p = 14.7$ (psia), temperature, $T = 60$ (F)); the API oil gravity at the well site, γ_o ; and the oil specific gravity at the separator under standard conditions, $\gamma_{gp} = 0.75$:¹⁷

$$\gamma_{gs} = \gamma_{gp} \cdot \left(1.0 + 5.912 \times 10^{-5} \cdot \gamma_o \cdot T \cdot \log \left(\frac{p}{114.7} \right) \right)^*$$

Step 4: Calculate the value of the applicable dissolved GOR, R_s (scf/STBO), using the following equation from Vasquez and Beggs (1980)¹⁴ with: the bottom hole pressure, P_{BH} (psia), determined in Step 1 above; the bottom hole temperature, T_{BH} (F), determined in Step 2 above;

¹⁶ Temperature gradient data from the United States Geological Service were regressed across the sedimentary basins in the US and modeled as a function of well depth. Data is derived from USGS Open-File Report 2010-1303 titled "Comprehensive Database of Wellbore Temperatures and Drilling Mud Weight Pressures by Depth for Judge Digby Field".

<https://pubs.er.usgs.gov/publication/ofr20101303>.

¹⁷ The value of 0.75 is based on expert opinion considering the average natural gas concentration data referenced in the technical memo titled "Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking," July, 2011, available in the NSPS OOOO rule making docket:

<https://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-0084>.

the gas gravity at separator pressure of 100 psig, γ_{gs} , calculated in Step 3 above; the oil API gravity, γ_o , at the well site; and the constants, C1, C2, and C3, found in Table 2:

$$R_s \left(\frac{\text{scf}}{\text{STBO}} \right) = C1 \cdot \gamma_{gs} \cdot P_{BH}^{C2} \cdot \exp \left[C3 \left(\frac{\gamma_o}{T_{BH} + 460} \right) \right]^*$$

Table 2. Coefficients for the Vasquez and Beggs Correlation for R_s .

Constant	$\gamma_{API} \leq 30$	$\gamma_{API} > 30$
C1	0.0362	0.0178
C2	1.0937	1.1870
C3	25.7240	23.931

Step 5: Calculate the value of the oil formation volume factor, B_o (bbl/STBO), using the following equation from Vasquez and Beggs (1980)¹⁴ with: the bottom hole temperature, T_{BH} (F), determined in Step 2 above; the gas gravity at separator pressure of 100 psig, γ_{gs} , calculated in Step 3 above; the dissolved GOR, R_s (scf/STBO), calculated in Step 4 above; the oil API gravity, γ_o , at the well site; and the constants, C1, C2, and C3, found in Table 3:

$$B_o \left(\frac{\text{bbl}}{\text{STBO}} \right) = 1.0 + C1 \cdot R_s + (T_{BH} - 60) \left(\frac{\gamma_o}{\gamma_{gs}} \right) \cdot (C2 + C3 \cdot R_s)^*$$

Table 3. Coefficients for the Vasquez and Beggs Correlation for B_o

Constant	$\gamma_{API} \leq 30$	$\gamma_{API} > 30$
C1	4.677×10^{-4}	4.670×10^{-4}
C2	1.751×10^{-5}	1.100×10^{-5}

C3	-1.811x10 ⁻⁸	1.337x10 ⁻⁹
----	-------------------------	------------------------

Step 6: Calculate the density of oil at the wellhead, $\rho_{WH} \left(\frac{lbm}{cu\ ft} \right)$, using the following equation with the value of the oil API gravity, γ_o , at the well site:

$$\rho_{WH} \left(\frac{lbm}{cu\ ft} \right) = \frac{141.5}{\gamma_o + 131.5} \times 62.4$$

Step 7: Calculate the density of oil at bottom hole conditions, $\rho_{BH} \left(\frac{lbm}{cu\ ft} \right)$, using the following equation with: the dissolved GOR, R_s (scf/STBO), calculated in Step 4 above; the oil formation volume factor, Bo (bbl/STBO), calculated in Step 5 above; the oil density at the wellhead,

$\rho_{WH} \left(\frac{lbm}{cu\ ft} \right)$, calculated in Step 6 above; and the dissolved gas gravity, $\gamma_{gd} = 0.77^{18}$:

$$\rho_{BH} \left(\frac{lbm}{cu\ ft} \right) = \frac{\rho_{WH} + 0.0136 \times R_s \times \gamma_{gd}}{Bo}$$

Step 8: Calculate the density of oil in the well, $\rho_o \left(\frac{lbm}{cu\ ft} \right)$, using the following equation with the density of oil at the wellhead, $\rho_{WH} \left(\frac{lbm}{cu\ ft} \right)$, calculated in Step 6 above; and the density of oil at bottom hole conditions, $\rho_{BH} \left(\frac{lbm}{cu\ ft} \right)$, calculated in Step 7 above:

$$\rho_o \left(\frac{lbm}{cu\ ft} \right) = 0.5 \times (\rho_{WH} + \rho_{BH})$$

¹⁸ Figure B-10 (Katz diagram) from Brill, J.P. and Mukherjee, H., "Multiphase Flow in Wells", Monograph Volume 17, SPE, 1999 was used to calculate the values of this variable in the model runs described in Section 2.4. It was found that dissolved gas gravity, γ_{gd} , did not have a significant impact on predicted flow line pressure. Therefore a value of 0.77 is recommended to be used for γ_{gd} . This value is the average of the values used in the dynamic model runs (see Section 4).

Step 9: Calculate the oil flow rate, q_o (cu ft/sec), using the following equation with: the oil formation volume factor, Bo (bbl/STBO), calculated in Step 4 above; and the estimated oil production rate at the well head, Q_o (STBO/day):

$$q_o \left(\frac{\text{cu ft}}{\text{sec}} \right) = Q_o \left(\frac{\text{STBO}}{\text{day}} \right) \times Bo \left(\frac{\text{bbl}}{\text{STBO}} \right) \times 5.614 \left(\frac{\text{cu ft}}{\text{bbl}} \right) \times \frac{1}{24 \times 60 \times 60} \left(\frac{\text{day}}{\text{sec}} \right)$$

2.5.2 Determination of Gas Flow Rate

As oil-gas-water mixture flows upwards in a well to a lower pressure location, gas volume changes and some of the dissolved gas evolves out of solution in oil. This results in gas volumetric flow (and therefore pressure gradient) changing with well depth.

The gas volumetric flow at bottomhole conditions is calculated in a sequential fashion, first evaluating terms to estimate gas compressibility factor, z . The Standing and Katz correlation and z -factor chart¹⁹ was used to estimate critical pressure and temperature at bottomhole conditions. Then, adjustments were made to the critical pressure and temperature according to the Carr/Kobayashi²⁰ method to account for potential impurities in the natural gas. Finally, the Brill and Beggs correlation for compressibility²¹ was utilized to estimate the z -factor. This calculation procedure is described below in detail:

Step 10: Calculate the critical pressure, P_c (psia), and critical temperature, T_c (R), using the aforementioned Standing and Katz correlation and Carr/Kobayashi adjustment with specific

¹⁹ Standing, M.B. and Katz, D.L., "Density of Natural Gases," Transactions of the AIME, SPE, December, 1942, 146.

<https://www.onepetro.org/journal-paper/SPE-942140-G>.

²⁰ To derive the equations, first adjustment factors for N₂, CO₂, and H₂S were obtained from Figure 8 in Carr, N. L., Kobayashi, R., and Burrows, D.B., "Viscosity of Hydrocarbon Gases Under Pressure," JPT, SPE, October, 1954, 6. Then these factors were applied to Standing and Katz correlations for P_c and T_c .

<https://www.onepetro.org/journal-paper/SPE-297-G>.

²¹ Guo, B., Ghalambor, A., "Natural Gas Engineering Handbook," Gulf Publishing Company, 2005, ISBN 0976511339, Chapter 2 equations 2.28 to 2.33.

gravity of gas at standard conditions ($p=14.7$ psia and $T = 60$ F), $SG = 0.75$; and where the mole fractions in the gas of nitrogen, carbon dioxide and hydrogen sulfide are: $X_{N_2} = 0.168225$, $X_{CO_2} = 0.013163$, and $X_{H_2S} = 0.013680^{22}$. The equations below for critical temperature and critical pressure represent the combined Standing correlation and Carr/Kobayashi adjustments into one form.

$$P_c(\text{psia}) = 678 - 50 \cdot (SG - 0.5) - 206.7 \cdot X_{N_2} + 440 \cdot X_{CO_2} + 606.7 \cdot X_{H_2S}^*$$

$$T_c(R) = 326 + 315.7 \cdot (SG - 0.5) - 240 \cdot X_{N_2} - 83.3 \cdot X_{CO_2} + 133.3 \cdot X_{H_2S}^*$$

Step 11: Calculate reduced pressure, P_r , and reduced temperature, T_r , using the following equations with: the bottom hole pressure, P_{BH} (psia), as determined in Step 1 above; the bottom hole temperature, T_{BH} (F), as determined in Step 2 above in the following equations:

$$P_r = \frac{P_{BH}}{P_c}$$

$$T_r = \frac{(T_{BH} + 460)}{T_c}$$

Step 12: Calculate the gas compressibility factor, Z , using the following Brill and Beggs correlation with the reduced pressure, P_r , calculated in Step 10 above:

$$Z = A + \frac{(1-A)}{e^B} + C \cdot p_r^{D*}$$

The values for A, B, C, D in the above equation, are calculated using the following equations with the reduced pressure, P_r , and reduced temperature, T_r , calculated in Step 10 above:

$$A = 1.39 \cdot (T_r - 0.92)^{0.5} - 0.36 \cdot T_r - 0.10$$

²² The mole fractions are the averages for compositions in oil and gas wells and are based on information in Table 8 in the technical memo titled "Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking," July, 2011, available in the NSPS OOOO rule making docket <https://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-0084>.

$$B = (0.62 - 0.23 \cdot T_r) \cdot P_r + \left(\frac{0.066}{(T_r - 0.86)} - 0.037 \right) \cdot P_r^2 + \frac{0.32}{10^{9 \cdot (T_r - 1)}} \cdot P_r^6$$

$$C = (0.132 - 0.32 \cdot \log(T_r))$$

$$D = 10^{0.3106 - 0.49 \cdot T_r + 0.1824 \cdot T_r^2}$$

Step 13: Calculate the gas formation volume factor, $B_g \left(\frac{cuft}{scf} \right)$, using the real gas law below with the bottom hole pressure, P_{BH} (psia), as determined in Step 1 above; and the bottom hole temperature, T_{BH} (F), as determined in Step 2 above:

$$B_g \left(\frac{cuft}{scf} \right) = 0.0283 \cdot \frac{Z \cdot (T_{BH} + 460)}{P_{BH}}$$

Step 14: Calculate the gas flow rate, $q_g \left(\frac{cuft}{sec} \right)$, using the following equation with: the value of gas formation volume factor, $B_g \left(\frac{cuft}{scf} \right)$, calculated in Step 12 above; the estimated gas production rate, Q_g (scf/day); the estimated oil production rate, Q_o (STBO/day); and the dissolved GOR, R_s (scf/STBO), as calculated in Step 4 above:

$$q_g \left(\frac{cf}{sec} \right) = (Q_g - R_s \cdot Q_o) \cdot B_g \cdot \frac{1}{24 \times 60 \times 60}$$

2.5.3 Determination of Water Flow Rate

Step 15: Generally, water is relatively incompressible and gas solubility in water is negligible.

Therefore, $q_w \left(\frac{cf}{sec} \right)$, the flow rate of water in the well, is calculated using the following equation with the water production rate Q_w (bbl/day) at the well site:

$$q_w \left(\frac{cf}{sec} \right) = Q_w \left(\frac{STB}{day} \right) \times 5.614 \left(\frac{cf}{bbl} \right) \times \frac{1}{24 \times 60 \times 60} \left(\frac{day}{sec} \right)$$

4. Comparison of the Low Pressure Oil Well Equation Results with those from the Hagedorn and Brown Model

As discussed previously, the Hagedorn and Brown flow correlation method generally predicts pressure drop for vertical wells better than the other models. The Hagedorn and Brown model was used for validating the results of the LPWE, equation (15). For validation purposes, model runs were completed using the experimental matrix shown in Table 1 above.

Over 7,560 model runs were performed using the coded Hagedorn and Brown model and simultaneously corresponding calculations were made with the LPWE (equation (15)). In this version of the Hagedorn and Brown model, called the dynamic model, certain calculations (i.e., bubble point pressure corrections and dissolved gas gravity) were completed using established correlations. While completing experimental matrix runs with the dynamic model, it was observed that correction for above-the-bubble point pressure and changes in dissolved gas gravity did not have a significant impact on model results (see footnotes 15 and 18). Consequently, a simplified dynamic model was created without above-the-bubble point calculations and with a fixed value for dissolved gas gravity (footnote 18). Subsequently, the same 7,560 model runs as above were completed with the simplified dynamic model. Results for line pressure from Hagedorn and Brown model runs are compared with corresponding results from the LPWE (equation (15)) in Figure 1 for the dynamic model case and in Figure 2 for the simplified dynamic model case.

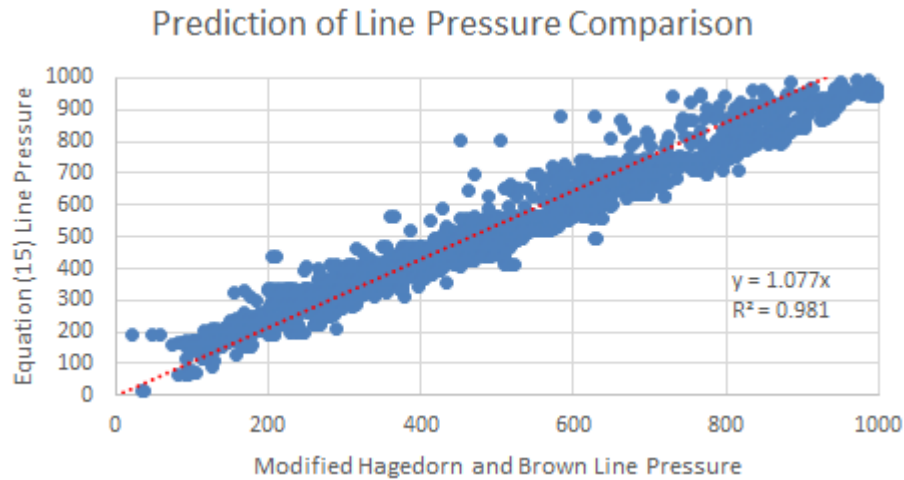


Figure 1: Comparison of Line Pressure Prediction for the Dynamic Model

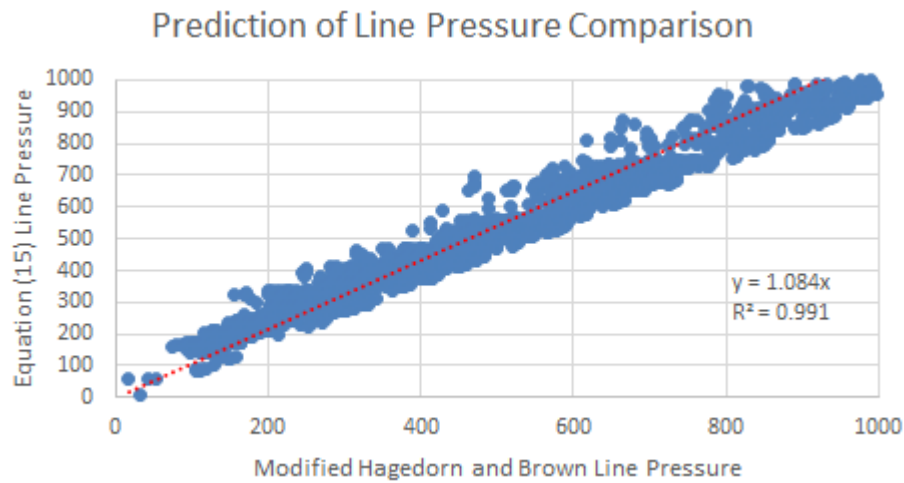


Figure 2: Comparison of Line Pressure Prediction for the Simplified Dynamic Model

Since the difference between Figure 1 and Figure 2 is negligible, the LPWE related calculation procedure described in Section 2.5 is appropriate. Finally, in addition to the comparison plots shown above, a multiple linear regression for line pressure predictions below 1000 psia was performed for data in Figure 2 and a standard error of 41 psia was observed²³. These results indicate that the LPWE estimates pressure drops comparable to the Hagedorn and Brown model.

²³ The standard error in this context represents an over-prediction of line pressure by 41 psia on average for equation (15) when compared to the Hagedorn and Brown method.

5. Example Calculation

For the example calculation with the LPWE, input conditions (illustrative example) are defined as follows:

- Well depth, $L = 7,900$ feet
- Reservoir pressure, $P_R = 2,700$ psia
- Bottomhole temperature, $T_{BH} = 180$ °F
- Oil production rate, $Q_o = 465$ STBOD
- Water production rate, $Q_w = 45$ STBOD
- Gas production rate, $Q_g = 570,000$ scf/day
- API gravity, $\gamma_o = 25$
- Available flow line pressure= 150 psia

Calculation of Oil Density and Flow Rate

Step 1. Calculate the bottomhole pressure using (Step 1, Section 2.5):

$$P_{BH}(psia) = \frac{1}{2}(2,700 psia) = 1,350psia$$

Step 2. Determine the bottomhole temperature (Step 2, Section 2.5):

From the information provided,

$$T_{BH}(F) = 180 F$$

Step 3. Calculate gas gravity at from a separator pressure of 100 psig, γ_{gs} (Step 3, Section 2.5):

$$\gamma_{gs} = (0.75) \cdot \left(1.0 + 5.912 \times 10^{-5} \cdot 25 \cdot 60^\circ F \cdot \log \left(\frac{14.7 psia}{114.7} \right) \right) = 0.691$$

Step 4. Calculate dissolved GOR, R_s (Step 4, Section 2.5):

$$R_s \left(\frac{scf}{STBO} \right) = (0.0362) \cdot (0.691) \cdot (1,350 \text{ psia})^{1.0937} \cdot \exp \left[25.7240 \cdot \left(\frac{25}{180^\circ F + 460} \right) \right]$$

$$= 181.14 \left(\frac{scf}{STBO} \right)$$

Step 5. Calculate the volume formation factor for oil, B_o (Step 5, Section 2.5):

$$B_o \left(\frac{bbl}{STBO} \right) = 1.0 + (4.677 \cdot 10^{-4} \cdot 181.14 \left(\frac{scf}{STBO} \right) + (180^\circ F - 60) \left(\frac{25}{0.691} \right) \cdot \left(1.751 \cdot 10^{-5} - 1.811 \cdot 10^{-8} \cdot 181.14 \left(\frac{scf}{STBO} \right) \right) = 1.147 \left(\frac{bbl}{STBO} \right)$$

Step 6. Calculate the density of oil at the wellhead (Step 6, Section 2.5):

$$\rho_{WH} = \frac{141.5}{25 + 131.5} \cdot 62.4 = 56.42 \left(\frac{lb_m}{cuft} \right)$$

Step 7. Calculate the density of oil at bottomhole (Step 7, Section 2.5):

$$\rho_{BH} \left(\frac{lb_m}{cuft} \right) = \frac{56.42 + 0.0136 \cdot 181.14 \left(\frac{scf}{STBO} \right) \cdot 0.77}{1.147 \left(\frac{bbl}{STBO} \right)} = 50.86 \left(\frac{lb_m}{cuft} \right)$$

Step 8. Calculate the average oil density, ρ_o (Step 8, Section 2.5):

$$\rho_o \left(\frac{lb_m}{cuft} \right) = \frac{1}{2} \left[56.42 \left(\frac{lb_m}{cuft} \right) + 50.86 \left(\frac{lb_m}{cuft} \right) \right] = 53.64 \left(\frac{lb_m}{cuft} \right)$$

Step 9: Calculate the oil flow rate at bottomhole conditions (Step 9, Section 2.5):

$$q_o \left(\frac{cuft}{sec} \right) = 465 \frac{STBO}{Day} \cdot 1.147 \left(\frac{bbl}{STBO} \right) \cdot \left(\frac{5.614}{24 \cdot 60 \cdot 60} \right) = 0.0346 \left(\frac{cuft}{sec} \right)$$

Calculation of Gas Flow Rate

Step 10. Calculate critical pressure and temperature (Step 10, Section 2.5):

$$P_c = 678 - 50 \cdot (0.75 - 0.5) - 206.7 \cdot 0.168225 + 440 \cdot 0.013163 + 606.7 \cdot 0.01368$$

$$= 644.819 \text{ psia}$$

$$T_c = 326 + 315.7 \cdot (0.75 - 0.5) - 240 \cdot 0.168225 - 83.3 \cdot 0.013163 + 133.3 \cdot 0.01368$$

$$= 365.278 \text{ }^\circ R$$

Step 11. Calculate reduced pressure and temperature (Step 11, Section 2.5):

$$P_r = \frac{1,350 \text{ psia}}{644.819 \text{ psia}} = 2.094$$

$$T_r = \frac{640 \text{ }^\circ R}{365.278 \text{ }^\circ R} = 1.752$$

Step 12. Calculate gas compressibility factor, z (Step 12, Section 2.5):

$$A = 1.39 \cdot (1.752 - 0.92)^{0.5} - 0.36 \cdot 1.752 - 0.101 = 0.536$$

$$B = (0.62 - 0.23 \cdot 1.752) \cdot 2.094 + \left(\frac{0.066}{(1.752 - 0.86)} - 0.037 \right) \cdot (2.094)^2 + \frac{0.32}{10^{9 \cdot (1.752 - 1)}}$$

$$\cdot (2.094)^6 = 0.616$$

$$C = (0.132 - 0.32 \cdot \log(1.752)) = 0.054$$

$$D = 10^{0.3106 - 0.49 \cdot (1.752) + 0.1824 \cdot (1.752)^2} = 1.028$$

$$z = 0.537 + \frac{(1 - 0.537)}{e^{0.245}} + 0.054 \cdot (0.968)^{1.028} = 0.902$$

Step 13. Calculate the gas formation volume factor, B_g (Step 13, Section 2.5):

$$B_g \left(\frac{\text{cuft}}{\text{scuft}} \right) = 0.0283 \cdot \left(\frac{0.902 \cdot 640 \text{ }^\circ R}{1,350 \text{ psia}} \right) = 0.0121 \left(\frac{\text{cuft}}{\text{scuft}} \right)$$

Step 14. Calculate the volumetric flow rate of the gas (Step 14, Section 2.5):

$$q_g \left(\frac{\text{cuft}}{\text{sec}} \right) = \left(570,000 \left(\frac{\text{scf}}{\text{day}} \right) - 181.14 \left(\frac{\text{scf}}{\text{STBO}} \right) \cdot 465 \text{ stbod} \right) \cdot 0.0121 \left(\frac{\text{cuft}}{\text{scuft}} \right) \cdot \left(\frac{1}{24 \cdot 60 \cdot 60} \right)$$

$$= 0.0680 \left(\frac{\text{cuft}}{\text{sec}} \right)$$

Step 15. Express water flow rate in cu ft/sec (Step 13, Section 2.5):

$$q_w \left(\frac{\text{cuft}}{\text{sec}} \right) = 45 \frac{\text{STBO}}{\text{Day}} \cdot \left(\frac{5.614}{24 * 60 * 60} \right) = 0.0029 \left(\frac{\text{cuft}}{\text{sec}} \right)$$

Finally, the line pressure can be evaluated using equation (15) to determine predicted flow line pressure.

$$P_L (\text{psia}) = 0.495 \cdot 2,700(\text{psia})$$

$$\begin{aligned} & - \frac{0.068 \left(\frac{\text{cuft}}{\text{s}} \right)}{\left(0.068 \left(\frac{\text{cuft}}{\text{s}} \right) + 0.0346 \left(\frac{\text{cuft}}{\text{s}} \right) + 0.0029 \left(\frac{\text{cuft}}{\text{s}} \right) \right)} \left[0.05 \cdot 2,700(\text{psia}) \right. \\ & \left. + 0.038 \left(\frac{\text{psia}}{\text{ft}} \right) \cdot 7,900(\text{ft}) - 67.578(\text{psia}) \right] \\ & - 1.00 \left[\frac{0.0346 \left(\frac{\text{cuft}}{\text{s}} \right)}{\left(0.068 \left(\frac{\text{cuft}}{\text{s}} \right) + 0.0346 \left(\frac{\text{cuft}}{\text{s}} \right) + 0.0029 \left(\frac{\text{cuft}}{\text{s}} \right) \right)} \cdot \frac{53.641 \left(\frac{\text{lb}_m}{\text{cuft}} \right)}{144 \left(\frac{\text{psia}}{\left(\frac{\text{lb}_m}{\text{ft}^2} \right)} \right)} \right. \\ & \left. + \frac{0.0029 \left(\frac{\text{cuft}}{\text{s}} \right)}{\left(0.068 \left(\frac{\text{cuft}}{\text{s}} \right) + 0.0346 \left(\frac{\text{cuft}}{\text{s}} \right) + 0.0029 \left(\frac{\text{cuft}}{\text{s}} \right) \right)} \cdot 0.433 \left(\frac{\text{psia}}{\text{ft}} \right) \right] \\ & \cdot 7,900(\text{ft}) = 39.7(\text{psia}) \end{aligned}$$

Since $P_L = 39.7 \text{ psia} < \text{available flow line pressure} = 150 \text{ psia}$, the well may not be able to perform an REC. On the other hand, if the sales line pressure is below 39.7 psia, then the operator may be able to perform an REC within operational constraints.

6. Summary

This memo describes the development of the low pressure well equation, LPWE, appropriate for use at well sites to determine whether or not a well can implement an REC. This equation uses only those inputs for which estimates are understood to be available before well completion activity starts to calculate the flowback fluid pressure immediately upstream of the flow line. If the well does not have adequate pressure to push the produced natural gas into the flow line then the well can be deemed a low pressure well and may not be able to perform REC. The equation was tested against an established and widely used multiphase flow model using a range of conditions representative of wells in the U.S. The results from the equation were generally consistent with those from the established Hagedorn and Brown model.

Appendix

Additional analysis was performed to characterize oil and gas wells with respect to the low pressure well equation. The analysis informs assumptions about the proportion of hydraulically fractured well completions that would be considered low pressure using the low pressure well equation.

This document analyzes roughly 37,800 oil and gas wells across the United States and applies the low pressure well equation to each of the wells to determine a prediction of flow line pressure. Based on various filters described below, the wells were characterized in a set of tables. Finally, in addition to evaluating flow line pressure using the draft low pressure well equation, data from the Green House Gas Reporting Program (GHGRP) was utilized to determine average separator pressure and API gravity according to basin.

For all subsequent tables, wells were classified as low pressure wells if the predicted flow line pressure was less than the average separator pressure for the associated basin as reported in the GHGRP Subpart W for 2014. If the flow line pressure was greater than the average separator pressure, the well was classified as a high pressure well. Although in some cases there will be a dehydrator or other equipment downstream of the separator, which will result in a pressure drop, the separator pressure is the closest metric available to the flowline pressure, and was therefore used in this analysis.

Table 1 shows the distribution of oil and gas wells (identified using a GOR threshold of 100,000 scf/bbl) and whether the wells would be considered high pressure (HP) or low pressure (LP) using the LPWE. Table 2 performs the same analysis but excludes wells with GOR < 300 scf/bbl. Table 3 provides the oil and gas well splits with additional detail on basin type. Tables 1 through 3 are generated based on 2014 annual oil and gas production values²⁴.

²⁴ Values obtained from the DI Desktop™ commercial well database for well completions in 2014.

We assume that hydraulically fractured oil well completions occur in shale oil basins. While variations from this assumption are very likely, we believe this is a reasonable assumption for this analysis. **Based on this assumption and according to this analysis, about 40 percent (3,717 of 9,227 completions) for shale oil wells with GOR>300 scf/bbl would be considered low pressure using the low pressure well equation.**

Table 1: Oil and Gas Well Splits with Gas Well Cutoff of 100,000 scf/bbl including all GORs

Well Type	Total Count	HP Well Count	LP Well Count
Oil Well	35,793	14,583	21,210
Gas Well	2,015	1,918	97

Table 2: Oil and Gas Well Splits with Gas Well Cutoff of 100,000 scf/bbl excluding GORs <300

Well Type	Total Count	HP Well Count	LP Well Count
Oil Well	22,093	13,701	8,392
Gas Well	2,015	1,918	97

Table 3: Oil and Gas Well Splits by Basin Type for GORs > 300 with Gas Well Cutoff of 100,000 scf/bbl²⁵

Basin Type	Total Count	HP Well Count	LP Well Count
Conventional	12,505	8,770	3,735
<i>Oil</i>	11,288	7,616	3,672
<i>Gas</i>	1,217	1,154	63
Shale Oil	9,227	5,510	3,717
Tight Gas	1,953	972	981
Shale Gas	417	361	56
Coal Bed Methane	5	5	0

²⁵ The categories of shale oil, tight gas, and shale gas are based on the DI Database basin type designation. With the 100,000 scf/bbl cutoff, some of these wells could be classified as oil or gas wells but were not reclassified and the basin type designation was used to classify these wells.

REGULATORY ANALYSIS

for Proposed Revisions to
Colorado Air Quality Control Commission
Regulation Numbers 3, 6 and 7
(5 CCR 1001-5, 5 CCR 1001-8, and CCR 1001-9)



February 11, 2014

Colorado Department of Public Health and Environment

Air Pollution Control Division
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1 EXECUTIVE SUMMARY

The Colorado Air Pollution Control Division's ("Division's") proposed revisions to the Air Quality Control Commission's ("Commission's") Regulation Numbers 3, 6, and 7, collectively expand the air emission control requirements on oil and gas facilities in Colorado. They were developed after the Division's extensive, year-long stakeholder process leading up to the Commission's rulemaking hearing, including input from diverse industry, environmental and governmental stakeholders. The proposal has received the support of several industry and environmental leaders, including Anadarko Petroleum, Noble Energy, Encana Oil and Gas, and the Environmental Defense Fund. The proposal affects not only the oil and gas industry and supporting businesses in Colorado, but the Regulation Number 3 revisions broadly affect all businesses in Colorado. Further, the proposal broadly benefits all persons in Colorado, especially those who live and work in the proximity of oil and gas operations, given the anticipated emissions reductions that will be achieved and the reasonable associated cost of implementation. The Division estimates that the proposed strategies will result in substantial reductions of hydrocarbon emissions from the oil and gas industry. More specifically, the Division estimates the proposed strategies will reduce volatile organic compound (VOC) emissions by 93,500 tons per year, and methane/ethane emissions by 64,000 tons per year. The Division conservatively estimates that the annual net costs to industry of the Division's proposal will be \$42.4 million per year. This translates to approximately \$453 per ton of VOC reduced, which is very reasonable when compared to other air pollution reduction strategies adopted by the Colorado Commission and the U.S. Environmental Protection Agency (EPA). In prehearing submittals to the Commission, the supporters of the proposal have concluded that the Division's costs estimates methodology and cost estimates are reasonable. Some opponents of the proposal have asserted that the costs may be much higher. The Commission will consider the Division's proposal and any alternate proposals at the rulemaking hearing commencing February 19, 2014.

2 INTRODUCTION

On December 13, 2013, interested parties, stakeholders, and state representatives filed eleven separate requests for both a Cost Benefit Analysis and a Regulatory Analysis ("Requests") with the Division, per C.R.S. §24-4-103(2.5), C.R.S. §24-4-103(4.5) and the Commission's Procedural Rules, 5 CCR 1001-1, §V.E.13. This document satisfies the requirements for a Regulatory Analysis, and is separate from the related Cost-Benefit Analysis. Similarly, this Regulatory Analysis is different from, but related to, the required Economic Impact Analysis, C.R.S. §25-7-110.5(4). The Requests were specific to proposed revisions to the Commission's Regulation Numbers 3, Parts A, B, and C ("Regulation 3"); Regulation 6, Part A ("Regulation 6"); and Regulation Number 7 ("Regulation 7").

The Colorado Administrative Procedure Act (“APA”)¹ serves as the legal authority for this rulemaking process, and sets forth requirements for both cost-benefit and regulatory analyses. Under the APA, any person may request an agency engaged in a rulemaking to prepare a regulatory analysis.² The regulatory analysis must include:

- A description of the classes of persons who will be affected by the proposed rule, including classes that will bear the costs of the proposed rule and classes that will benefit from the proposed rule;
- To the extent practicable, a description of the probable quantitative and qualitative impact of the proposed rule, economic or otherwise, upon affected classes of persons;
- The probable costs to the agency and to any other agency of the implementation and enforcement of the proposed rule and any anticipated effect on state revenues;
- A comparison of the probable costs and benefits of the proposed rule to the probable costs and benefits of inaction;
- A determination of whether there are less costly methods or less intrusive methods for achieving the purpose of the proposed rule; and
- A description of any alternative methods for achieving the purpose of the proposed rule that were seriously considered by the agency and the reasons why they were rejected in favor of the proposed rule.
- To the extent practicable, a quantification of the data used in the analysis; the analysis must take into account both short-term and long-term consequences.³

So long as the regulatory analysis is undertaken in good faith, it satisfies the APA.⁴

This Regulatory Analysis evaluates the Division’s November 15, 2013 proposed revisions to Regulations 3, 6, and 7, as amended on January 30, 2014, using information gathered through the Division’s Cost Benefit Analysis, and Economic Impact Analyses, and other documents associated with the administrative record for the February 19-23, 2014 Commission Hearing.

The Division’s proposed revisions to Regulation 3, 6, and 7 are part of an overall effort to fully adopt federal Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution found in 40 C.F.R. Part 60, Subpart OOOO (“NSPS OOOO”), by incorporating them into Regulation Number 6, Part A, and making the corresponding revisions to the Regulation Number 3 catch-all provisions to address barriers that prevented full adoption of NSPS OOOO. The proposal also revises Regulation Number 7 to address differences and overlaps between NSPS OOOO and Regulation Number 7 oil and gas control requirements, and to further reduce hydrocarbon emissions and leaks from oil and gas facilities. These revisions include:

1. Expanding Colorado’s adoption of NSPS OOOO, such that it is adopted in full (Regulation 6);
2. Removing “catch-all” provisions (Regulation 3);

¹ See C.R.S. § 24-4-101 *et. seq.*

² *Id.* at § 24-4-103(4.5)

³ *Id.*

⁴ *Id.* at § 24-4-103(2.5)(d) & § 24-4-103(4.5)(d).

3. Removing crude oil storage tank permitting exemptions (Regulation 3);
4. Expanding condensate tank control requirements state-wide, including establishing storage tank emission monitoring (“STEM”) requirements (Regulation 7);
5. Expanding dehydration unit (“dehy”) control requirements state-wide (Regulation 7);
6. Establishing leak detection and repair (“LDAR”) requirements for components at well production facilities and natural gas compressor stations state-wide (Regulation 7);
7. Establishing well maintenance and liquids unloading requirements state-wide (Regulation 7); and
8. Expanding pneumatic controller requirements state-wide (Regulation 7).

In addition to these more prominent revisions, these proposals also correct minor administrative errors, and make typographical, grammatical, and formatting changes in Regulation 3, 6, and 7. This Regulatory Analysis focuses on the more significant revisions and does not address typographical, grammatical, and formatting changes.

This analysis represents information gathered from various stakeholders in an effort to generate the most complete and accurate assessment of the costs and benefits of the proposed strategies. Where data was not reasonably available, the Division utilized assumptions that are set forth in this analysis.

3 ANALYSIS

3.1 Regulation Number 6

3.1.1 Proposed Revisions

The proposed revisions to Regulation 6 fully incorporate by reference the federal NSPS OOOO into Regulation Number 6, Part A, including the provisions not incorporated during the Commission’s partial adoption. In late 2012, the Commission partially adopted the Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution found in 40 C.F.R. Part 60, Subpart OOOO (“NSPS OOOO”), such that Colorado currently administers NSPS OOOO, for all affected facilities under NSPS OOOO including centrifugal compressors, reciprocating compressors, pneumatic controllers, storage vessels, process unit equipment, and sweetening units, except for natural gas wells (well completion requirements) and equipment that emits less than current reporting and permitting thresholds. At that time, the Commission directed the Division to consider full adoption of NSPS OOOO, as well as other improvements to Colorado’s oil and gas emission regulations.

It appears that all parties to the Commission rulemaking support the proposed revisions to Regulation 6.

3.1.2 Class of Persons Affected

“A description of the classes of persons who will be affected by the proposed rule, including classes that will bear the costs of the proposed rule and classes that will benefit from the proposed rule.”

There is limited impact associated with this proposal, in that NSPS OOOO is already in effect on a federal level and the Commission has already partially adopted NSPS OOOO for Colorado. The classes of persons affected by the proposed full adoption of NSPS OOOO include oil and gas companies operating in Colorado, and businesses that support the oil and gas industry in Colorado. Also, citizens statewide are impacted by the proposal. In all cases, it is simpler and less confusing to no longer have to deal with federal and state agencies administering the same requirements.

Full adoption of NSPS OOOO does not have an additional cost impact on any affected classes of persons because this rule is currently in effect and federally enforceable. Full adoption of NSPS OOOO does not provide additional health or economic benefits to classes of persons affected by the proposal because NSPS OOOO is currently in effect and federally enforceable. However, affected classes of persons will benefit from the proposed full adoption of NSPS OOOO due to having Colorado implement and enforce NSPS OOOO for all sources subject to NSPS OOOO in Colorado.

Further, full adoption of NSPS OOOO benefits the United States Environmental Protection Agency (“EPA”) by relieving the agency of the primary responsibility to implement and enforce NSPS OOOO in Colorado.

The Colorado Oil and Gas Conservation Commission (“COGCC”) does have well completion requirements that are different but similar to NSPS OOOO requirements. However this proposal to fully adopt NSPS OOOO does not change the fact that there are two different requirements that may apply to natural gas wells. The Division continues to work with the COGCC to address this issue and coordinate implementation of these rules.

3.1.3 Quantitative and Qualitative Impacts

“To the extent practicable, a description of the probable quantitative and qualitative impact of the proposed rule, economic or otherwise, upon affected classes of persons.”

There are few if any additional quantitative impacts of the Regulation 6 proposal because these rules are already in effect on a federal level. The qualitative impact of the proposed rule upon affected classes of persons includes Colorado’s implementation and enforcement of NSPS OOOO, using Division staff much more familiar with Colorado’s oil and gas issues than EPA staff. Full adoption of NSPS OOOO does not provide any other additional costs or benefits beyond those affected by NSPS OOOO.

3.1.4 Probable Agency Costs

“The probable costs to the agency and to any other agency of the implementation and enforcement of the proposed rule and any anticipated effect on state revenues.”

The probable costs to the Division of implementing and enforcing the NSPS OOOO requirements for affected facilities below current Air Pollutant Emission Notice (“APEN”) reporting and minor source permitting thresholds, as well as implementing and enforcing the NSPS OOOO well completion requirements, are unknown at this time. These sources are not currently subject to Colorado’s reporting and permitting requirements.

The Division will largely implement the provisions of its proposal through its oil and gas inspection team. This team currently consists of nine full time inspectors and four term limited inspectors. In 2012, in response to the growth in the oil and gas industry in Colorado, the legislature approved increasing the size of the inspection team from six inspectors to nine. In 2013, the legislature appropriated additional funds to hire four term limited inspectors to conduct IR camera inspections at well production facilities in Colorado. The term for these positions runs through June of 2015, but could be extended by the legislature if warranted. The additional inspectors provided during the 2012 and 2013 legislative sessions has significantly expanded the capabilities of the oil and gas inspection team, which will further enable the Division to implement and enforce the proposed requirements if the Commission chooses to adopt the Division’s proposal. The total projected annual cost to the Division for the oil and gas inspection team in fiscal year 2013-14 is \$1,305,304, which includes salary costs, fringe benefits, operating costs (including vehicles, field equipment, and office equipment), travel training and indirect costs.

There is no anticipated effect on state revenues because the proposal does not assess any additional emissions reporting or permitting fees than those that already apply.

3.1.5 Comparison to Inaction

“A comparison of the probable costs and benefits of the proposed rule to the probable costs and benefits of inaction.”

If the Commission does not fully adopt NSPS OOOO, EPA and the Division will continue to share the implementation and enforcement responsibilities for NSPS OOOO. However, regardless of partial or full adoption, NSPS OOOO remains effective and federally enforceable.

Importantly, the Division does not advocate full adoption of NSPS OOOO without removing the catch-all provisions in Regulation Number 3 due to the reporting and permitting impacts on both the regulated community and the Division.

3.1.6 Less Costly Methods/Less Intrusive Methods

“A determination of whether there are less costly methods or less intrusive methods for achieving the purpose of the proposed rule.”

There are no less costly or intrusive methods for achieving full adoption of NSPS OOOO. Retaining partial adoption of NSPS OOOO will not resolve the issue of shared implementation responsibilities between EPA and the Division.

3.1.7 Alternative Methods

“A description of any alternative methods for achieving the purpose of the proposed rule that were seriously considered by the agency and the reasons why they were rejected in favor of the proposed rule.”

The Division did not consider any alternative methods for achieving full adoption of NSPS OOOO.

3.1.8 Quantification of Data

“To the extent practicable, a quantification of the data used in the analysis; the analysis must take into account both short-term and long-term consequences.”

The short and long term consequences of the full adoption of NSPS OOOO are full implementation and enforcement by Colorado, instead of split implementation and enforcement between EPA and Colorado. The Division did not further quantify the short- or long-term consequences of the Regulation 6 proposal to fully adopt NSPS OOOO beyond what was already performed by EPA.

3.2 Regulation Number 3

3.2.1 Proposed Revisions

The Division is proposing revisions to Regulation 3’s reporting and permitting requirements in order to improve the efficiency of Colorado’s air quality reporting and permitting system.

The proposed revisions remove the requirement for sources subject to either a federal New Source Performance Standard (“NSPS”) or federal National Emission Standards for Hazardous Air Pollutant (“NESHAP”)/Maximum Available Control Technology (“MACT”) adopted into Regulation Number 6, Part A or Number 8, Parts A, C, D, and E to file an APEN and obtain a minor source permit regardless of whether their emissions exceed the reporting or permitting thresholds (“catch-all provisions”). As a result, sources subject to a NSPS incorporated into Regulation Number 6, Part A or a NESHAP/MACT incorporated into Regulation Number 8,

Parts A, C, D, or E are subject to APEN reporting and permitting **only** if their emissions exceed the applicable APEN and permitting thresholds.

In addition, the proposed revisions simplify the Appendix A non-criteria reportable pollutant de minimis determination to 250 pounds per year of any individual non-criteria reportable pollutant. The proposed revisions also remove the crude oil storage tank permitting exemptions.

Finally, the proposed revisions correct an inadvertent error to the minor source permitting exemption for crude oil and condensate truck loading equipment. This revision is administrative in nature, as the Division currently implements the provision as it was originally intended.

It appears that all parties to the Commission rulemaking support the proposed revisions to Regulation 3, and some parties have submitted alternative proposals requesting additional revisions (see Section 3.2.7 in this Regulatory Analysis).

3.2.2 Class of Persons Affected

“A description of the classes of persons who will be affected by the proposed rule, including classes that will bear the costs of the proposed rule and classes that will benefit from the proposed rule.”

The classes of persons affected by the proposed revisions to Regulation 3 are broad. Revisions to the catch-all provisions affect any stationary source subject to an NSPS adopted into Regulation Number 6 or NESHAP/MACT adopted into Regulation Number 8 that has emissions below the APEN reporting and minor source permitting thresholds. To demonstrate the breadth of impact, some examples of business and industry that are affected include dry cleaners, aggregate mining operations, grain elevators, natural gas compressor stations, surface coating operations, and power plants. Those activities subject to an NSPS or NESHAP/MACT, whose emissions fall below current reporting and permitting thresholds, will no longer have to report emissions and obtain minor source permits.

The proposed revisions to the non-criteria reportable pollutant de minimis threshold will affect stationary sources with emissions of non-criteria reportable pollutants greater than 250 pounds per year. This revision also has a broad impact, as most sources emit some degree of hazardous air pollutants or other non-criteria reportable pollutants.

Further, the revisions to the crude oil storage tank permit exemptions affect owners and operators of crude oil storage tanks with capacities of 40,000 gallons or less. The correction to the minor source permitting exemption for crude oil and condensate truck loading equipment is administrative in nature and affects oil and natural gas operations.

3.2.3 Quantitative and Qualitative Impacts

“To the extent practicable, a description of the probable quantitative and qualitative impact of the proposed rule, economic or otherwise, upon affected classes of persons.”

Quantitative and qualitative consequences for each revision are discussed below. Short- and long-term consequences include the continued delay in adopting NSPS OOOO in full, as well as other federal NSPS and NESHAP/MACT that apply to small sources in Colorado. There are minimal if any costs to the regulated community due to these revisions, and in some cases, cost savings are anticipated. Further, the Division anticipates that there will be no significant environmental impact associated with the proposal.

3.2.3.1 Catch-all Provisions

There are no anticipated costs to either the regulated community or the government associated with these proposed revisions. Removal of the catchall provisions will actually reduce reporting, permitting, and associated cost burdens for the regulated community. By reducing reporting and permitting activities, the proposed revision will also reduce costs to the Division associated with these activities.

The Division conducted a permit tracking project from February, 2013 to September, 2013 to understand the impact of this proposal. All pre-construction permits issued were evaluated to determine if they would have required an APEN and permit under this proposal. The Division's permit tracking project indicated that 7% (167 of 2,355) permits processed required permits solely due to the catch-all provision, accounting for approximately 0.03% of the total uncontrolled actual criteria pollutant emissions and 0.003% of statewide uncontrolled actual criteria pollutant emissions. The total hourly permit processing fees for these permits was approximately \$50,000.⁵ This cost estimate does not include the time saved by the sources by no longer having to complete and submit an APEN or minor source permit application.

The environmental impacts of revising the catch-all provisions are minimal. Further, no emissions increases are anticipated from these sources that would no longer require a permit because these revisions will not exempt them from having to comply with the requirements of an applicable NSPS or NESHAP/MACT.

3.2.3.2 Non-criteria Reportable Pollutants

Some stationary sources affected by the proposed revisions to the non-criteria reportable pollutant thresholds may have new costs related to reporting emissions previously below reporting thresholds, including filing and annual fees. Revision of the threshold for non-criteria reportable pollutants could result in either cost savings or additional costs to the regulated community depending on the source. Sources that are required to report hazardous air pollutants (a subset of non-criteria reportable pollutants) must pay an emission fee of \$152.90 per ton. Currently Regulation Number 3 contains a complex reporting formula involving multiple and different thresholds, some of which are above and some of which are below the proposed 250 pound threshold. Accordingly, changing the threshold will reduce costs for some sources, while increasing costs for other sources. Based on an analysis of reported emissions, the proposed threshold change will reduce industry fees paid to the Division by \$47,702 per year. Because the emissions from sources that are not currently reporting is unknown it is not possible to calculate

⁵ Permit cost savings were calculated using an average of 4 hours spent per permit, as determined by the time spent on permits processed due to the catch-all provisions in the Division's permit tracking project, multiplied by the Division billing rate of \$76.45 an hour.

the additional costs to sources that will be required to report for the first time under the new proposed threshold. Based on the relative prevalence of different emissions, however, the Division believes that there will be a small net savings to the regulated community.

Additionally, beyond the actual emission fees, the current reporting system is very complex resulting in numerous hours being spent by both the regulated community and Division staff in determining whether reporting is required. Simplifying the reporting system will eliminate the costs associated with this analysis.

Some stationary sources affected by the proposed revisions would benefit because they would no longer be required to report their non-criteria reportable pollutant emissions, thus saving filing and possibly annual fees. The revised threshold of 250 pounds per year preserves at least 96% of the Division's current inventory of non-criteria reportable pollutants. Other sources may have new costs related to having to report emissions that were previously below reporting thresholds, including filing and annual fees. This impact is unknown at this time because these sources are not currently subject to Colorado's reporting and permitting requirements. While EPA does not require States to report hazardous air pollutant emissions, EPA utilizes this data to annually populate the National Emissions Inventory. Accordingly, Colorado will continue to provide a robust set of data while also serving an important regulatory streamlining purpose.

3.2.3.3 Crude Oil Storage Tanks

Owners and operators of crude oil storage tanks may have new costs related to obtaining permits for previously permit-exempt equipment. There are minimal direct costs projected for the affected businesses and industrial sector associated with the removal of the crude oil storage tank permitting exemption. Stationary sources with crude oil storage tanks whose uncontrolled actual emissions exceed the minor source or operating permit thresholds would be required to obtain a permit. In 2008, the Commission removed the reporting exemption for crude oil storage tanks to improve the inventory of uncontrolled actual emissions. While the Division believes there are many crude oil storage tanks in Colorado, the Division's APEN inventory only identifies 64 crude oil storage tanks with a design capacity of 40,000 gallons or less in Colorado. Removal of the crude oil storage tank minor source permitting exemption would require these tanks to obtain minor source permits at a cost of approximately \$19,500.

3.2.3.4 Minor Source Permitting Correction

No practical impact is anticipated as a result of this revision, as the Division continues to implement the provision as was originally intended.

3.2.4 Probable Agency Costs

“The probable costs to the agency and to any other agency of the implementation and enforcement of the proposed rule and any anticipated effect on state revenues.”

The Division does not anticipate any negative effect on state revenues. Any potential Full Time Equivalent (“FTE”) personnel savings will be redirected to addressing the current permitting backlog. Any loss in permitting fees, will be offset by the processing of backlog permits. In

addition, the crude oil storage tank permitting exemption revisions will slightly increase the submission of permitting fees. Similarly, the Division anticipates the reduction in filing and annual fees due to the approximately 4% reduction in current non-criteria reportable pollutant reporting to be offset by the increased reporting and associated fees by stationary sources with non-criteria reportable pollutant emissions greater than 250 pounds per year.

3.2.4.1 Catch-all Provisions

The revisions to the catch-all provisions will reduce the administrative burden on both the Division and the regulated community. The Division estimated through the permit tracking project that the staffing of approximately 0.6 FTE would be saved due to the revisions. However, revising the catch-all provisions does not change the applicability or enforcement of the NSPS or NESHAP/MACT.

3.2.4.2 Non-criteria Reportable Pollutants

The revisions to the non-criteria reportable pollutant threshold establish a simplified, standard reporting threshold of 250 pounds per year for all non-criteria reportable pollutants. This eliminates the complicated matrix system and streamlines the process for sources, and for the Division, both in explaining the process to sources and reviewing reported emissions. The work associated with any increased reporting will be absorbed by existing Division staff or potentially offset by the approximately 4% reduction in current non-criteria reportable pollutant reporting.

3.2.4.3 Crude Oil Storage Tanks

The Division's APEN inventory currently identifies 64 crude oil storage tanks with a design capacity of 40,000 gallons or less. The work associated with permitting and inspecting these, and potentially more, sources will be absorbed by existing Division staff.

3.2.4.4 Minor Source Permitting Correction

There are no additional agency costs incurred as a result of this revision, as the Division continues to implement the provision as was originally intended.

3.2.5 Comparison to Inaction

“A comparison of the probable costs and benefits of the proposed rule to the probable costs and benefits of inaction.”

If the Commission does not adopt at least the proposed revisions to the catchall provisions, the Division would not recommend full adoption of NSPS OOOO. Further, absent adoption of the proposed revisions to the catchall provisions, the Division's permitting backlog will be negatively impacted. Finally, the public, regulated community, and other agencies will continue to experience the complexity and confusion of the APEN reporting thresholds and Appendix A de minimis levels applicability determinations. If the Commission does not adopt the proposed crude oil storage tank exemption revisions, a potentially significant source of emissions will continue to be exempt from permitting requirements. If the Commission does not make the minor source permitting correction, the provision will not align with the Commission's intent at the time of adoption nor the Division's current implementation of the provision. The purposes of the proposed revisions to Regulation 3 include allowing full adoption of NSPS OOOO,

streamlining and clarifying reporting and permitting, and requiring permits for a potentially significant source of emissions.

3.2.5.1 Catch-all Provisions

The revisions to the catch-all provisions reduce reporting and permitting costs. If the Commission does not adopt the proposed revisions, the regulated community and the Division will retain those reporting and permitting costs. Further, if the Commission adopts NSPS OOOO, and other NSPS and NESHAP/MACT similarly affecting very small sources, in full without removing the catch-all provisions, the increase in APEN reporting and minor source permitting would overwhelm both the Division and the regulated community.

3.2.5.2 Non-criteria Reportable Pollutants

The revisions to the non-criteria reportable pollutant thresholds may reduce costs for some sources and increase costs for other sources. However, all sources will benefit from the increased clarity of the de minimis reporting determination. If the Commission does not adopt the proposed revisions, the public, regulated community, and the Division will continue to deal with a complex and confusing reporting determination.

3.2.5.3 Crude Oil Storage Tanks

The costs of the proposed revisions to the crude oil storage tank permit exemptions include the costs to the regulated community of obtaining permits and the costs to the Division of permitting and inspecting subject tanks. Removing the permitting exemptions also increases the consistency of Colorado's regulations with NSPS OOOO by requiring these sources to also be subject to Colorado's notification, recordkeeping, and control requirements. If the Commission does not adopt the proposed crude oil storage tank exemption revisions, there will not be costs associated with permitting but a potentially significant source of emissions will continue to be exempt from permitting requirements.

3.2.5.4 Minor Source Permitting Correction

No costs are anticipated with the proposed revisions, as the Division will continue to implement the provision as was originally intended.

3.2.6 Less Costly Methods/Less Intrusive Methods

“A determination of whether there are less costly methods or less intrusive methods for achieving the purpose of the proposed rule.”

The Division does not believe that there are less costly or less intrusive methods to fully adopt NSPS OOOO than the Division's proposal.

3.2.6.1 Catchall Provisions

The Division believes that the revisions to the catch-all provisions are necessary to adopt NSPS OOOO, and other NSPS and NESHAP/MACT similarly affecting very small sources, due to the anticipated extensive number of APENs and minor source permit applications that would be required. Consider how the current catch-all provisions would apply if the Commission adopts MACT JJJJJ, which applies to a multitude of small boilers. Under the catch-all provisions,

every boiler providing electricity, steam, or hot water in a hotel, restaurant, laundry, medical center, research center, institution of higher education, or manufacturing, processing, mining, or refining facility would be required to file an APEN and obtain a minor source permit, even if the source had emissions less than the reporting and permitting thresholds. Other examples of rules similarly affecting very small sources include NSPS JJJJ, which applies to numerous stationary spark ignition internal combustion engines; MACT M, which applies to all perchloroethylene dry cleaning facilities; MACT HHHHHH, which applies to paint stripping and spray applications of greater than three motor vehicles or mobile equipment; and MACT SSSSSS, which applies to all glass manufacturing facilities. Under the current catch-all provisions, all of these facilities would require APENs and minor source permits, even if emissions are below the reporting and permitting thresholds.

If NSPS OOOO is adopted in full without the corresponding adoption of the proposed revisions to the catch-all provisions, the regulated community will be required to file APENs and obtain minor source permits for every NSPS OOOO affected facility. In turn, the Division's permitting backlog will likely grow and industry's ability to obtain timely permits will be negatively impacted. In comparison, if NSPS OOOO is adopted in full along with the proposed revisions to the catch-all provisions, only NSPS OOOO affected facilities with emissions greater than the reporting and minor source permitting thresholds will be required to report emissions and obtain minor source permits. This is currently how the partial adoption of NSPS OOOO is implemented. Thus, the Division does not believe there are less costly or intrusive methods than the proposed catch-all provisions revisions to reduce the administrative impact of full adoption of NSPS OOOO.

Similarly, the Division does not believe there are less costly or intrusive methods than the proposed catch-all provisions revisions to improve the efficiency of Colorado's reporting and permitting system for NSPS or NESHAP/MACT subject sources with emissions below the reporting and permitting thresholds, especially since these revisions will save costs for both the Division and the regulated community.

3.2.6.2 Appendix A

The purpose of the revisions to the non-criteria reportable pollutant thresholds is to simplify a complex and confusing reporting determination.

The Division cannot quantify the costs of unknown non-criteria reportable pollutants but considers the true cost savings of the proposed revision to the non-criteria reportable pollutant threshold the savings in time and effort of the public and regulated community in determining applicability under the revised Appendix A. While some sources non-criteria reportable pollutant reporting will increase, the Division does not believe there is a less costly or intrusive method to streamline the non-criteria reportable pollutant reporting determination while still maintaining a robust non-criteria reportable pollutant inventory.

3.2.6.3 Crude Oil Tank Permit Exemption

Requiring permits for crude oil storage tanks, a potentially significant source of emissions, cannot be accomplished in any less costly or less intrusive method. Further, some sources will

want enforceable permit limits on their crude oil storage tanks so as to be exempt from NSPS OOOO storage vessel requirements.

3.2.6.4 Minor Source Permitting Correction

There are no less costly or no less intrusive methods, as the Division will continue to implement the provision as was originally intended.

3.2.7 Alternative Methods

“A description of any alternative methods for achieving the purpose of the proposed rule that were seriously considered by the agency and the reasons why they were rejected in favor of the proposed rule.”

In addition to the Division’s proposal, various parties to the rulemaking have submitted different alternative proposals for the Commission to consider. Some of these proposals request that the Commission adopt additional requirements, increasing APEN reporting and permitting thresholds, as well as change how emissions are reported to the Division.

The Division considered revising the APEN and minor source permitting thresholds to further simplify and clarify APEN reporting and minor source permitting. However, the Division decided not to pursue revising the APEN and minor source permitting thresholds at this time, in order to avoid diverting focus from the important emission reductions associated with the proposed revisions to Regulation Number 7, and provide additional time to work with EPA on the potential development of a sufficient noninterference demonstration for such revisions.

Further, the Division considered alternative thresholds for the proposed revisions to the non-criteria reportable threshold. The Division selected the 250 pound per year threshold due to concerns about higher thresholds and the retention of approximately 96% of the Division’s current non-criteria reportable pollutant inventory under the proposed revision.

The Division did not consider any alternatives concerning the proposed revisions to the crude oil storage tank permitting exemptions or the minor source permitting correction.

3.2.8 Quantification of Data

“To the extent practicable, a quantification of the data used in the analysis; the analysis must take into account both short-term and long-term consequences.”

The Division quantified the short-term consequences and used them to project long-term consequences of the Regulation 3 proposal.

3.2.8.1 Catch-all Provisions

The Division tracked all pre-construction permits, which includes permits processed for point sources at both major stationary sources and minor sources, between mid-February and September, 2013. The permit tracking project indicates that 7% (167 of 2,355) of those permits

processed required permits because of the catch-all provision. In addition, the potentially eliminated emissions in comparison to statewide emissions are all much less than 1%, as illustrated in **Table 1** below.

Table 1: Emissions from Sources Potentially No Longer Requiring Permits due to the Catch-all Revisions (State-wide)

Pollutant	Uncontrolled actual emissions of potentially eliminated permits during tracking project (tpy, % of statewide emissions)	Uncontrolled actual emissions statewide⁶ (tpy)
CO	45 (0.05%)	99,929
NOx	110 (0.07%)	165,192
Total PM ⁷	32 (0.0004%)	7,385,720
SO2	0.2 (0.0002%)	115,715
VOC	24 (0.005%)	469,396
TOTAL	211.2 (0.003%)	8,235,952

Further, 4% (87 of 2,355) of the permits processed that required permits because of the catch-all provision are in the nonattainment area (“NAA”). The potentially eliminated emissions in comparison to NAA emissions are also much less than 1%, as illustrated in **Table 2** below.

Table 2: Emissions from Sources Potentially No Longer Requiring Permits due to the Catch-all Revisions (8-Hour Ozone NAA)

Pollutant	Uncontrolled actual emissions of potentially eliminated permits during tracking project in the NAA (tpy, % of NAA emissions)	NAA uncontrolled actual emissions⁸ (tpy)
CO	19 (0.1%)	19,110
NOx	90 (0.24%)	37,831
Total PM ⁹	15 (0.003%)	441,084
SO2	0.1 (0.0004%)	23,994
VOC	5 (0.004%)	140,463
TOTAL	129.1 (0.02%)	662,482

Importantly, these tables represent point source emissions, and do not include mobile source or area source emissions. Therefore, the percentage of emissions potentially eliminated from

⁶ January-November, 2013, total emissions.

⁷ Includes PM, PM10, and PM2.5.

⁸ January-November, 2013, total emissions.

⁹ Includes PM, PM10, and PM2.5.

permitting due to the removal of the catch-all provisions is even less, if the total emissions inventory, including point, mobile and area source emissions, were used.

The revisions to the catch-all provisions reduce costs to affected classes of persons, due to fewer sources being required to file APENs and obtain minor source permits. The Division's permit tracking project shows that 7% (167 of 2,355) of the permits processed between mid-February and September, 2013, were permitted due to the catch-all provision. The total hourly permit processing fees for these permits was approximately \$50,000¹⁰. This cost estimate does not include the time saved by the sources by no longer having to complete and submit an APEN or minor source permit application.

The environmental impacts of revising the catch-all provisions are minimal and no emissions increases are anticipated because these revisions will not exempt any source from complying with the requirements of an applicable NSPS or NESHAP/MACT. The Division's permit tracking project shows that the 7% of permits processed between mid-February 14, and September 30, 2013, accounted for approximately 0.03% of the total uncontrolled actual criteria pollutant emissions during the tracking project and 0.003% of statewide uncontrolled actual criteria pollutant emissions.¹¹

3.2.8.2 Appendix A

There are potential increased costs to the affected classes of persons associated with the revisions to Appendix A, however the full extent is unknown. This revision may increase the reporting requirements for a currently unknown quantity of Bin B and Bin C non-criteria reportable pollutants because the revised threshold is lower than the current lowest de minimis reporting thresholds of 500 and 1,000 pounds per year, respectively. This revision may also decrease the reporting requirements for some Bin A pollutants because the revised threshold is higher than the current lowest de minimis reporting threshold of 50 pounds per year. Sources will save emission fees of \$152.90 per ton of non-criteria reportable pollutant no longer required to report, not including the time saved by the sources due to not collecting the emissions data for and submitting APENs.

The environmental impacts of revising the catch-all provisions are minimal and no emissions increases are anticipated because these revisions will not exempt any source from complying with applicable requirements. In addition, the Division estimates that the proposed reporting thresholds of 250 pounds per year will retain at least 96% of the Division's current non-criteria reportable pollutant tracking for inventory purposes, which will continue to provide data to the EPA for the National Emissions Inventory, as well as to external customers such as environmental groups and the public. In addition, because the proposed reporting threshold is less than the current thresholds for many of the current scenarios, the revision will result in additional emissions of Bin B and Bin C pollutants being reported.

¹⁰ Permit cost savings were calculated using an average of 4 hours spent per permit, as determined by the time spent on permits processed due to the catch-all provisions in the Division's permit tracking project, multiplied by the Division billing rate of \$76.45 an hour.

¹¹ See the Division's January 29, 2014, CAA § 110(l) Noninterference Demonstration for a more detailed discussion of noninterference with the NAAQS.

3.2.8.3 Crude Oil Tank Permit Exemption

There are anticipated costs to the affected classes of persons associated with the removal of the crude oil storage tank permitting exemptions. The Division's APEN inventory currently only identifies 64 crude oil storage tanks with a design capacity of 40,000 gallons or less in Colorado. Removal of the crude oil storage tank minor source permitting exemption would require these tanks to obtain minor source permits at a cost of approximately \$19,500.

The emissions from crude oil storage tanks can be significant and permitting exemptions are meant to be limited to emission points with negligible impacts on air quality. The environmental impacts of revising the crude oil storage tank permitting exemptions may be significant, however, due to data limitations that impact is known.

The short term consequences of the proposed catch-all revisions include allowing the Commission to fully adopt NSPS OOOO. The long term consequences of the proposed catch-all revisions include potentially allowing the Commission to adopt other NSPS and NESHAP/MACT similarly affecting very small sources.

The short term consequences of the proposed revisions to the non-criteria reportable pollutant threshold include simplifying the non-criteria reportable pollutant reporting determinations for both the Division and the regulated community and reducing the Division's current non-criteria reportable pollutant inventory by approximately 4%. The long term consequences of the proposed revisions to the non-criteria reportable pollutant threshold are unknown.

The short-term consequences of the proposed crude oil storage tank permit exemptions include requiring existing crude oil storage tanks with a capacity of 40,000 gallons or less to obtain permits. The long term consequences of the proposed crude oil storage tank permit exemptions include requiring new crude oil storage tanks to obtain permits.

3.2.8.4 Minor Source Permitting Correction

Short- and long-term consequences of the proposed correction include aligning the provision with the Commission's original intent. No data was quantified relating to this revision.

3.3 Regulation Number 7

3.3.1 Discussion of Proposed Revisions

The Regulation 7 rulemaking package proposes revisions that expand existing oil and gas control requirements and establish additional monitoring, recordkeeping and reporting requirements. These proposed revisions include the following:

- 1) Enhancing the existing control program for petroleum storage tanks by:
 - a. Lowering the control requirement threshold for condensate storage tanks from 20 to 6 tons per year of uncontrolled actual volatile organic compound (VOC) emissions;

- b. Requiring controls for crude oil and produced water storage tanks with uncontrolled actual VOC emissions that are equal or greater than 6 tons per year; and
 - c. Expanding NAA requirements for tank controls during the first 90 days of production to the rest of the state;
- 2) Establishing requirements to ensure that emissions from controlled storage tanks are captured and routed to the control device;
- 3) Enhancing the existing control program for dehys by:
 - a. Increasing the control requirements from 90% to 95%;
 - b. Increasing designed destruction efficiency requirements from 95% to 98%;
 - c. Establishing more stringent requirements for individual dehys located in proximity to a building unit or designated outside activity area;
- 4) Establishing LDAR requirements for compressor stations and well production facilities, including requirements to reduce emissions from compressor seals and open ended lines consistent with current federal requirements;
- 5) Expanding the existing 8-hour ozone NAA requirements for auto-igniters on flare devices to the rest of the state;
- 6) Expanding the existing NAA requirements for low bleed pneumatic devices to the rest of the state and where feasible requiring no-bleed pneumatic devices; and
- 7) Requiring that the gas stream at newly constructed well production facilities either be connected to a pipeline or routed to a control device from the date of first production.

If adopted, these proposed revisions will result in substantial reduction of hydrocarbon emissions including volatile organic compounds (VOCs) and methane.

Several industry and environmental parties fully support the Division's proposed revisions to Regulation 7. Conversely, some parties request that the Commission adopt additional requirements that go beyond the Division's proposal, while other alternatives request that the Commission limit aspects of the Division's proposed revisions. See Section 3.3.7 of this Regulatory Analysis for details on the parties' alternative proposals.

3.3.2 Class of Persons Affected

"A description of the classes of persons who will be affected by the proposed rule, including classes that will bear the costs of the proposed rule and classes that will benefit from the proposed rule."

The proposal affects the oil and gas industry and supporting businesses in Colorado. Further, the proposal broadly benefits all persons in Colorado, especially those who live and work in the proximity of oil and gas operations. Companies that will bear the costs of this rule change include the oil and gas companies operating, drilling, recompleting or otherwise stimulating wells in the NAA, as well as well production facilities, compressor stations and dehys. Revisions to Regulation 7 may require installation of controls to reduce hydrocarbon emissions from storage tanks, dehys, and separators on newly constructed, hydraulically fractured or recompleted wells. Typically flares are used as control equipment, but vapor recovery units ("VRUs") and other

Division-approved pollution prevention devices may be used. Use of best management practices or controls may also be required for well maintenance and liquids unloading activities. Regulation 7 revisions may also require installation of auto-igniters on combustion devices and installation of low- or no-bleed pneumatic controllers. In addition, compressor stations and well production facilities may be required to monitor components for emissions and repair leaks. Owners and operators of well production facilities or compressor stations that include compressor seals and open-ended lines may have to comply with additional work practice standards.

The proposed Regulation 7 will benefit those companies that manufacture and/or distribute flare control devices, VRUs, auto-igniters or low- and no-bleed pneumatic controllers. Companies that manufacture hydrocarbon monitoring equipment, including infra-red (“IR”) cameras, photo-ionization detectors, flame ionization detectors and other Division-approved monitoring methods, as well as those companies that provide or support monitoring services may also benefit from these proposed revisions.

Given that VOCs are precursors to ozone, the citizens in the NAA will benefit from the proposed rule through reduced ozone precursor emissions. State-wide, persons living or working in proximity to storage tanks, dehyds, wells, well production facilities or compressor stations will benefit from reduced air emissions. See Section 3.3.3 of this Regulatory Analysis for a more comprehensive review of public health impacts.

Thus, all persons in the State benefit from the proposed revisions.

3.3.3 Quantitative and Qualitative Impacts

“To the extent practicable, a description of the probable quantitative and qualitative impact of the proposed rule, economic or otherwise, upon affected classes of persons.”

The proposed changes to Regulation Number 7 are projected to result in substantial reductions of hydrocarbon emissions (including both VOCs and methane/ethane) from the oil and gas industry. The Division estimates approximately 93,500 tons per year VOC, or 257 tons per day, and approximately 64,000 tons per year methane/ethane will be reduced.

Qualitative impacts of this Regulation 7 proposal are closely related to Colorado’s air quality and economy. During the past ten years, Colorado has been a leader in developing and implementing requirements to reduce air emissions from the oil and gas sector. As a result of these efforts, Colorado now has in place a series of cost-effective requirements that significantly reduce air emissions from Colorado oil and gas facilities. Despite this success, however, the tremendous growth of oil and gas production in Colorado continues to threaten the air quality gains that we have achieved. Since 2004 gas production in Colorado has increased by 50% while oil production has more than doubled. While this growth has provided important economic benefits for Colorado, increased air emissions can have a negative impact on Colorado’s public health and environment.

Specifically, VOC emissions contribute to the formation of ground level ozone. Ozone is photochemical oxidant and known respiratory irritant. Ground level ozone is a secondary pollutant produced through the reaction of VOCs, nitrogen oxides and sunlight. Elevated levels of ground level ozone have been linked to a variety of adverse health effects including decreased lung function, increased respiratory symptoms, serious indicators of respiratory morbidity including emergency visits and hospital admissions, as well as total non-accidental and cardio-respiratory mortality. According to EPA, ground-level ozone also damages vegetation and ecosystems. It leads to reduced agricultural crop and commercial forest yields, reduced growth and survivability of tree seedlings, and increased susceptibility to diseases, pests and other stresses such as harsh weather. In the United States alone, ground-level ozone is responsible for an estimated \$500 million in reduced crop production each year. Ground-level ozone also damages the foliage of trees and other plants, affecting the landscape of cities, national parks and forests, and recreation areas.¹²

The U.S. EPA has set the current National Ambient Air Quality Standards (“NAAQS”) for ground level ozone at 75 parts per billion (ppb) averaged over an 8-hour period. Based on a review of the then current health literature, the Clean Air Scientific Advisory Committee concluded in 2008 that the 75 ppb standard was not sufficiently protective of public health, and recommended that the standard be set at between 60 ppb and 70 ppb. EPA is in the process of considering whether to lower the ozone standard.

Currently, the Denver Metro/North Front Range area is out of attainment with federal health-based ground level ozone standards. This includes much of the Denver/Julesberg oil field. Other areas of the state have also experienced elevated ozone levels recently, with one monitor in Western Colorado showing concentrations above 75 ppb and a number of other monitors showing levels between 60 ppb and 75 ppb.

Addressing oil and gas emissions is a critical component of Colorado’s efforts to lower ozone levels since this sector represents the largest source of VOC emissions in the state. Based on the most recent inventory (2011), 54% of the anthropogenic VOC emissions in the state come from the oil and gas sector, which is roughly triple the amount of emissions from the next largest source. Moreover, because of the ongoing growth in the oil and gas industry and the projected decline in VOC emissions from other sectors, the share of VOC emissions attributable to the oil and gas sector will likely increase over the foreseeable future. The proposed emission reduction strategies will further enhance existing public health and environment protections on both a local and regional scale.

In addition to VOC emissions, oil and gas operations are a large source of methane. Methane is a potent greenhouse gas, which contributes to global climate change. In addition to reducing VOCs that contribute to regional ozone pollution, the Division’s proposed strategies will reduce methane, and thereby play a role in Colorado’s overall efforts to reduce greenhouse gas emissions. Finally, the proposed strategies will reduce the exposure of people that live and work

¹² See EPA website, “Ozone – Good Up High Bad Nearby.” <http://www.epa.gov/oar/aqps/gooduphigh/bad.html>. February 11, 2014.

near oil and gas production sites to VOC emissions. Methane is also a valuable natural resource (natural gas), and reducing leaks will benefit Colorado's environment and economy.

The Division assesses the direct and indirect costs to the regulated community for each of the proposed strategies in Regulation Number 7 in Section 3.3.8 of this Regulatory Analysis. Equipment costs, labor costs, maintenance costs, supervision costs, travel costs, and costs associated with recordkeeping and reporting are all evaluated. The Division estimates that the total annual costs to the regulated community as a result of the proposed strategies will be approximately \$59.2 million. Further, the proposed strategies are expected to result in the capture of additional product worth approximately \$16.8 million, for a total net cost of \$42.4 per year. In addition to these direct costs, implementation of the proposed strategies could result in the shut-in of certain marginally producing wells, resulting in indirect costs in the form of lost revenues to oil and gas companies, loss of jobs associated with these facilities, lost royalty payments, and lost severance taxes. Based on available information the Division cannot reasonably calculate the amount of additional oil and gas that would be shut-in due to the proposed rules, but believes that the amount is likely to be very small due to the low costs attributable to small, marginally producing facilities.¹³ An analysis by an economist hired by certain industry parties has suggested that these indirect costs could be quite large.¹⁴ This information will be considered by the Commission as part of the rulemaking hearing.

The Division recognizes that the oil and gas industry plays an important role in Colorado's economy in the evaluation of qualitative impacts of the Regulation 7 proposal. The industry is a significant employer of highly skilled and well-paid employees. The industry generates large revenues and pays significant taxes in the state. It produces valuable domestic resources that help keep prices low while adding to national stability and security. At the same time, emissions from the oil and gas industry represent a significant portion of the total VOC emissions both in the NAA and throughout the rest of the state. The Division's proposal is intended to achieve significant reductions in air emissions without imposing unreasonable costs that could stifle economic activity.

As discussed above, the Division's proposal is projected to result in a net annual cost to the industry of approximately \$42.4 million. As with any increase in costs, the costs associated with the Division's proposal could have some adverse impact on economic activity associated with the oil and gas industry in Colorado. However, over the past decade Colorado's oil and gas industry has experienced unprecedented growth, even as Colorado has enacted regulatory measures to ensure that development continues in a protective and responsible manner. Moreover, given the relative size of the costs of the current proposal to the overall size of the industry, the total impact of these costs will likely be minimal. In 2012, for example, oil and gas producers in Colorado sold 48,450,717 barrels of oil and 1,661,073,176 MCF of natural gas.

Based on the current price of oil, \$96 per barrel, and assuming a price for natural gas of

¹³ See discussion in Section 3.3.8 of this Regulatory Analysis.

¹⁴ See Attached Exhibit A.

\$3.5/MCF¹⁵, annual revenue from the sale of oil and gas in Colorado based on 2012 production levels is approximately \$10.5 billion. Accordingly, the net cost of the Division's proposal is approximately 0.4% of the annual revenues. Given this small percentage, the Division's proposal is unlikely to have any appreciable impact on the economic competitiveness of the industry as a whole. This conclusion is bolstered by the fact that several of the largest oil and gas companies in the state (Anadarko Petroleum Corp., Noble Energy, Inc., Encana Oil and Gas USA, and DCP Midstream) fully support the Division's proposed revisions. Collectively, the Division estimates that these companies will bear approximately 75% of the total annual cost of the proposed rules.

While it is unlikely that the costs associated with the proposed revisions will have any meaningfully adverse impacts on the competitiveness of the industry as a whole in Colorado, the costs could incrementally add to the current costs associated with operating marginally producing wells. This could potentially lead to some wells being shut in and the resultant economic consequences of these shut-ins including lost production revenue, lost royalties, lost severance taxes and potentially lost jobs. To mitigate against this possibility, the Division's has crafted a tiered proposal that triggers requirements based on emission thresholds that are directly tied to production. Based on this, the truly small facilities are subject to less requirements and less costs; for example, only a one-time instrument-based leak inspection, which the Division estimates will cost approximately \$712.

Finally, it does not appear that the costs associated with the Division's proposal will have any meaningful negative impact on the general public or small businesses that purchase natural gas and other petroleum products. Oil and natural gas are sold on international and national markets, making it extremely unlikely that any increase in production costs in Colorado will be reflected in prices for Colorado consumers.

3.3.4 Probable Agency Costs

"The probable costs to the agency and to any other agency of the implementation and enforcement of the proposed rule and any anticipated effect on state revenues."

The Division will largely implement the provisions of its proposal through its oil and gas inspection team. This team currently consists of nine full time inspectors and four term limited inspectors. In 2012, in response to the growth in the oil and gas industry in Colorado, the legislature approved increasing the size of the inspection team from six inspectors to nine. In 2013, the legislature appropriated additional funds to hire four term limited inspectors to conduct IR camera inspections at well production facilities in Colorado. The term for these positions runs through June of 2015, but could be extended by the legislature if warranted. The additional inspectors provided during the 2012 and 2013 legislative sessions has significantly expanded the capabilities of the oil and gas inspection team, which will further enable the Division to implement and enforce the proposed requirements if the Commission chooses to adopt the Division's proposal. The total projected annual cost to the Division for the oil and gas inspection

¹⁵ The Division assumed a price per MCF of \$3.50 throughout its analysis; however, natural gas prices are currently around \$5 per MCF, suggesting that the Division has underestimated the value of gas saved by the proposal.

team in fiscal year 2013-14 is \$1,305,304, which includes salary costs, fringe benefits, operating costs (including vehicles, field equipment, and office equipment), travel training and indirect costs.

The Division does not anticipate state revenues to be affected because the proposal does not assess any additional emissions reporting or permitting fees beyond those that already apply. However, state revenues could potentially be affected by implementation of the proposed strategies, in that they could potentially result in the shut-in of a few marginally producing wells, resulting in indirect costs in the form of lost revenues to oil and gas companies, loss of jobs associated with these facilities, lost royalty payments, and lost severance taxes. Based on available information the Division cannot reasonably calculate the amount of oil and gas that could be shut-in due to the proposed rules, but believes that the amount is likely to be very small due to the low costs attributable to small, marginally producing facilities.

3.3.5 Comparison to Inaction

“A comparison of the probable costs and benefits of the proposed rule to the probable costs and benefits of inaction.”

The Division estimates the proposed strategies will reduce volatile organic compound (VOC) emissions by 93,500 tons per year, and methane/ethane emissions by 64,000 tons per year. The Division conservatively estimates that the annual net costs to industry of the Division’s proposal will be \$42.4 million per year. This translates to approximately \$453 per ton of VOC reduced. Costs and benefits of the proposed Regulation 7 revisions are detailed in Section 3.3.8.

Conversely, inaction would mean that the above emissions reductions are not realized, that the associated captured methane (natural gas), a valuable natural resource, is lost to the ambient air and that the estimated cost savings in captured product that can be sold at a profit is not realized. Further, emissions from this sector are projected to grow substantially, especially in shale gas/oil development.¹⁶

The forecast growth in shale gas/oil development will result in increased emissions of VOC and other hydrocarbons including greenhouse gases, unless additional controls are implemented. This could result in increases in ozone formation and the development of additional State Implementation Plan requirements to meet current and future NAAQS requirements. According to EPA, attaining the current ozone standard throughout the nation will result in between \$6.9 billion and \$18 billion in annual health benefits. For lower standards the health benefits are even greater. For example, EPA projects that achieve a 70 ppb standard will result in between \$13 billion and \$37 billion in annual health benefits, and for a 65 ppb standard the benefits will increase to between \$22 billion and \$61 billion per year. EPA does not report these health benefits by state, but since the population of the Denver Metropolitan Area/North Front Range NAA accounts for approximately 2.5% of the total national population living in areas that are in

¹⁶ U. S. Energy Information Administration. “Annual Energy Outlook 2013”. April 15-May 2, 2013.

violation of the current NAAQS, the health benefits attributable to Colorado are likely to be substantial.

The proposed rules will also produce substantial benefits associated with reducing greenhouse gases. As part of this rulemaking the Environmental Defense Fund has engaged an expert to analyze the benefits of the rulemaking based on the social cost of carbon. Based on this analysis, EDF projects that the total annual benefit from the projected methane reductions is between \$104 million and \$318 million in 2016 and between \$132 million and \$404 million in 2025.¹⁷

In addition to the benefits associated with reductions of VOCs and methane, the proposed rules will produce additional economic benefits in the form increased product capture and the creation of new jobs associated with the implementation of the new requirements.

3.3.6 Less Costly Methods/Less Intrusive Methods

“A determination of whether there are less costly methods or less intrusive methods for achieving the purpose of the proposed rule.”

In 2004, 2006 and again in 2008, the Commission established oil and gas industry specific emissions control requirements in an effort to reduce VOC emissions in the 8-hour ozone NAA. The tremendous growth of oil and gas production in Colorado and the associated emissions continue to threaten the air quality gains that have been achieved. Since 2004 gas production in Colorado has increased by 50% while oil production has more than doubled. Since then, the oil and gas industry has grown significantly (more than predicted), and changes in drilling technologies and other advancements have further supported growth in this industry. The oil and gas industry continues to be the largest VOC emitter in Colorado (illustrated in Figure 1, below).

Several industry alternative proposals identify less costly and/or less intrusive methods to reduce emissions (see Section 3.3.7 of this Regulatory Analysis). The Division made several clarifications based on these alternatives, but did not substantially revise the Division’s Regulation 7 proposal. The Division believes the Regulation 7 proposal secures more emissions reductions than those alternatives, and those additional emission reductions are cost effective. Moreover, several parties have proposed more costly and/or more intrusive methods to reduce emissions. The Division believes that its proposal strikes a proper balance and achieves substantial emissions reductions in a cost effective manner.

¹⁷ See Attached Exhibit B.

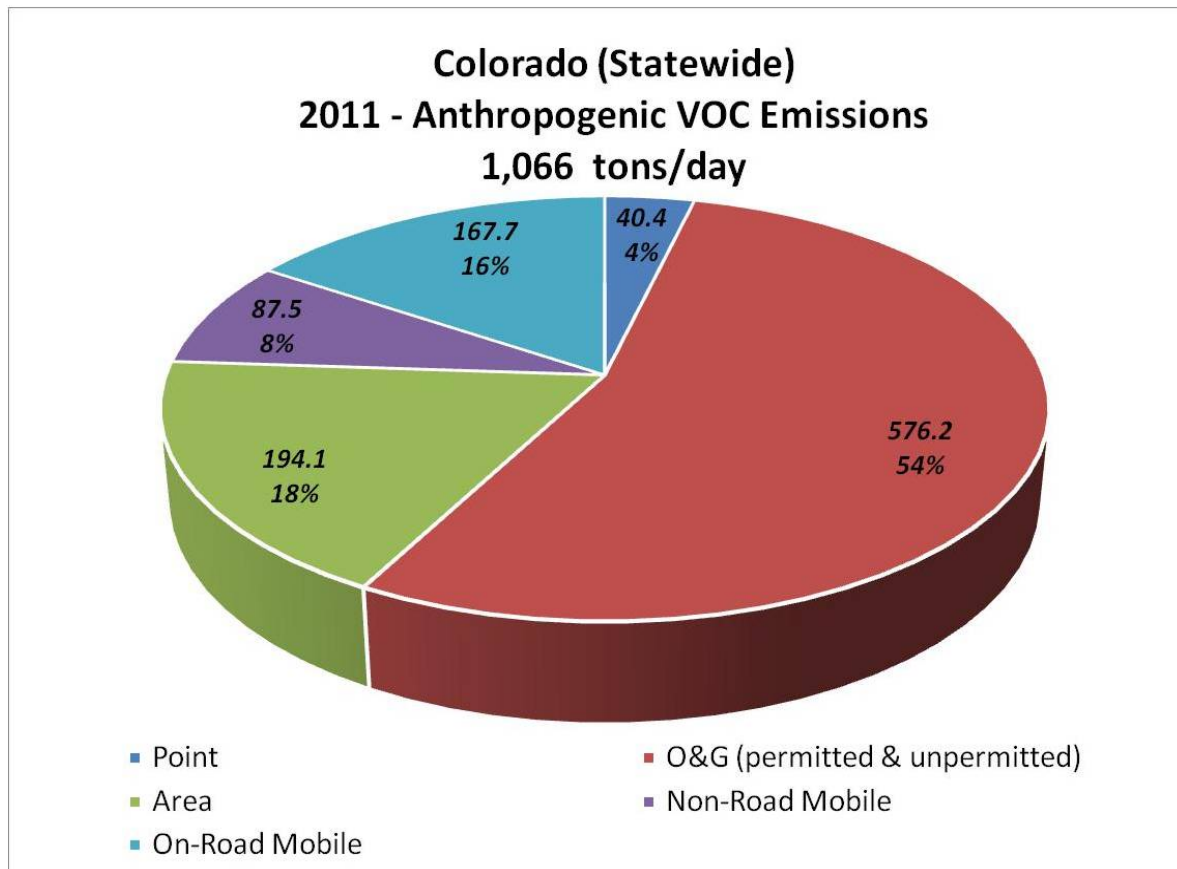


Figure 1 - Colorado Statewide Anthropogenic VOC Emissions (2011)

3.3.7 Alternative Methods

“A description of any alternative methods for achieving the purpose of the proposed rule that were seriously considered by the agency and the reasons why they were rejected in favor of the proposed rule.”

In addition to the Division’s proposal, various parties to the rulemaking have submitted 6 different alternative proposals for the Commission to consider. Some of these proposals request that the Commission adopt additional requirements that go beyond the Division’s proposal, while other alternatives request that the Commission limit aspects of the Division’s proposed revisions. In some cases, the parties submitting the proposals included analyses estimating the costs and benefits associated with their proposals. Copies of each of these proposals along with any economic impact analysis that the parties submitted identifying the projected costs and benefits of their particular proposals are attached to this Regulatory Analysis as exhibits. Upon evaluation of these proposals, and other parties’ comments, the Division made several clarifications to but did not substantially revise the Division’s Regulation 7 proposal. The Division believes the Regulation 7 proposal strikes an appropriate balance between the various alternatives.

The section below identifies each of the submitted proposals, discusses how the proposals differ from the Division's proposal, and addresses the projected costs and benefits of each proposal.¹⁸

3.3.7.1 Joint Industry Work Group

A collection of oil and gas companies and industry trade groups have submitted an alternative proposal seeking to limit the requirements set forth in the Division's proposal.¹⁹ Specifically, the Joint Industry Work Group request that the Commission limit the Division's proposal in the following respects: 1) restrict all proposed requirements to the Denver Metropolitan Area/North Front Range 8-hour ozone NAA; 2) reduce the required frequency proposed for leak inspection and repair; 3) eliminate the proposed requirements for dehydrators; 4) limit proposed requirements for compressor seals and open-ended lines to compressor stations; and 5) eliminate proposed requirements related to well maintenance and liquids unloading. In addition to these proposed limitations, the Joint Industry Work Group have proposed a number of additional changes, which could have some minimal additional impacts on the costs and benefits of the proposal.

Since the Joint Industry Group did not submit an economic analysis detailing the projected costs and benefits of their alternative proposal,²⁰ the Division has conducted an analysis of the Joint Industry Work Group alternative proposal utilizing the same methodologies and assumptions detailed in Section 3.3.8 of this Regulatory Analysis. Based on this analysis, the Division estimates that the Joint Industry Work Group alternative proposal would have a net cost²¹ to the regulated community of approximately \$32.2 million, and would reduce emissions of VOCs by 56,525 tons per year and methane/ethane by 33,058 tons per year. The decrease in net costs should have some positive impact on the indirect costs associated with potential well shut-ins, but the Division is unable to reasonably calculate this impact. The decrease in costs relative to the Division's proposal includes a decrease in the number of facility inspections, which would result in fewer new inspector jobs attributable to the proposal. Finally, because the Joint Industry Work Group proposal would result in less VOC and methane emission reductions, the economic benefits associated with these reductions discussed in Section 3.3.8 of this Regulatory Analysis would be reduced.

¹⁸ In instances where a party submitted an analysis of the costs and benefits associated with their proposal such analysis is attached. Where parties submitted proposal without an analysis of their own proposal the Division has endeavored to analyze the costs and benefits of these proposals using the same methodologies used to analyze the costs and benefits of the Division's proposal.

¹⁹ A copy of this alternative proposal is attached to this Regulatory Analysis as Exhibit C.

²⁰ The group did submit an analysis of the Division's proposal showing substantially higher costs than reflected in the Division's analysis. A copy of this analysis is attached hereto as Exhibit A. It should be noted that while the Joint Industry Work Group predicts much higher costs from the Division's proposals, Anadarko Petroleum Corporation, Noble Energy, Inc. and Encana Oil and Gas USA have submitted information during the rulemaking supporting the reasonableness of the Division's cost and benefit calculations. Submissions from these companies can be found at the following link:

<ftp://ft.dphe.state.co.us/apc/aqcc/REBUTTAL%20STATEMENTS,%20EXHIBITS%20%26%20ALT%20PROPOSAL%20REVISIONS/>

²¹ Net cost reflects the cost of implementing the proposed strategy less the value of the additional product captured as a result of the proposed strategies.

3.3.7.2 WPX Energy

WPX is the largest natural gas producer in the state. In the current rulemaking WPX has offered an alternative proposal that would decrease the total number of leak inspections by allowing well production facilities with low leak rates during two consecutive inspections to reduce inspection frequency from monthly to quarterly, or from quarterly to annually depending on the size of the facility.²² While it is difficult to predict in advance how many facilities would be able to take advantage of this reduced inspection rate, for the purposes of this Regulatory Analysis the Division assumes that one half of the facilities would be able to utilize the reduced frequency. Based on this assumption, adoption of WPX's alternative proposal would reduce the total net annual cost of the proposed revisions from approximately \$42.4 million to approximately \$36.8 million. This change would also decrease the amount of emission reductions from the Division's proposal by 1,845 tons per year of VOC and 2,757 tons per year of methane/ethane.

The decrease in net costs should have some positive impact on the indirect costs associated with potential well shut-ins, but the Division is unable to reasonably calculate this impact. Given the relatively small difference in net costs between the two proposals, any positive impact should be fairly small. The decrease in costs relative to the Division's proposal includes a decrease in the number of facility inspections, which would result in fewer new inspector jobs attributable to the proposal. Based on the number of inspection hours for each proposal, the number of new inspector jobs would decrease. Finally, because the WPX proposal would result in less VOC and methane emission reductions, the economic benefits associated with these reductions discussed in Section 3.3.8 of this Regulatory Analysis would be reduced.

3.3.7.3 Conservation Groups

As part of the rulemaking a number of conservation groups have submitted an alternative proposal requiring additional leak detection inspections for well production facilities and compressor stations relative to the Division's proposal. In addition, the Conservation Groups' alternative proposal increases the number of pneumatic devices that would need to be retrofitted. A copy of the Conservation Groups' alternative proposal is attached as Exhibit D. Additionally, their analysis of the costs and benefits associated with their alternative proposal is attached as Exhibit E.

3.3.7.4 Local Community Organizations

A group of local community organizations have submitted an alternative proposal aimed at increasing the stringency of the Division's proposal for facilities that are located within 1,320 feet of a building unit or designated outdoor activity area. Specifically, for such facilities the Local Community Organizations' alternative proposal would decrease the threshold for controls from petroleum storage tanks from 6 tons per year (as proposed by the Division) to two tons per year. Additionally, facilities located within 1,320 feet of these designated areas would be subject to a more stringent leak inspection schedule. Copies of the Local Community Organizations'

²² In addition to this change, WPX has proposed a limited number of additional changes and clarifications that do not impact the cost and benefit calculations conducted for the Division's proposal. A copy of WPX's alternative proposal is attached as Exhibit F.

alternative proposal and their assessment of costs and emission reduction benefits are attached as Exhibits G and H.

3.3.7.5 Local Government Coalition

The Local Government Coalition consists of a number of county and city governments including Adams County, Boulder County, La Plata County, Pitkin County and San Miguel County, Fort Collins, the City of Boulder, and the City and County of Denver. In their alternative proposal, the Local Government Coalition seeks to increase the number of leak detection inspections for compressor stations and well production facilities relative to the Division's proposal. The Local Government Coalition also seeks to require that well production facilities be tied in to a gas gathering line within 90 days after the date of first production, unless the Division approves an extension of this deadline. Copies of the Local Government Coalition's alternative proposal and documents assessing the costs and benefits of that proposal are attached hereto as Exhibits I through M.

3.3.7.6 Worldwide Liquid Solutions, LLC

Worldwide Liquid Solutions (WLS) is a manufacturer of emission reduction technology designed to control VOC emissions from petroleum storage tanks. According to WLS, their emission reduction technology cannot control methane and ethane and therefore cannot meet the control standards for tanks reflected in the Division proposal. To address this, WLS has submitted an alternative proposal that would only require reductions of VOCs from tanks and not methane/ethane. As an alternative to their alternative, WLS has proposed rejecting all of the proposed changes to Regulation No. 7 set forth in the Division's proposal. Copies of WLS' alternative proposal and their assessment of costs and emission reduction benefits are attached as Exhibits N and O.

3.3.8 Quantification of Data

"To the extent practicable, a quantification of the data used in the analysis; the analysis must take into account both short-term and long-term consequences."

As set forth below, the Division has assessed the direct and indirect costs to the regulated community for each of the proposed strategies in Regulation Number 7. The Division estimates revisions to Regulation 7 will reduce VOC emissions by 93,500 tons per year, and methane/ethane emissions by 64,000 tons per year. The Division conservatively estimates that the annual net costs to industry of the Division's proposal will be \$42.4 million per year. This translates to approximately \$453 per ton of VOC reduced, which is very reasonable when compared to other air pollution reduction strategies adopted by the Colorado Commission and the EPA. The Division estimates that the total annual costs to the regulated community as a result of the proposed strategies will be approximately \$59.2 million. Further, the proposed strategies are expected to result in the capture of additional product worth approximately \$16.8 million, for a total net cost of \$42.4 million per year. In addition to these direct costs, implementation of the proposed strategies could potentially result in the shut-in of certain marginally producing wells, resulting in indirect

costs in the form of lost revenues to oil and gas companies, loss of jobs associated with these facilities, lost royalty payments, and lost severance taxes. Based on available information the Division cannot reasonably calculate the amount of oil and gas that could be shut-in due to the proposed rules, but believes that the amount is likely to be very small due to the low costs attributable to small, marginally producing facilities. To mitigate against this possibility, the Division's has crafted a tiered proposal that triggers requirements based on emission thresholds that are directly tied to production. Based on this, the truly small facilities are subject to less requirements and less costs; for example, only a one-time instrument-based leak inspection, which the Division estimates will cost approximately \$712. An analysis by an economist hired by certain industry parties has suggested that these indirect costs could be quite large.²³ This information will be considered by the Commission as part of the rulemaking hearing.

The detailed discussions below largely focus on short-term consequences of the proposal. Long term consequences potentially include having to establish greater and potentially more extreme control measures in the future to address the current mass of emissions and anticipated growth in emissions. The oil and gas industry is expected to continue to grow significantly, especially in shale gas/oil development.²⁴

This continued growth in shale gas/oil development will result in increased emissions of VOC and other hydrocarbons including methane and ethane, unless additional controls are implemented. This could result in increases in ozone formation and additional State Implementation Plan requirements to meet current and future NAAQS requirements. According to EPA, attaining the current ozone standard throughout the nation will result in between \$6.9 billion and \$18 billion in annual health benefits. For lower standards the health benefits are even greater. For example, EPA projects that achieving a 70 ppb standard will result in between \$13 billion and \$37 billion in annual health benefits, and for a 65 ppb standard the benefits will increase to between \$22 billion and \$61 billion per year. EPA does not report these health benefits by state, but since the population of the Denver Metropolitan Area/North Front Range NAA accounts for approximately 2.5% of the total national population living in areas that are in violation of the current NAAQS, the health benefits attributable to Colorado are likely to be substantial.

3.3.8.1 Control Requirements for Petroleum Storage Tanks

Commencing in 2004 the Commission has adopted a series of requirements aimed at reducing emissions from petroleum storage tanks at well production facilities, compressor stations and gas processing plants. Currently, condensate tanks with uncontrolled actual emissions of 20 tons per year or greater of VOC must be equipped with a control device that has a control efficiency of at least 95%. Additionally, with certain exceptions, operators in the NAA must achieve a 90% system-wide reduction of VOC emissions from condensate tanks during the period from May 1 through September 30, and 70% during the period from October 1 through April 30. These current requirements only apply to tanks that store condensate, which is defined in the Commission's Common Provisions regulation as "hydrocarbon liquids . . . with an API gravity

²³ See Attached Exhibit A.

²⁴ U. S. Energy Information Administration. "Annual Energy Outlook 2013". April 15-May 2, 2013.

of 40 degrees or greater.” While most of the petroleum liquid produced in Colorado qualifies as condensate, there are heavier hydrocarbon liquids, typically referred to as crude oil, with an API gravity below 40 degrees that are not subject to the current control requirements. Additionally, there are a number of high volume produced water tanks that have VOC emissions above 6 tons per year that are not currently regulated under the existing requirements.

While Colorado has achieved considerable success in controlling emissions from condensate tanks since 2004, petroleum storage tanks at oil and gas production and midstream facilities continue to be the most significant source of VOC emissions from this sector. To address this emission source the Division is proposing the following strategies: 1) reducing the control threshold from 20 tons per year VOC to 6 tons per year; 2) eliminating the distinction between condensate and other liquids and requiring controls strictly based on emission levels; and 3) extending the current requirement that all condensate tanks in the NAA be controlled during the first 90 days of production to storage tanks throughout the state. In order to meet each of these three strategies, the Division assumes that owners and operators will equip tanks with enclosed flares, as is the typical practice under the existing tank control requirements. The estimated costs associated with installing and maintaining an enclosed flare are set forth in subsection 3.3.8.1.1 of this Regulatory Analysis. Utilizing the calculated flare costs, the estimated costs and benefits for each of the three tank control strategies are discussed in subsections 3.3.8.1.2 – 3.3.8.1.4 of this Regulatory Analysis.

3.3.8.1.1 General Cost Estimates for Flares

The estimated cost for a flare control device is based on identified costs from a 2008 oil and gas cost study²⁵ adjusted for inflation. Based on this data, the estimated annualized cost of a flare control device with auto-igniter²⁶ is about \$6,287.²⁷

²⁵ See “Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination,” Lesair Environmental, Inc., June 2008. Information from this study was previously submitted to the Commission as part of the 2008 Ozone Action Plan process. For reference or background purposes, the Division has cited herein certain information that has been submitted to the Commission as part of the rulemaking; however, it is not necessarily included with this Regulatory Analysis as an exhibit.

²⁶ Currently only flares in the NAA are required to have auto-igniters. Under the current proposal, the auto-igniter requirement would be extended statewide. For the purposes of this cost analysis, it is assumed that auto-igniters will be required statewide. The cost and benefits associated with equipping existing flares outside the non-attainment with auto-igniters are discussed below in Section 3.3.8.1.7.

²⁷ Certain parties to the rulemaking have asserted that the actual cost per combustion device is higher based on EPA’s cost analysis conducted in accordance with NSPS OOOO. Based on a review of EPA’s analysis it appears that additional costs were included for surveillance systems that are not applicable to the proposed rule. Additionally, unlike the analysis in NSPS OOOO, the costs that the Division has identified are based on a Colorado specific cost analysis.

Table 1: Flare Control Device with Auto Igniter – Annualized Cost Analysis*

Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
Flare	\$18,169			
Freight/Engineering		\$1,648		
Flare Installation		\$6,980		
Auto Igniter	\$1,648			
Pilot Fuel**			\$768	
Maintenance			\$2,197	
Subtotal Costs	\$19,817	\$8,628	\$2,965	
Annualized Costs***	\$2,747	\$575	\$2,965	\$6,287

*Control cost evaluation based on 2008 Ozone Rulemaking cost survey and producer data. Control device costs were developed based on an oil and gas cost study and information submitted by industry in 2008. However, those costs were escalated by 9.85% to reflect CPI-U increases that have occurred since 2008.²⁸

** Pilot fuel costs \$3.41/MMBtu (Henry Hub Spot Price - Aug. 2013)

*** Annualized over 15 years at 5% ROR

3.3.8.1.2 Lowering Statewide Condensate Tank Control Threshold (from 20 tpy to 6 tpy)

The Division is proposing to lower the uncontrolled VOC emission control threshold from 20 tpy down to 6 tpy on condensate storage tanks statewide. Based on an analysis of the Air Pollution Emissions Notice (APEN) database, the Division estimates that statewide there are 588 uncontrolled condensate tank batteries with VOC emissions over six tons per year. Of these 588 tanks, 396 are outside the NAA and the remaining 192 are within the current NAA.

Table 2: Condensate Tank Battery Analysis

Tank Battery Type	Ozone NAA [count]	Outside NAA [count]	Cancelled Tanks [count]	Total Statewide Tanks [count]
Controlled Tanks	4,971	490		5,461
Uncontrolled Tanks	1,451	1,132	36	2,619
All Tanks	6,422	1,622	36	8,080
Uncontrolled Tanks ($\geq$ 6 tpy)	192	396		588

Based on the reported uncontrolled actual VOC emissions for these 588 tanks, and assuming both that 75% of the VOC emissions are captured and sent to the flare,²⁹ and that the flare has a 95% destruction efficiency, the total VOC emission reduction associated with lowering the condensate tank threshold statewide is 5,162 tons per year.

²⁸ It has been suggested that the Division should have used the Producer Price Index to calculate an escalation from 2008 to 2013 costs. From 2008 to 2013, however, the Producer Price Index for the oil and gas field equipment sector grew at a slower rate than the CPI. Accordingly, the Division's analysis may actually overstate the increase in cost from 2008 to 2013.

²⁹ The costs and benefits associated with improving the capture percentage for controlled storage tanks are discussed below in Section 3.3.8.1.5.

Table 3: Condensate Tank Battery Emissions Analysis for Lowering Statewide Threshold			
Tank Battery Type	Uncontrolled VOC Emissions [tons/year]	Controlled VOC Emissions [tons/year]	VOC Emission Reduction [tons/year]
NAA Uncontrolled Tanks (≥ 6 tpy)	2,355	677*	1,678
Outside NAA Uncontrolled Tanks (≥ 6 tpy)	4,890	1,406*	3,484
Totals:	7,245	2,083	5,162

*Emission reduction estimated by accounting for 75% capture and 95% destruction efficiency.

The annualized cost of installing 588 flare control devices is about \$3.7 million dollars with an average cost effectiveness of about \$716 per ton of VOC reduced. For the smallest individual tank battery subject to controls (6 tons/year), the flare cost effectiveness is estimated at \$1,471 per ton of VOC reduced.

Table 4: Tanks over 6 tpy – Control Cost Estimates for Flare Control Devices				
Affected Tanks [count]	Each Flare Annualized Cost	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [\$ /ton]
588	\$6,286.8	\$3,696,638	5,162	\$716

In addition to VOC reductions, this strategy will significantly reduce methane and ethane emissions from currently uncontrolled tanks. To calculate methane and ethane emission reductions, the Division determined the relative proportion of VOCs to methane and ethane based on reported average values from 30 natural gas liquid analyses submitted to the Division. Based on these analyses, methane/ethane emissions from condensate storage tanks are about 38% of the VOC emissions by weight. Accordingly, projected methane/ethane emission reductions from this proposed strategy are 1,963 tons per year or \$1,884 per ton of methane/ethane reduced.

3.3.8.1.3 Requiring Controls for Produced Water and Crude Oil Tanks

As discussed above, the Division is proposing to eliminate the distinction between condensate tanks and other storage tanks. If the Commission adopts this proposal, crude oil tanks and produced water tanks with uncontrolled actual VOC emissions of six tons per year or greater will require controls. Because produced water and crude oil tanks are identified separately in the Division's APEN data base, the costs and benefits for these two types of storage tanks are broken out separately.

The Division is proposing that all statewide produced water tanks with uncontrolled VOC emissions over 6 tons/year be required to install emission controls. Some uncontrolled produced water tanks could be co-located at sites with condensate or crude oil tanks that have flare controls, but pressure and flow differences may require the installation of a separate flare control device for the water tank. Consequently, the control costs are based on the assumption that each water tank battery will install a new flare control device. Based on an analysis of the APEN

database, the Division estimates that statewide there are 52 uncontrolled produced water tank batteries with VOC emissions over 6 tons/year.

Table 5: Produced Water Tank Battery Analysis

Tank Battery Type	Total Statewide Water Tanks
Controlled Water Tanks:	338
Uncontrolled Water Tanks:	530
Total:	868
Uncontrolled Tanks (≥ 6 tpy)	52

Based on the reported uncontrolled actual emissions, the Division estimates that the total VOC emission reduction associated with controlling these produced water tanks statewide is 457 tons per year.

Table 6: Produced Water Tank Battery – Emissions Analysis

Tank Battery Type	Uncontrolled VOC Emissions [tons/year]	Controlled VOC Emissions [tons/year]	VOC Emission Reduction [tons/year]
Uncontrolled Tanks (≥ 6 tpy)	641.4	184.4*	457

*Emission reduction estimated by accounting for 75% capture and 95% destruction efficiency.

The annualized cost of installing 52 flare control devices is about \$327,000, with an average cost effectiveness of about \$715 per ton of VOC reduced. For the smallest individual tank battery (6 tons/year), the flare cost effectiveness is estimated at \$1,471 per ton of VOC reduced.

Table 7: Produced Water Tanks – Control Cost Estimates for Flare Control Devices

Tank Size	Affected Tanks [count]	Each Flare Annualized Cost	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [\$/ton]
≥ 6 tpy	52	\$6,286.8	\$326,914	457	\$715

The Division is proposing that all statewide hydrocarbon liquid storage tanks with VOC emissions over six tons/year must install emission controls. Based on a recent analysis of 2013 APEN data, there are 67 reported crude oil tanks batteries statewide. Thirty seven of the tank batteries are already equipped with controls. Of the remaining thirty, eight are over the proposed six tons/year threshold. Given that approximately 5% of the total wells in the state report crude oil production to the Colorado Oil and Gas Conservation Commission (COGCC),³⁰ it appears

³⁰ Based on an analysis of 2010 COGCC data.

likely that the Division's APEN database may be undercounting crude oil tanks, either because these tanks have not been reported or because they are being reported as condensate tanks.³¹

Table 8: Crude Oil Tank Battery Analysis

Tank Battery Type	Total Statewide Crude Oil Tanks
Controlled Crude Oil Tanks	36
Uncontrolled Crude Oil Tanks	29
Total:	65
Uncontrolled Tanks (≥ 6 tpy)	8

The total VOC emission reduction associated with controlling these 8 crude oil tanks statewide is 118 tons per year.

Table 9: Crude Oil Tank Battery – Emissions Analysis

Tank Battery Type	Uncontrolled VOC Emissions [tons/year]	Controlled VOC Emissions [tons/year]	VOC Emission Reduction [tons/year]
Uncontrolled Tanks (≥ 6 tpy)	165.2	47.5*	117.7

*Emission reduction estimated by accounting for 75% capture and 95% destruction efficiency.

The annualized cost of installing eight flare control devices is about \$50,294 dollars with an average cost effectiveness of about \$427 per ton of VOC reduced. For the smallest individual tank battery (6 tons/year), the flare cost effectiveness is estimated at \$1,471 per ton of VOC reduced.

Table 10: Crude Oil Tanks – Control Cost Estimates for Flare Control Devices

Tank Size	Affected Tanks [count]	Each Flare Annualized Cost	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [\$ /ton]
≥ 6 tpy	8	\$6,286.8	\$50,294.4	117.7	\$427

3.3.8.1.4 Requiring Controls During the First 90 Days of Production Statewide

Under current requirements owners and operators of new and modified storage tanks outside the NAA have 90 days after the date of first production to determine if emissions from the tank trigger the requirement to install a control. Because production is typically at its highest during this initial period, significant emissions can occur before controls are installed. To address this

³¹ Prior to 2008 crude oil storage tanks were exempt from APEN reporting requirements, which may explain in part the small numbers of tanks identified in the system.

issue in the NAA, the Commission mandated in the 2008 Ozone Action Plan that all condensate tanks be controlled during the first 90 days. The Division is now proposing to expand this requirement to storage tanks throughout the state.

To calculate the cost effectiveness of this strategy, the Division first determined the number of new and modified storage tanks outside the NAA based on reported APEN data for the period of 2010-2012. Based on this APEN data, there are on average 141 new and modified tanks each year, with yearly reported uncontrolled actual emissions of 7,370 tons VOC. Assuming that emissions during the first 90 days equal 1/4th of the annual reported emissions,³² total uncontrolled actual VOC emissions from these tanks during the first 90 days is 1,842.5 tons. Assuming enhanced capture efficiency for these new tanks (see subsection 3.3.8.1.5 of this Regulatory Analysis) the flare control efficiency is 95%, and thus the calculated benefit from expanding the first 90 day control requirement to tanks outside the NAA will be 1,750.4 tons per year.

While the Division estimates that there are 141 new and modified storage tanks outside the NAA each year, the majority of these, 84, will require control devices regardless of this strategy since their uncontrolled actual emissions are over six tpy. For these 84 tanks, the cost of operating a flare during the first 90 days will be approximately 25% of the total annualized cost, or \$1,571.70 per tank. For the remaining 57 tanks with emissions less than six tons/year, because controls for these tanks will only need to be in place for 90 days, the Division assumes that each flare can control 3 tanks per year, which means that 19 new flares are required to comply with this proposed strategy. For other applications, the annualized cost of a flare is estimated to be \$6,287. Since flares required for this application will be relocated three times a year, the Division assumes an additional \$3,000 in annual relocation costs, for a total annualized cost of about \$9,287 per flare. Based on the emission reductions calculated above, the total cost effectiveness of this requirement is \$176/ton of VOC reduction.

Table 11: Control Cost Estimates for Flare Control Devices Required During the First 90 Days of Production

Storage Tank Threshold [tpy]	Number of New Storage Tanks	Number of New Flares	Annualized Cost Each Flare	Total Flare Cost	Total VOC Reduction [tons/year]	VOC Control Cost [\$ /ton]
<6	57	19	\$9,286.8	\$176,449.2	44.7	\$3,947
≥6	84	84	\$1,571.7	\$132,022.8	1,705.7	\$77
	141			\$308,472	1,750.4	\$176

Using the methodology discussed in subsection 3.3.8.1.2 of this Regulatory Analysis, the projected methane/ethane emission reductions from this strategy is 665.5 tons per year or \$464 per ton of methane/ethane reduced.

³² Because reported emissions typically are based on a calculation assuming a standard rate of production decline after the first 90 days, actual emissions during the first 90 days could be much higher.

3.3.8.1.5 Emission Capture Requirements for Controlled Petroleum Storage Tanks

In order for storage tank control requirements to be effective, emissions from the tank must be routed to the control device. Historically the Division has assumed that 100% of a tank's emissions will be captured and routed to the control device, typically a flare, resulting in a 95% reduction of emissions. Field observations using IR cameras and other methodologies indicate that in actuality emissions from controlled storage tanks often escape through the thief hatches and pressure relief valves (PRV) and therefore are not being combusted in the flare. This occurs when the tank cannot adequately contain the flashing emissions that occur when pressurized liquids from the separator are dumped into the atmospheric tank. To address this issue, the Division is proposing new regulatory language clarifying that all emissions from controlled storage tanks must be routed to the control device and that these tanks must be operated without venting emissions from thief hatches, PRVs and other openings, except when venting is reasonably necessary for maintenance, gauging, or safety of personnel and equipment.

To assure compliance with these capture standards, the Division's proposal requires that owners and operators of controlled storage tanks implement a STEM plan. Pursuant to the STEM plan, owners and operators must evaluate and employ appropriate control technologies and/or operational practices designed to meet the proposed capture requirements, and certify that these technologies and/or operational practices are designed to minimize emissions from the tank. The Division's STEM proposal also requires implementation of a two-pronged monitoring strategy involving a weekly³³ auditory, visual, and olfactory (AVO) inspection for all controlled tanks, and a periodic instrument based monitoring for tanks using EPA Reference Method 21, an IR camera or other Division approved monitoring device or method. As proposed, the frequency of this instrument based monitoring will depend on the level of uncontrolled actual emissions from the tank.

Table 12: Proposed Tiering for Instrument Based Tank Inspections

Tank Uncontrolled Actual VOC Emissions	Inspection Frequency
≥ 6 tpy to ≤ 12 tpy	Annually
> 12 tpy to ≤ 50 tpy	Quarterly
> 50 tpy	Monthly

In assessing the cost effectiveness of the proposed requirements, the Division first calculated the costs associated with implementing technological and/or operational changes at controlled tanks. For the purposes of this analysis the Division assumed that all tanks with uncontrolled actual emissions greater than or equal to 6 tons per year would need to be controlled consistent with the Division's proposal discussed in Section 3.3.1 of this Regulatory Analysis. Based on reported data, there are currently 5,310 storage tanks statewide with emissions greater than or equal to 6 tons per year. While the Division's proposal does not specify the type of technology or operational practices that operators will use, for the purposes of this analysis the Division

³³ There is an exception for the weekly inspection requirement where the operator loads out liquids from the storage tank on less than a weekly basis. In these circumstances the operator must conduct the inspection whenever liquids are loaded out, but no less often than every 30 days. Typically liquids are loaded out multiple times in a given week, meaning that for the majority of the tanks AVO inspections will be required weekly.

assumed that buffer bottle technology would be installed on each of the subject tanks.³⁴ The buffer bottle technology utilizes a small tank that is installed after the separator which allows for a secondary flash of pressurized liquids prior to dumping into the storage tank. The second-stage flash reduces the pressure of the liquids going to the tank and thereby helps to ensure that the tank can adequately handle the flashing emissions that occur when the liquids are brought to atmospheric pressure. Based on industry provided information, the estimated annual cost of a buffer bottle is set forth in Table 13.³⁵

Table 13: Annualized Cost Analysis for Buffer Bottle				
Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
Buffer Bottle	\$11,500			
Freight/Engr		\$600		
Installation		\$2,280		
Maintenance			\$2,500	
Subtotal Costs	\$11,500	\$2,880	\$2,500	
Annualized Costs*	\$1,593.8	\$192	\$2,500	\$4,285.8

* Annualized over 15 years at 5% ROR

The Division also calculated the costs associated with conducting enhanced inspections. Based on the proposed tiering, operators will need to conduct 24,840 tank inspections per year.³⁶

Assuming that each inspection takes two hours and utilizing a \$103/hour³⁷ in-house inspection cost and a \$134/hour contractor inspection cost (30% profit added to in-house rate), the total annual cost associated with conducting enhanced inspections under the proposed rule is \$5,392,010, which equates to \$1,015.4 per year for each tank that will be subject to STEM.

³⁴ Based on discussions with industry representatives during the stakeholder process there may be other less costly technologies and operational practices that could be used to ensure good emission capture from tanks such as replacing seals, more frequent maintenance, changing the size of piping going to the storage tank, and timing well dumps to avoid overloading the separator. There may also be other options for new facilities that allow for the capture and sale of additional gas such as the installation of high-low pressure separators or utilizing a liquids gathering system that eliminates atmospheric storage tanks at well sites.

³⁵ For this Regulatory Analysis, the Division increased the capital and maintenance costs for buffer bottles based on input from industry stakeholders.

³⁶ In practice, many operators are already conducting IR camera inspections at storage tanks, however, the Division does not have information regarding how many inspections are currently occurring.

³⁷ The hourly inspection cost is discussed below in Table 20.

Table 14: Instrument Based Tank Inspections Based on Proposed Tiering					
Tank Uncontrolled Actual VOC Emissions	Inspection Type/Hourly Rate	Number of Tanks	Inspection Frequency	Number of Inspections	STEM Inspection Costs
>6 tpy to ≤ 12 tpy	In-House/\$103	1,085	Annually	1,085	\$223,510
>12 tpy to ≤ 50 tpy	In-House/\$103	2,595	Quarterly	10,380	\$2,138,280
> 50 tpy	In-House/\$103	745	Monthly	8,940	\$1,841,640
Subtotal:		4,425		20,405	\$4,203,430
>6 tpy to ≤ 12 tpy	Contractor/\$134	323	Annually	323	\$86,564
>12 tpy to ≤ 50 tpy	Contractor/\$134	329	Quarterly	1,316	\$352,688
> 50 tpy	Contractor/\$134	233	Monthly	2,796	\$749,328
Subtotal:		885		4,435	\$1,188,580
Total:		5,310		24,840	\$5,392,010

The Division also considered whether additional costs should be included for conducting periodic AVO inspections. Because these activities are already required for controlled storage tanks under existing regulation, the Division did not include these costs in determining the total cost of the proposed capture requirements. The Division also did not include costs associated with certifying that selected technologies and/or operational practices are designed to minimize emissions, since costs for certifying capture efficiency are already included in the annualized cost of required flares.³⁸ Accordingly, the total projected annual cost of the proposed capture requirements based on the use of a buffer bottle and enhanced monitoring requirements is \$5,301.2 per tank.

To calculate the projected emissions reduction from the proposed capture requirements, the Division assumed a current capture rate of 75% for controlled tanks based on analytical work that the Division, EPA and others have performed. Based on this capture rate, the Division calculated the emissions reduction that would occur if the capture rate were increased to 100% using the following equation:

$$\text{Emission reduction} = [\text{uncontrolled VOC} \times (1 - (0.75 \times 0.95))] - [\text{uncontrolled VOC} \times (1 - 0.95)],$$

Using this equation as applied to the reported uncontrolled actual emissions from the 5,310 storage tanks statewide with emissions greater than or equal to six tons per day, the projected emission reduction from the proposed capture requirements is 53,386 tons per year. Included in the total are 33 existing crude oil tanks with flare controls (>6 tpy) and 8 crude oil tanks that would need flare controls (>6 tpy).

³⁸ See "Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination," Lesair Environmental, Inc., June 2008, at pg. 8.

Table 15: STEM Emission Control Analysis (Statewide)

Number of Tanks ≥ 6 tpy	Uncontrolled VOC [tons/year]	Controlled VOC (@ 71.25% Control) [tons/year]	Controlled VOC (@ 95% Control) [tons/year]	VOC Reduction [tons/year]
5,269	221,569	63,701	11,078	52,623
41	3,213	924	161	763
5,310	224,782	64,625	11,239	53,386

Applying this reduction to the costs calculated above, the cost effectiveness of these proposed requirements is \$527/ton of VOC.

Table 16: STEM Control Cost Estimates (Statewide)

Type of Technology	Number of Tanks	Each Device Annualized Costs [\$ /year]	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [\$ /ton]
Buffer Bottle	5,310	\$5,301.2	\$28,149,372	53,386	\$527.3

Using the average ratio of VOC to methane/ethane emissions from storage tanks, the projected methane/ethane reduction from this strategy is 20,287 tons per year, which equates to \$1,388 per ton of methane/ethane reduced.

During the Division's stakeholder process leading up to the Commission's rulemaking hearing, certain parties have raised questions about the Division's assumption that currently controlled tanks have a 75% capture efficiency. In light of this the Division has also calculated cost effectiveness based on the assumption that current capture efficiency is 50% and 95%. For the 50% case, current controlled emissions would be 118,011 tpy VOC. Accordingly, the emission reduction benefit from increasing capture to 100% would be 106,772 tons per year (118,011-11,239) and the cost effectiveness would be \$264/ton VOC³⁹. For the 95% capture scenario, current controlled emissions would be 21,916 tons per year VOC and the emission reduction would be 10,677 tons per year (21,916-11,239). Under this scenario, the cost effectiveness would be \$2,636/ton VOC⁴⁰.

While the buffer bottle technology offers a good alternative in a retrofit situation for reducing pressures to the tank and increasing emission capture, for new facilities, installation of a high-low pressure (HLP) separator to satisfy STEM may prove to be a better performing option. This equipment allows for two stages of separation of the gas and the liquids instead of the single stage separation accomplished in traditional separators. By adding a second stage of separation, the pressure of the liquids sent to the tank is significantly reduced, thereby helping to ensure

³⁹ This may overestimate the cost effectiveness given that if the current capture rate were only 50% additional costs could be required to increase the capture rate to 100%.

⁴⁰ This is a conservative calculation given that if the current capture rate were 95% it is likely that the control costs to increase the capture rate to 100% would be significantly less.

complete capture of flashing emissions instead of venting a portion of the emission stream through the thief hatch or PRV. Additionally, rather than being routed to the flare, as in the case of the buffer bottle technology, gas from the second stage of separation can be sent to a vapor recovery unit (VRU), recompressed and sent to the sales line, resulting in increased product recovery. Based on information provided from industry, the Division has calculated that the annual cost of a HLP separator w/VRU is about \$19,341.

Table 17: Annualized Cost Analysis for HLP Separator

Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
HLP/VRU	\$90,000			
Freight/Engr		\$1,648		
HLP/VRU Installation		\$11,154		
Maintenance			\$9,396	
VRU Recovered NG *			\$(3,382)	
Subtotal Costs	\$90,000	\$12,802	\$6,014	
Annualized Costs**	\$12,474	\$853	\$6,014	\$19,341

* Recovered NG fuel costs \$3.5/MCF (Henry Hub Spot Price - Aug. 2013) and average tank battery size of 63.2 tpy – based on 3-yr average of APEN data on storage tanks ≥ 6 tpy (uncontrolled VOC).

** Annualized over 15 years at 5% ROR

Unlike the retrofit situation analyzed above where the emission controls are already in place, it is appropriate in new installations to aggregate the cost of the HLP separator w/VRU with the costs of the control unit (flare) to determine the overall cost of controlling emissions from the tank. Based on the \$6,286.8 annual cost of a flare and annual instrument based monitoring costs of \$1,015.4 per tank, the total annual control costs for a new tank will be \$26,643 per year.

Based on an analysis of reported data for new tanks during the past three years, the average uncontrolled actual emissions of a new tank is 63.2 tpy. Assuming a 95% overall control efficiency, equipping a tank with an HLP separator and a flare will reduce the emissions from an average new tank by 60 tpy. This yields a cost effectiveness of \$444 per ton VOC reduced. If instead, the highest cost scenario (using a six tpy tank) is assumed, the cost effectiveness is \$4,674 per ton VOC. For methane ethane the cost per ton is \$1,168 per ton reduced on average.

3.3.8.1.6 LDAR Requirements for Compressor Stations and Well Production Facilities

Commission Regulation Number 7 requires owners and operators of gas processing plants in Colorado to implement LDAR programs to identify and repair fugitive emission leaks from components at these facilities. Under this requirement, owners and operators must conduct periodic inspections using EPA Reference Method 21⁴¹ and repair leaks within a prescribed time frame.

⁴¹ While EPA Reference Method 21 sets performance standards for inspection equipment rather than specifying technology, typically Method 21 inspections utilize photo ionization detectors (PIDs) to assess leak levels.

Although component leaks at compressor stations and well production facilities in Colorado are also a significant source of VOC and methane emissions, Regulation No. 7 does not currently include LDAR requirements for these facilities.⁴² To address these emissions, the Division is proposing regulatory changes that would establish LDAR requirements for compressor stations and well production facilities. Pursuant to this proposal, owners and operators of compressor stations and well production facilities will be required to conduct periodic leak inspections, and repair identified leaks. As specified, required inspections may be done either in accordance with EPA Reference Method 21 or utilizing an IR camera. The proposed language also allows the Division to approve other inspection methods as new leak detection technologies are demonstrated to be effective.

The proposed regulation establishes a tiered system to determine inspection frequency. For compressor stations the tiering is based on the uncontrolled actual leak emissions at the facility as follows:

Table 18: Proposed Tiering for Leak Inspections at Compressor Stations	
Component Leak Uncontrolled Actual VOC Emissions	Inspection Frequency
≤ 12 tpy	Annually
>12 tpy to ≤ 50 tpy	Quarterly
> 50 tpy	Monthly

For well production facilities the proposed tiering is based on uncontrolled actual emissions from the largest emitting storage tank at the facility as set forth in Table 19. The tiering is based on tank emissions rather than uncontrolled actual leak emissions in order to create an EPA Reference Method 21/IR camera monitoring schedule that is consistent with the monitoring schedule proposed as part of STEM emission capture requirements.⁴³

⁴² Although leak detection is not currently required at most of these facilities, some operators currently conduct voluntary leak detection and repair programs. Additionally, the Division has issued a limited number of permits that include some leak detection requirements. For the purposes of this analysis, however, the Division assumes that there is no leak detection occurring at well production facilities and compressor stations. Accordingly the actual additional costs that operators may incur may be less than the costs calculated in this analysis.

⁴³ Because there may be a limited number of instances where well production facilities don't have storage tanks, the proposal also provides that for tank-less facilities, the inspection schedule will be based on the facility's total VOC emissions. This provision is intended to apply to large facilities that utilize a liquids gathering system for transporting petroleum liquids to a centralized facility. These facilities are not included in the facility count used in this Regulatory Analysis, but because the number of these facilities in Colorado is extremely small this exclusion should have a negligible impact on the overall costs and emission reduction benefits of the proposed LDAR requirement. Additionally, because the costs and benefits from the proposed LDAR program increase at roughly the same rate, the cost effectiveness of the program for these facilities should mirror the cost effectiveness of the program as applied to facilities with tanks.

Table 19: Proposed Tiering for Leak Inspections at Well Production Facilities	
Tank Uncontrolled Actual VOC Emissions	Inspection Frequency
< 6 tpy	One Time (and Monthly AVO)
≥ 6 tpy to ≤ 12 tpy	Annually
>12 tpy to ≤ 50 tpy	Quarterly
> 50 tpy	Monthly

The Division utilized a multi-step process to calculate the estimated costs and benefits associated with the proposed LDAR requirements. First, the Division calculated an hourly inspection rate based on the total annual cost for each inspector divided by an assumed 1,880 annual work hours.⁴⁴ To calculate the total annual cost for each inspector, the Division included salary and fringe benefits for each inspector, annualized equipment and vehicle costs, and add-ons to account for supervision, overhead, travel, record keeping, and reporting. Based on the assumptions set forth in Table 20 below, the total annual cost for each inspector will be \$193,629, which equates to an hourly inspection rate of \$103.

Table 20: LDAR Inspector – Annualized Cost Analysis			
Item	Capital Costs (one time)	Annual Costs	Annualized Total Costs
FLIR Camera	\$122,000		
FLIR Camera Maintenance/Repair		\$7,500	
Photo Ionization Detector	\$5,000		
Vehicle (4x4 Truck)	\$22,000		
Inspection Staff		\$75,000	
Supervision (@ 20%)		\$15,000	
Overhead (@10%)		\$7,500	
Travel (@15%)		\$11,250	
Recordkeeping (@10%)		\$7,500	
Reporting (@10%)		\$7,500	
Fringe (@30%)		\$22,500	
Subtotal Costs	\$149,000	\$153,750	
Annualized Costs*	\$39,879	\$153,750	\$193,629
*over 5 years at 6% ROR	Annualized Hourly Rate		\$103

Initially, the Division assumed that conducting inspections in-house would be the lowest cost option since it would not involve additional profit to be paid to a contractor. For smaller companies that cannot fully utilize an IR camera, however, conducting inspections in-house may not be the most cost effective option. To account for this in this Regulatory Analysis, the Division assumed a 30% profit margin for contractors, which it added to the calculated hourly rate in instances where it appeared that contractors would be used to conduct the inspection (\$134 per hour).

⁴⁴ This assumes a 40 hour work week with ten holidays, two weeks of vacation, and one week of sick leave.

Second, the Division calculated the average amount of time that it would take to conduct an EPA Reference Method 21 inspection at compressor stations and well production facilities based on the number of components to be inspected and assuming that a component could be inspected every 30 seconds. The proposed rule also allows owners and operators to use IR cameras either as the sole inspection tool, or as a screening tool to identify potential leaking components followed by a Method 21 inspection. An IR camera inspection or IR Camera/Method 21 hybrid inspection can be conducted more quickly than a Method 21 inspection of each component. While the Division does not currently have actual data regarding how much faster an inspection could be completed using an IR camera, for the purpose of this analysis the Division assumed that an IR camera based inspection would take 50% of the time required for a Method 21 inspection.⁴⁵

For compressor stations, the Division used reported component counts for compressor stations within each of the tiers identified in Table 18 above. Based on these counts, and the inspection times per component discussed above, the Division calculated that the total inspection time per compressor station facility tier are as follows:

Table 21: Calculated Inspection Time Compressor Station Leak Inspections		
Component Leak Uncontrolled Actual VOC Emissions	Method 21 Inspection	IR Camera/ Hybrid Inspection
≤ 12 tpy	21.2 hours	10.6 hours
>12 tpy to ≤ 50 tpy	56.2 hours	28.1 hours
> 50 tpy*		

* there are currently no compressor stations in Colorado with calculated leaks at this level

For well production facilities, the Division has limited data on the number of components per facility. Based on this limitation, the Division did not attempt to calculate a separate inspection time for each of the proposed facility tiers, and instead used the overall average component count. Based on the limited available data, however, there does appear to be a distinction between component numbers at well production facilities in the NAA and well production facilities outside the NAA. Accordingly, the Division calculated separate inspection times for well production facilities by area as set forth in Table 22.

Table 22: Calculated Inspection Times for Well Production Facility Leak Inspections		
Area	Method 21 Inspection	IR Camera/ Hybrid Inspection
NAA	12.2 hours	6.1 hours
Rest of the State	6.8 hours	3.4 hours

⁴⁵ Based on the Division's own IR camera inspections, and reports from various parties during the stakeholder and prehearing process it appears that the Division's assumption may significantly overstate the actual time needed to conduct an IR camera inspection.

In addition to the travel costs that are built into the hourly inspection rate as set forth in Table 20, for the purposes of this Regulatory Analysis the Division also assumed an additional three hours in travel time for each inspection outside the NAA. This assumption reflects the fact that certain well sites in basins outside the NAA may be remote, requiring additional travel.

Next, the Division calculated the projected inspection costs for both compressor stations and well production facilities. To make this calculation the Division used industry reported emission data to determine the number of facilities that will be subject to annual, quarterly and monthly inspections to determine the total number of inspections for each tier, and multiplied these inspections by the calculated inspection time and projected hourly inspection rate. For compressor stations the Division assumed that all inspections would be conducted by 3rd party contractors. For well production facilities, the Division assumed that any company with 500 or more inspections per year would conduct inspections in-house, and that companies with less than 500 inspections per year would use contractors.⁴⁶ Because the proposed rule also requires owners and operators of well production facilities that are not subject to monthly instrument monitoring to conduct monthly AVO inspections the Division considered whether additional costs should be included for these inspections. Based on information provided during the Division's stakeholder process leading up to the Commission's rulemaking hearing it appears that operators already routinely conduct such inspections and repair leaks identified during these AVO inspections. Additionally, while the proposed rule may impose recordkeeping and reporting requirements associated with these AVO inspections, given the relatively small number of leaks that are expected to be identified, and the fact that any recordkeeping can be readily included in existing inspection and maintenance records the Division believes that any additional recordkeeping and reporting costs will be nominal relative to the overall cost of the LDAR program.

In its Initial EIA, the Division did not include the cost to repair leaking components or re-monitor these components post-repair to verify that the repair was effective, assuming that the cost to repair and re-monitor would be offset by the cost savings from capturing additional product as a result of repairs. Based on information that the Conservation Groups submitted as part of their Pre-Hearing Statement to the Commission, it appears that the Division's assumption in the Initial EIA was reasonable. See Exhibit A to CG-PHS, Testimony of David McCabe at pg. 8. Nevertheless, for this Regulatory Analysis, the Division has included both repair costs and estimated product savings from conducting leak detection activities. To calculate repair costs, the Division used EPA information regarding leaking component rates, component repair times, and hourly repair rates. Specifically, the Division assumed a \$66.24 hourly rate to repair components, and an average repair time of between 0.17 hours and 16 hours, depending on the both type of component and the complexity of the repair.⁴⁷ To calculate the number of leaking components the Division used industry reported component counts and assumed a 1.18% leaking

⁴⁶ Based on this assumption, 3,545 inspections per year will be conducted using 3rd party contractors.

⁴⁷ See "Equipment Leak Emission Reduction and Cost Analysis for Well Pads, Gathering and Boosting Stations, and Transmission and Storage Facilities Using Emission and Cost Data From the Uniform Standards," Bradley Nelson and Heather Brown, April 17, 2012; "Analysis of Emissions Reduction Techniques for Equipment Leaks," Cindy Hancy, December 21, 2011.

component rate for facilities subject to annual inspections.⁴⁸ To account for the projected additional emission reductions from quarterly and monthly inspection schedules the Division used annual leaking component rates of 1.77% for facilities with quarterly inspection schedules and 2.36% for facilities with monthly inspection schedules. To calculate the value of the additional product captured, the Division converted the amount of VOC and methane/ethane reduced to MCF of natural gas, with a price of \$3.50/MCF. With respect to re-monitoring, the Division determined that because of the small number of components that will require repair and the fact that re-monitoring can be undertaken at the same time as repair, any additional costs associated with re-monitoring are negligible.

Based on this methodology, the calculated annual inspection costs for compressor stations are set forth in Table 23.

Table 23: Compressor Station Leak Inspection Costs Using IR Camera/Method 21 Hybrid					
Compressor Station Fugitive VOC Tier [tpy]	Number of Compressor Stations	Annual Inspection Frequency	Time per IR Camera Inspection [hours]	Total Annual Inspection Time [hours]	Total Annual Inspection Cost
≤ 12 tpy	147	1	10.6	1,558.2	\$208,799
>12 to ≤ 50 tpy	53	4	28.1	5,957.2	\$798,265
≥ 50 tpy	0	12			
Total:	200			7,515.4	\$1,007,064

Repair costs associated with these inspections are set forth in Table 24 and fuel savings associated with these repairs are set forth in Table 25.

Table 24: Compressor Station Leak Repair Costs					
Compressor Station Fugitive VOC Tier [tpy]	Number of Compressor Stations	Leak Repair Rate [\$ /hr]	Number of Leaks per Compressor Station	Total Leak Repair Time per CS [hours]	Total Annual Repair Cost
≤ 12 tpy	147	\$66.24	30.1	23.0	\$223,957.4
>12 to ≤ 50 tpy	53	\$66.24	119.4	85.2	\$299,113.3
≥ 50 tpy	0	\$66.24	-	-	-
Total:	200				\$523,071

⁴⁸ This leaking component rate is consistent with the rate that the Louis Berger Group used in their Initial Economic Impact Analysis for Industry's Proposed Revisions to Colorado's Air Quality Control Commission Regulation No. 7 (DGS-PHS Ex. C), and is based on the leak rate utilized by Nelson and Brown in their analysis of leak reduction costs and benefits (See footnote 41).

Table 25: Compressor Station Recovered Natural Gas Value from Leak Repairs

Compressor Station Fugitive VOC Tier [tpy]	Number of Compressor Stations	Total Recovered Natural Gas per CS [tons/year]	Value of Natural Gas [\$MCF]	Conversion Factor [MCF/ton]	Total Annual Value of Recovered Natural Gas
≤ 12 tpy	147	10.2	\$3.5	35.8	\$187,875
>12 to ≤ 50 tpy	53	36.4	\$3.5	35.8	\$241,729
≥ 50 tpy	0		\$3.5	35.8	-
Total:	200				\$429,604

The total net costs for compressor station LDAR are set forth in Table 26.

Table 26: Compressor Station Net Leak Inspection and Repair Costs

Compressor Station Fugitive VOC Tier [tpy]	Number of Compressor Stations	Total Annual Inspection Cost	Total Annual Repair Cost	Total Annual Value of Recovered Natural Gas	Net Annual Leak Inspection and Repair Costs
≤ 12 tpy	147	\$208,799	\$223,957.4	\$187,875	\$244,882
>12 to ≤ 50 tpy	53	\$798,265	\$299,113.3	\$241,729	\$855,650
≥ 50 tpy	0		-	-	-
Total:	200	\$1,007,064	\$523,071	\$429,604	\$1,100,531

For well production facilities the estimated annual inspection costs are set forth in Table 27.

Table 27: Well Production Facility Leak Inspection Costs Using IR Camera/Method 21 Hybrid

Uncontrolled VOC at Storage Tank Battery Tier [tpy]	O&G Basin*	Number of Facilities	Annual Inspection Frequency	Total Number of Inspections	Inspection Time Per Inspection [hours]	Total Annual Inspection Cost
In-House Inspections at \$103/hour						
> 6 to ≤12	DJ/NAA	945	1	945	6.1	\$593,744
> 12 to ≤ 50	DJ/NAA	2,447	4	9,788	6.1	\$6,149,800
> 50	DJ/NAA	693	12	8,316	6.1	\$5,224,943
Subtotal:		4,085		19,049		\$11,968,487
In-House Inspections at \$103/hour						
> 6 to ≤12	ROS	173	1	173	6.4**	\$114,042
> 12 to ≤ 50	ROS	176	4	704	6.4	\$464,077
> 50	ROS	115	12	1,380	6.4	\$909,696
Subtotal:		464		2,257		\$1,487,815
Contract Inspections at \$134/hour						
> 6 to ≤12	DJ/NAA	150	1	150	6.1	\$122,610
> 12 to ≤ 50	DJ/NAA	153	4	612	6.1	\$500,249
> 50	DJ/NAA	118	12	1,416	6.1	\$1,157,438
Subtotal:		421		2,178		\$1,780,297
Contractor Inspections at \$134/hour						
> 6 to ≤12	ROS	140	1	140	6.4**	\$120,064
> 12 to ≤ 50	ROS	148	4	592	6.4	\$507,699
> 50	ROS	52	12	624	6.4	\$535,142
Subtotal:		340		1,356		\$1,162,905
Total:		5,310		24,840		\$16,399,504

* ROS = Remainder of State

** ROS inspection time includes additional 3 hours for travel time

Repair costs associated with these inspections are set forth in Table 28 and fuel savings associated with these repairs are set forth in Table 29.

Table 28: Well Production Facility Leak Repair Costs

Uncontrolled VOC at Storage Tank Battery Tier [tpy]	O&G Basin	Number of Facilities	Number of Leaks per Tank	Total Leak Repair Time per Tank [hours]	Total Annual Repair Cost
> 6 to ≤12	DJ/NAA	1,095	17.0	11.8	\$855,887
> 12 to ≤ 50	DJ/NAA	2,600	25.5	17.7	\$3,048,365
> 50	DJ/NAA	811	34.1	23.6	\$1,267,807
Subtotal:		4,506			\$5,172,059
> 6 to ≤12	ROS	313	9.7	7.7	\$159,645
> 12 to ≤ 50	ROS	324	14.5	11.6	\$248,956
> 50	ROS	167	19.4	15.4	\$170,356
Subtotal:		804			\$578,957
Total:		5,310			\$5,751,016

Table 29: Well Production Facility Recovered Natural Gas Value from Leak Repairs

Uncontrolled VOC at Storage Tank Battery Tier [tpy]	O&G Basin	Number of Facilities	Total Recovered Natural Gas per tank [tons/year]	Value of Natural Gas [\$/MCF]	Conversion Factor [MCF/ton]	Total Annual Value of Recovered Natural Gas
> 6 to ≤12	DJ/NAA	1,095	4.6	\$3.5	35.8	\$631,136
> 12 to ≤ 50	DJ/NAA	2,600	7.0	\$3.5	35.8	\$2,280,460
> 50	DJ/NAA	811	9.3	\$3.5	35.8	\$945,050
Subtotal:		4,506				\$3,856,646
> 6 to ≤12	ROS	313	4.6	\$3.5	35.8	\$180,407
> 12 to ≤ 50	ROS	324	6.8	\$3.5	35.8	\$276,061
> 50	ROS	167	9.1	\$3.5	35.8	\$190,418
Subtotal:		804				\$646,886
Total:		5,310				\$4,503,532

The total net costs for well production facility station LDAR are set forth in Table 30.

Table 30: Well Production Facility –Net Leak Inspection and Repair Costs

Uncont. VOC at Storage Tank Battery Tier [tpy]	O&G Basin	Total Annual Inspection Cost		Total Annual Repair Cost	Total Annual Value of Recovered Natural Gas	Net Annual Leak Inspection and Repair Costs
		In-House	Contractor			
> 6 to ≤12	DJ/NAA	\$593,744	\$122,610	\$855,887	\$631,136	\$941,105
> 12 to ≤ 50	DJ/NAA	\$6,149,800	\$500,249	\$3,048,365	\$2,280,460	\$7,417,954
> 50	DJ/NAA	\$5,224,943	\$1,157,438	\$1,267,807	\$945,050	\$6,705,138
Subtotal:		\$11,968,487	\$1,780,297	\$5,172,059	\$3,856,646	\$15,064,197
> 6 to ≤12	ROS	\$114,042	\$120,064	\$159,645	\$180,407	\$213,344
> 12 to ≤ 50	ROS	\$464,077	\$507,699	\$248,956	\$276,061	\$944,671
> 50	ROS	\$909,696	\$535,142	\$170,356	\$190,418	\$1,424,776
Subtotal:		\$1,487,815	\$1,162,905	\$578,957	\$646,886	\$2,582,791
Total:		\$13,456,302	\$2,943,202	\$5,751,016	\$4,503,532	\$17,646,988

Additionally, based on information in the Division's APEN reporting system, there are 2,799 well production facilities with uncontrolled actual storage tank emissions less than or equal to 6 tons per year that will be subject to a one-time instrument based inspection. The one-time cost for inspecting these facilities is estimated to be \$1,639,239.⁴⁹

Table 31: Well Production Facility Leak Inspection Costs Using IR Camera/Method 21 Hybrid

Uncontrolled VOC at Storage Tank Battery Tier [tpy]	O&G Basin	Number of Facilities and Inspections	Inspection Time Per Inspection [hours]	Inspection Type/Hourly Rate	Total Annual Inspection Cost
≤ 6	DJ/NAA	1,598	6.1	In-House/\$103	\$1,004,023
≤ 6	ROS	500	3.4	In-House/\$103	\$175,100
Subtotal:		2,098			\$1,179,123
≤ 6	DJ/NAA	389	6.1	Contractor/\$134	\$317,969
≤ 6	ROS	312	3.4	Contractor/\$134	\$142,147
Subtotal:		701			\$460,116
Total:		2,799			\$1,639,239

⁴⁹ To calculate these costs the Division used the same methodology applicable to periodic inspection costs, except that it did not include additional travel time for facilities outside the NAA based on the assumption that companies could coordinate these one-time inspections with visits to the facilities for other purposes.

The Division recognizes that there are likely additional facilities not included in the APEN database that will be subject to this one-time inspection requirement, thereby increasing the overall cost of the one-time inspection requirement. Roughly speaking the additional cost for one-time inspections will be proportional to the number of additional facilities, so that if there are twice the number of facilities, the overall cost will be approximately double. However, because the expected emission reduction benefit will increase roughly at the same rate as the cost of inspections the overall cost-effectiveness of the one-time inspection requirement should remain approximately the same regardless of the number of facilities.

Finally, the Division calculated the cost effectiveness of the proposed LDAR requirements based on the costs identified above and the projected emission reductions. To determine emission reductions the Division first calculated pre-inspection program VOC and methane emissions based on the reported component counts, standard emission factors for these components, and the average fraction of VOC and non-VOC emissions (methane/ethane). Based on EPA reported information, the Division calculated a 40% reduction for annual inspections, a 60% reduction for quarterly inspections, and an 80% reduction for monthly inspections.

Using this information the Division calculated that the total emission reductions from leaks at compressor stations will be 1,107 tpy VOC and 2,321 tons per year methane/ethane.

Table 32: Compressor Station Leak Inspection Emission Reductions						
Comp. Station Fugitive VOC Tier [tpy]	Number of Comp Stations	LDAR Program Reduction %	Fugitive VOC Emissions for each CS tier [tpy]	Total VOC Reduction [tpy]	Fugitive Methane-Ethane Emissions for each CS tier [tpy]	Total Methane-Ethane Reduction [tpy]
≤ 12	147	40%	10.1	588.0	15.5	911.4
> 12 to ≤ 50	53	60%	16.4	519.4	44.3	1,409.8
> 50		80%				
	200			1,107.4		2,321.1

Based on these reductions, the cost effectiveness of conducting leak inspections at compressor stations is estimated to be \$994/ton VOC and \$474/ton methane/ethane.

Table 33: Compressor Station Leak Inspection Cost Effectiveness using IR Camera/Method 21							
Comp. Station Fugitive VOC Tier [tpy]	Number of Comp Stations	Total Net Annual Inspection & Repair Cost	LDAR Program Reduction %	Total VOC Reduction [tpy]	VOC Control Cost [\$ /ton]	Total Methane-Ethane Reduction [tpy]	Methane -Ethane Control Cost [\$ /ton]
≤ 12	147	\$244,882	40%	588.0	\$416	911.4	\$269
> 12 to ≤ 50	53	\$855,650	60%	519.4	\$1,647	1,409.8	\$607
> 50			80%				
	200	\$1,100,531		1,107.4	\$994	2,321.2	\$474

For well production facilities the total emission reductions is estimated to be 14,015 tpy VOC and 21,927 tpy methane/ethane.

Table 34: Well Production Facility Leak Inspection Emission Reductions						
Uncontrolled VOC at Tank Battery Tier [tpy]	Number of Facilities	LDAR Program Reduction %	Fugitive VOC Emissions for each Tank Battery [tpy]	Total VOC Reduction [tpy]	Fugitive Methane-Ethane Emissions for each Tank Battery [tpy]	Total Methane-Ethane Reduction [tpy]
DJ/NAA						
> 6 to ≤ 12	1,095	40%	4.6	1,971.0	7.0	3,066.0
> 12 to ≤ 50	2,600	60%	4.6	7,280.0	7.0	10,920.0
> 50	811	80%	4.6	3,000.7	7.0	4,541.6
Subtotal:	4,506			12,251.7		18,527.6
Remainder of State						
> 6 to ≤ 12	313	40%	3.9	500.8	7.5	939.0
> 12 to ≤ 50	324	60%	3.9	745.2	7.5	1,458.0
> 50	167	80%	3.9	517.7	7.5	1,002.0
Subtotal:	804			1,763.7		3,399.0
Total:	5,310			14,015.4		21,926.6

Based on these reductions, the cost effectiveness of conducting ongoing instrument based inspections at well production facilities is estimated to be \$1,259/ton VOC and \$805/ton methane/ethane.

Table 35: Well Production Facility Leak Cost-Effectiveness Using IR Camera/Method 21

Uncont. VOC at Tank Battery Tier [tpy]	Number of Tanks	Total Net Annual Leak Inspection & Repair Cost	LDAR Program Reduction %	Total VOC Reduction [tpy]	VOC Control Cost [\$ /ton]	Total Methane-Ethane Reduction [tpy]	Methane-Ethane Control Cost [\$ /ton]
DJ/NAA							
> 6 to ≤ 12	1,095	\$941,105	40%	1,971.0	\$477	3,066.0	\$307
> 12 to ≤ 50	2,600	\$7,417,954	60%	7,280.0	\$1,019	10,920.0	\$679
> 50	811	\$6,705,138	80%	3,000.7	\$2,235	4,541.6	\$1,476
Subtotal:	4,506	\$15,064,197		12,251.7	\$1,230	18,527.6	\$813
ROS							
> 6 to ≤ 12	313	\$213,344	40%	500.8	\$426	939.0	\$227
> 12 to ≤ 50	324	\$944,671	60%	745.2	\$1,268	1,458.0	\$648
> 50	167	\$1,424,776	80%	517.7	\$2,752	1,002.0	\$1,422
Subtotal:	804	\$2,582,791		1,763.7	\$1,464	3,399.0	\$760
Total:	5,310	\$17,646,988		14,015.4	\$1,259	21,926.6	\$805

Additionally, for the 2,799 well production facilities with uncontrolled actual storage tank emissions equal to or less than 6 tons per year that will be subject to a one-time instrument based inspection, the calculated one-time benefit is 4,876 tons VOC and 8,000 tons methane/ethane, assuming a 40% reduction. Based on these reductions, for the one-time inspections of well production facilities with tanks that are less than six tons per year the cost effectiveness of the proposed rule is calculated to be \$409/ton VOC and \$249/ton methane/ethane.

In addition to the component LDAR requirements for compressor stations and well production facilities, the Division's proposal includes additional requirements designed to reduce leaks from open ended lines and valves, reciprocating compressors, and wet seal centrifugal compressors. These requirements mirror existing cost-effective requirements set forth in NSPS OOOO and other federal rules.

For open ended valves and lines at well production facilities and compressor stations, the proposal requires that each such valve or line be equipped with a cap, blind flange, plug or second valve commencing January 1, 2015. Alternatively, the Division's proposal allows operators to treat open-ended lines and valves as components and monitor them in accordance with the proposed LDAR requirements. As part of its LDAR cost effectiveness analysis detailed above, the Division included the costs of inspecting and repairing open ended lines and valves in its overall calculation. While the Division has not identified specific information regarding the costs and emission reduction benefits from equipping open ended lines with a cap, blind flange, plug or second valve it notes that the requirement has been included in a multitude of federal air quality rules, including NSPS VV, NSPS VVa, MACT H, MACT CC, MACT TT, MACT YY, MACT GGG, MACT III, and MACT MMM, dating back as far as 1983. Based on this

widespread prevalence in federal rules the Division believes that the proposal represents a simple and cost-effective strategy to reduce emissions from open-ended lines and valves. However, to the extent that it is not cost effective in a specific case operators can employ the monitoring option allowed for under the proposed rule.

For centrifugal compressors, the Division's proposal requires that hydrocarbon emissions from wet seal fluid degassing systems be reduced by 95% beginning January 1, 2015. In its updated technical support document for NSPS OOOO, EPA analyzed the cost-effectiveness of this strategy and found that accounting revenues from the capture of additional product, implementation of this strategy would on a per unit basis reduce VOC emissions by 19.5 tpy, methane emissions by 216.2 tpy, and result in a net cost savings of \$46,974.⁵⁰

With respect to reciprocating compressors, the Division's proposal requires that commencing January 1, 2015, the rod packing for reciprocating compressors located at compressor stations be replaced every 26,000 hours of operation or every 36 months. As with the requirement for centrifugal compressors, EPA analyzed this proposed strategy as part of the adoption of NSPS OOOO and found that it was a cost-effective way to reduce VOC and methane emissions. Specifically, EPA found that per compressor the strategy reduces VOC emissions by 1.9 tons per year and methane emissions by 6.8 tons per year, at a net cost of \$43 per ton of VOC reduced and \$12 per ton of methane reduced.⁵¹

3.3.8.1.7 Auto Igniter Requirements on Existing Flare Control Devices Outside the NAA

Unlike the NAA, flares used to control emissions at condensate tank batteries and glycol dehydration units outside the NAA are not required to have auto-igniters. The Division is proposing that all flares used to control emissions at condensate tank batteries and glycol dehydration units statewide should have auto igniters. Based on an analysis of the APEN database, the Division estimates the statewide number of existing flare control devices without auto-igniters on condensate tank batteries, glycol dehydration, produced water tanks, and crude oil tanks is 796. The reported uncontrolled actual emissions from these units are 53,101.1 tons per year VOC.

The estimated annualized cost for an auto-igniter is \$475 based on information that the industry provided to the Division in 2008, adjusted for inflation.⁵²

⁵⁰ See APCD-PHS Ex. HHHH pp. 6-1—6-3

⁵¹ See initial technical support document for NSPS OOOO (submitted as DGS-PHS Ex. NN) at pp. 6-12—6-17.

⁵² See "Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination," Lesair Environmental, Inc., June 2008.

Table 36: Auto Igniter Control Device – Retrofit Cost Analysis

Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
Auto Igniter	\$1,648			
Freight/Engineering		\$200		
Flare Installation		\$500		
Maintenance			\$200	
Subtotal Costs	\$1,648	\$700	\$200	
Annualized Costs*	\$228.4	\$46.7	\$200	\$475

* Annualized over 15 years at 5% ROR

The Division estimates that a flare without an auto-igniter could experience about 3% pilot light downtime (262.8 hours) over a one year period. During the downtime period, any VOC emissions routed to the flare control device are uncontrolled. Based on the total uncontrolled actual emissions of 53,101.1 tons per year VOC from units equipped with flares without auto-igniters, the emissions during this downtime period will be 1,593.1 tons of VOC. The Division assumes that as a result of the installation of an auto-igniter, the amount of downtime can be eliminated, for a total emission reduction of 1,251.7 tons/year. Given that the annualized cost of installing 796 auto-igniters is about \$378,100 the estimated cost effectiveness of this strategy is about \$302 per ton of VOC reduced.

Table 37: Auto Igniter Emission Reduction Estimates

Source Type for Existing Flare Controls	Number of Auto Igniters	Uncontrolled VOC [tpy]	Uncontrolled VOC Using 3% Downtime [tpy]	Total VOC Reduction [tpy]
Condensate Tanks	490	31,170.6	935.1	666.3
Dehydrators	131	16,372.0	491.2	466.6
Produced Water Tanks	172	4,842.2	145.3	103.5
Crude Oil Tanks	3	716.3	21.5	15.3
	796	53,101.1	1,593.1	1251.7

* Dehydrator flares assumed to have 100% capture and 95% destruction – thus 95% control. Tank flares are assumed to have 75% capture and 95% destruction – thus 71.25% control.

Table 38: Auto Igniter Control Cost Estimates (Outside NAA)

Number	Each Auto-Igniter Annualized Costs	Total Annualized Costs	VOC Reduction* [tons/year]	Control Costs [\$/ton]
796	\$475	\$378,100	1,251.7	\$302

3.3.8.2 Expanding Low Bleed Pneumatics Requirements Statewide

As part of the 2008 Ozone Action Plan the Commission adopted regulatory requirements mandating the use of low bleed pneumatic controllers in the NAA. The current proposal would expand this requirement statewide.

To estimate the costs and benefits of this proposed strategy, the Division estimated the number of high-bleed pneumatic devices based on Independent Petroleum Association of the Mountain States (IPAMS) survey data from 2006, which identified the average number of such devices per well. The Division then scaled this number up based on 2012 COGCC well count data. Based on this methodology, there are 9,877 high-bleed pneumatic devices outside the NAA. Assuming a 95% replacement rate, the proposed rule will result in the replacement of 9,384 high bleed devices with low bleed devices. Based on this count, and the average emission reductions per device replaced identified in the IPAMS survey, the projected benefit from the proposed expansion of the current NAA low bleed pneumatic rule will be approximately 14,921 tons per year VOC (40.9 tons per day). Based on this information and assuming an 80/20 ratio of methane/ethane to VOC by volume, the estimated methane/ethane reduction from this strategy is 17,100 tons per year.

The average retrofit cost of a high-bleed pneumatic device is based on costs from the 2008 cost study⁵³ adjusted for inflation. Utilizing this methodology, the annualized cost for each replaced device is \$169. However, because the reduced bleed rate results in more natural gas being sold, operators will receive additional revenue as a result of the installation of a low bleed device. Based on the emission reduction data from the IPAMS survey and August 2013 spot prices for natural gas, the estimated average value of the recovered gas will be \$1,268 for each device replaced. As a result, the net annual gain is \$1,084 per replaced device. Based on this projected net gain, this strategy will pay for itself in approximately one year and two months.

Table 39: Replace High-Bleed Pneumatics with Low-Bleed Pneumatics – Annualized Cost Analysis*

Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
Low/No Bleed Device*	\$1,033			
Labor		\$387		
Value of NG Saved**			\$(1,268)	
Maintenance			\$16	
Subtotal Costs	\$1,033	\$387	\$(1,253)	
Annualized Costs***	\$143	\$26	\$(1,253)	\$(1,084)

* Control device costs were developed based on an Oil and Gas Cost Study and information submitted by industry in 2008. However, those costs were escalated by 9.85% to reflect CPI-U increases that have occurred since 2008.

** Recovered NG fuel costs \$3.5/MCF (Henry Hub Spot Price - Aug. 2013)

*** Annualized over 15 years at 5% ROR

⁵³ See “Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination,” Lesair Environmental, Inc., June 2008.

Assuming 9,384 total devices replaced, adoption of this strategy will result in \$10,169,441 in annual cost savings.

Table 40: Low Bleed Pneumatic Control Cost Estimates (Outside NAA)				
Number	Each Device Annualized Costs	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [\$ /ton]
9,384	\$(1,084)	\$(10,169,441)	14,921	NA

The proposed rule also requires the use of no-bleed pneumatic devices if it is technically and economically feasible and where on-site electrical grid power is being used. Use of no-bleed pneumatic devices will further reduce emissions relative to the use of low bleed devices. Since the Division does not have information indicating the number of no-bleed pneumatic devices that could be required, it is not possible to calculate the cost effectiveness of this particular provision. However, because the proposed requirement expressly provides that use of no-bleed pneumatics is only required where economically feasible the Division assumes that any use of no-bleed pneumatic devices pursuant to the proposed rule will be cost effective.

3.3.8.3 Require Newly Constructed Gas Wells be Connected to a Pipeline or Route Emissions to a Control Device

Currently in Colorado, natural gas produced at oil and gas sites is typically routed to a transmission pipeline. With the advent of new drilling technologies, additional areas of the state without established pipeline infrastructure may experience oil and gas exploration and production. This can lead to instances where produced gas is vented or flared instead of being put into a transmission line. To date the Division has identified 61 instances in Colorado where this is occurring. To address this, the proposed regulation provides that for newly constructed, hydraulically fractured, or recompleted wells, the gas stream must either be connected to a pipeline or routed to a control device achieving 95% control efficiency. Currently all of the sites that are not routed to a pipeline are flaring their gas. Additionally, because venting the gas at such sites would create a safety issue, the Division assumes that in the limited future instances where the gas stream is not routed to a pipeline, operators will route the emissions to a flare or other control device. Accordingly, adoption of this portion of the proposed regulation will likely not result in any additional costs.

3.3.8.4 Control Requirements for Glycol Dehydrators

The Division is proposing to revise the control requirements applicable to glycol natural gas dehydrators statewide. Currently any glycol natural gas dehydrator with uncontrolled actual VOC emissions of 2 tons per year or greater that is located at a facility where the sum of uncontrolled actual emissions from all of the dehydrators at the facility is greater than 15 tons per year, must be equipped with a control device that reduces emissions by at least 90%. Under the Division's proposal, all existing dehydrators with uncontrolled actual emissions of 6 tons per year or greater VOC must be controlled with air pollution control equipment achieving at least 95% reduction. The proposal also provides that existing dehydrators with uncontrolled actual emissions of two tons per year or greater VOC must be controlled if they are located within

1,320 feet of a building unit or designated outside activity area. Finally, the proposal requires that all new dehydrators with uncontrolled actual emissions of two tons per year or greater VOC be controlled. The Division assumes that newly subject glycol dehydrators will be controlled using flares that achieve a 95% destruction efficiency. The annual cost for these units is \$6,286.80 per unit.

Based on industry reported APEN data, there are currently 433 uncontrolled dehydrators at sites with total dehydrator uncontrolled actual VOC emissions below 15 tpy. Of these, 217 have uncontrolled actual emissions greater than or equal to two tons per year. The total uncontrolled actual emissions for these 217 dehydrators are 1,827.5 tpy VOC. There are 148 dehydrators with uncontrolled actual VOC emissions greater than or equal to 6 tons per year. The total uncontrolled actual emissions for these 148 dehydrators are 1,549.7 tpy VOC. Currently, the Division does not have information regarding the location of these uncontrolled dehydrators relative to a building unit or designated outside activity area. Assuming, however, that all of the 2 to 6 ton dehydrators are located within 1,320 feet of a building unit or designated outside activity area and thus will require a control, the proposed requirement will reduce 1,736 tpy of VOC at a cost effectiveness of \$786/ton VOC. For the smallest dehydrator subject to the proposed rule (2 ton/year) the cost effectiveness is estimated to be \$3309 per ton of VOC reduced.

Table 41: Dehydrator Control Cost Estimates (2 TPY Control Threshold)

Number	Each Device Annualized Costs	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [\$ /ton]
217	\$6,286.8	\$1,364,236	1,736	\$786

Conversely, if it is assumed that none of the 2 to 6 ton existing dehydrators will require controls the proposed requirement will reduce 1,472 tpy of VOC at a cost effectiveness of \$632/ton VOC.

Table 42: Dehydrator Control Cost Estimates (6 TPY Control Threshold)

Number	Each Device Annualized Costs	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [\$ /ton]
148	\$6,286.8	\$930,446	1,472	\$632

3.3.8.5 Control Requirements for Downhole Well Maintenance and Liquids Unloading Events

Historically, Colorado has not regulated air emissions from temporary activities such as well completions and well maintenance at well production sites. Recently, however, EPA, Colorado and other jurisdictions have identified these activities as potentially large sources of emissions from the oil and gas sector. In recognition of this, the Colorado Oil and Gas Conservation Commission and more recently EPA have adopted requirements for green completions to reduce hydrocarbon emissions during well completion activities. The Division is now proposing additional regulatory requirements designed to reduce emissions during well maintenance.

Well maintenance is required when, over time, liquids build up inside the well and reduce gas and oil flow out of the well. To remove these liquids and improve flow, the liquids are blown out of the well under pressure. This process is typically referred to as liquids load-out or well blow-down. Historically emissions from well blow-downs are vented to the atmosphere. EPA has established emission factors for liquid unloading based on fluid equilibrium calculations to calculate the amount of gas needed to blow down a column of fluids blocking a well and Natural Gas STAR partner data on the amount of additional venting after a blow-down. Based on its calculations, EPA estimated that in the United States the combined methane emissions for liquid unloading and well completions in 2009, was 217 billion cubic feet, and that liquid unloading may account for 33% of the uncontrolled methane emissions from the natural gas industry.⁵⁴ For Colorado, the Division has calculated that emissions from well blow-downs in 2008 were approximately 9,306 tons of VOC per year.

To address these emissions, the Division is proposing a two pronged requirement aimed at reducing the number of required liquids unloading events and reducing the amount of emissions vented to the atmosphere during these events. Under the Division's proposal operators shall use best management practices to minimize the need for venting associated with downhole maintenance and liquids unloading. For example, EPA's Gas Star program advocates the use of a plunger lift system to reduce the need for liquids unloading. According to EPA, use of a plunger lift will on average pay for itself in less than one year through the capture of additional product. The Division's proposal also provides that emissions during well maintenance and liquids unloading shall be captured or controlled using best management practices to limit venting during well blow-downs to the maximum extent practicable. Based on information provided by Environmental Defense Fund, application of these requirements could result in annual VOC reductions of 2,881 tons and methane reductions of 19,207 tons per year. Given the wide variety of practices that this could entail, the Division currently does not have information about the precise cost-effectiveness of this provision. Given the fact that the proposal only requires use of best management practices, which takes into account the cost of the practices in a given situation, the Division assumes that the proposed strategy will be cost effective.

4 CLOSING SUMMARY

On December 13, 2013, interested parties, stakeholders and state representatives filed requests for a Regulatory Analysis. This Regulatory Analysis is a careful and considerate response to those Requests and is a good faith effort on the part of the Division.

The Division has addressed, to the best of its ability, issues related to the entirety of proposed revisions to Regulation 3, 6, and 7. The Division believes that the proposal before the Commission reflects a balanced approach that includes proven and cost effective strategies to reduce emissions from the oil and gas sector, while enabling the sector to continue to grow in a responsible and protective manner. The Division looks forward to the Commission's consideration of its proposal and alternate proposals of other parties at the February 2014 hearing.

⁵⁴ See EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990-2009*, April, 2011.

FINAL

ECONOMIC IMPACT ANALYSIS

**For Industry's Proposed Revisions to
Colorado Air Quality Control Commission
Regulation Number 3, 6, and 7 (5 CCR 1001-9)**

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Executive Summary

This document provides an economic analysis of the proposed revisions to Colorado Air Quality Control Commission (AQCC) Rules. This analysis is focused on specific parts of the regulations, including the costs for flares and auto-igniters, pneumatic controllers, storage tank emission management (STEM), and LDAR for well production facilities and compressor stations. Louis Berger has also estimated the value of the product saved as a result of the LDAR programs for well production facilities and compressor stations. Additionally, Louis Berger analyzed the impacts to marginally producing wells as they become less economically viable and are shut in or plugged as regulatory costs increase, resulting in loss of production, operator revenues, royalties, and severance taxes. Finally, Louis Berger provides estimates on the costs to the state to implement the proposed rules and regulations. This document also provides support for industry's proposed language.

Economic Impact Analysis

Important results of the analysis are summarized in table ES-1 and described in the bullets below.

- Louis Berger estimated pollution control costs using information obtained from industry sources. Total costs to add flares and auto-igniters to tanks between 6 and 20 TPY uncontrolled VOC emissions are estimated to be \$5.8 million, \$511,680, and \$7,872 for condensate, produced water, and crude oil tanks, respectively. Annualized costs of buffer bottles are estimated to be \$5,850, with a total annual cost of \$31.1 million.
- LDAR programs result in decreased emission reduction benefits after the initial year of program implementation. That is, after initial monitoring, leaks are found and fixed, resulting in reduced leak frequencies and emissions. These decreased leak frequencies in subsequent years affect the cost effectiveness of the regulations. As emissions reductions decline in subsequent years, LDAR annualized costs decrease by a smaller proportion; therefore, costs per ton of VOC reduced in subsequent years are significantly higher in subsequent years compared to the initial year of implementation. Figure ES-1 shows how the emission reductions decline while LDAR costs per ton of VOC increase after the initial year. This figure also demonstrates the disparity in costs for the facilities with differing levels of uncontrolled emissions, with lower emitting tanks having a much higher cost per ton of VOC reduced than the higher emitting tanks.

**Table ES-1: Summary of Louis Berger Final EIA Results in Comparison to the
Division's Updated EIA Estimates**

Item	Louis Berger Estimate			Division Estimate		
	Total Annual Cost	Per Facility/ Tank Costs	Cost Per Ton of VOC Reduced	Total Annual Cost	Per Facility/ Tank Costs	Cost Per Ton of VOC Reduced
Lowering Threshold for Flares and Auto Igniters for Tanks						
Condensate Tanks	\$5.8M	\$9,840	\$988	\$3.7M	\$6,287	\$716
Produced Water Tanks	\$511,680	\$9,840	\$1,121	\$326,914	\$6,287	\$715
Crude Oil Tanks	\$78,720	\$9,840	\$670	\$50,294	\$6,287	\$427
Storage Tank Emission Management Plan (buffer bottle and inspections)						
Buffer Bottle	\$31.1M	\$5,850	-	\$21.0M	\$3,949	\$391
Initial Year STEM Costs (with buffer bottle)						
6 to 12 TPY	\$16.2M	\$11,453	\$4,800	\$5.6M	\$4,147	NA
12 to 50 TPY	\$39.9M	\$13,669	\$1,945	\$13.8M	\$4,741	NA
Greater than 50	\$21.0M	\$21,433	\$555	\$6.2M	\$6,325	NA
Total	\$77.1M	\$14,509	\$1,250	\$25.6M	\$4,875	\$4,800*
Subsequent Year STEM Costs (with buffer bottle)						
6 to 12 TPY	\$16.0M	\$11,324	\$20,172	\$5.6M	\$4,147	NA
12 to 50 TPY	\$38.5M	\$13,164	\$7,960	\$13.8M	\$4,741	NA
Greater than 50	\$19.5M	\$19,903	\$2,192	\$6.2M	\$6,325	NA
Total	\$73.9M	\$13,915	\$5,097	\$25.6M	\$4,875	\$4,800*
LDAR for Well Production Facilities						
Initial Year LDAR Costs						
Less than 6 TPY	\$19.8M	\$6,995	\$3,629	\$1.3M	\$470	NA
6 to 12 TPY	\$9.8M	\$6,962	\$3,611	\$663,993	\$470	\$256
12 to 50 TPY	\$56.2M	\$19,227	\$9,818	\$5.5M	\$1,881	\$682
Greater than 50	\$50.9M	\$51,999	\$25,390	\$5.5M	\$5,643	\$1,533
Total	\$136.7M	\$16,778	\$8,590	\$13.0M	\$1,598	\$819
Subsequent Year LDAR Costs						
Less than 6 TPY	\$3.0M	\$1,051	\$5,454	\$1.3M	\$470	NA
6 to 12 TPY	\$6.3M	\$4,452	\$9,815	\$663,993	\$470	\$256
12 to 50 TPY	\$27.3M	\$9,336	\$20,261	\$5.5M	\$1,881	\$682
Greater than 50	\$21.6M	\$22,097	\$45,855	\$5.5M	\$5,643	\$1,533
Total	\$58.2M	\$7,138	\$19,354	\$13.0M	\$1,598	\$819
LDAR Costs for Compressor Stations						
Initial Year LDAR Costs						
Less than 12TPY	\$3,873,936	\$26,353	\$3,465	\$154,262	\$1,049	\$260
12 to 50 TPY	\$11,532,775	\$217,599	\$17,344	\$589,763	\$11,128	\$1,131
Greater than 50	-	-	-	-	-	-
Total	\$15,406,710	\$77,033	\$8,641	\$744,025	\$3,720	\$667
Subsequent Year LDAR Costs						
Less than 12TPY	\$2,020,457	\$13,745	\$7,681	\$154,262	\$1,049	\$260
12 to 50 TPY	\$4,446,685	\$83,900	\$28,421	\$589,763	\$11,128	\$1,131
Greater than 50	-	-	-	-	-	-
Total	\$6,467,142	\$32,336	\$15,416	\$744,025	\$3,720	\$667
Value of Product Savings – Initial Year						
Well Production Facilities	\$12.4M	\$1,532	-	NA	NA	NA
Compressor Station – Initial Year	\$1.3M	\$6,993	-	NA	NA	NA
Value of Product Savings – Subsequent Years						
Well Production Facilities	\$2.3M	\$289	-	NA	NA	NA
Compressor Stations	\$329,453	\$1,647	-	NA	NA	NA
Division Implementation Costs of Proposed Rules						
Hours	12,282			0		
FTE	6.1			0		

*Calculated based on the emission reductions associated with the STEM Control Analysis on page 12 of Division's Updated EIA.

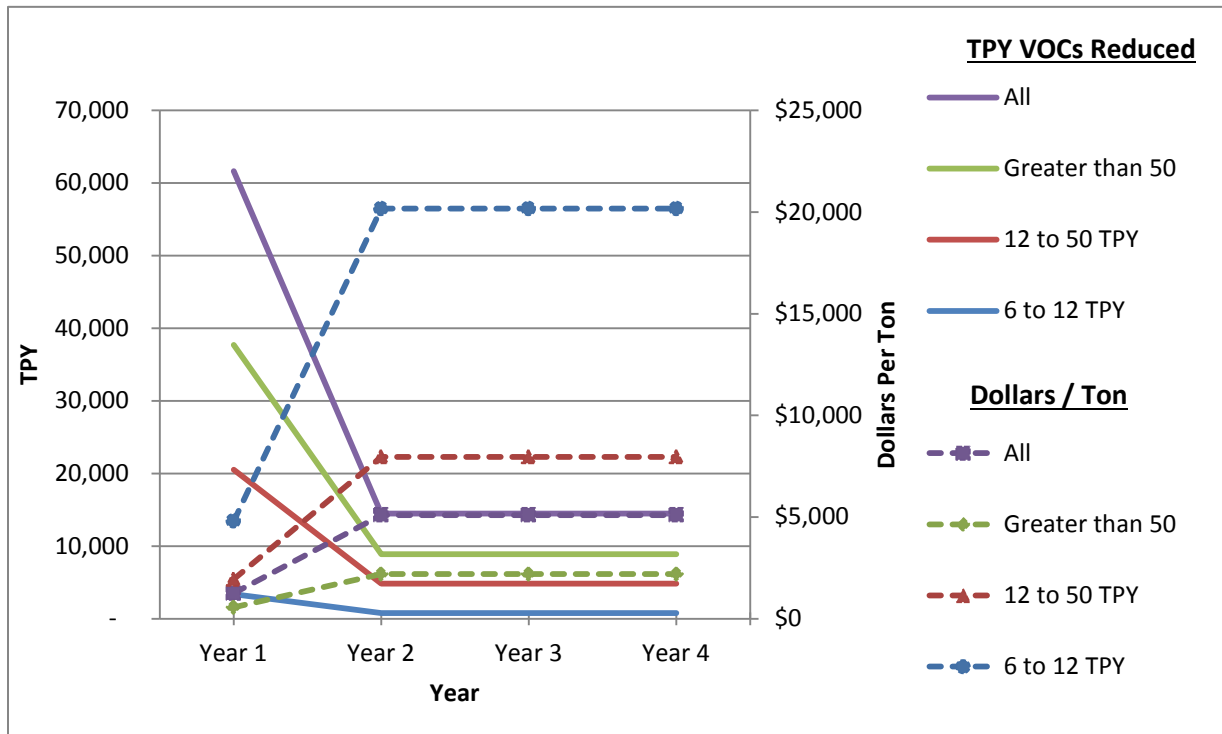


Figure ES-1: STEM Emission Reductions and Cost Per Ton of VOC Reduced

- STEM costs are estimated to be \$77.1 million in the initial year and \$73.9 million in subsequent years, while the cost per ton of VOC reduced is \$1,250 in the initial year and \$5,097 in subsequent years, on a recurring annual basis.
- Inspections and LDAR programs are more expensive to implement in the attainment area in comparison to the relatively dense operations in the non-attainment area due to the additional travel time, travel expenses, and fewer inspections possible on an annual basis in the attainment area. The STEM costs show that across all tank levels, the attainment area tanks have \$1,000 higher costs per tank per year than in the non-attainment area to implement this program. Similar results occur for well production facilities, with LDAR costs per facility in the initial year higher in the attainment area than non-attainment area for each level of monitoring required.
- LDAR costs for well production facilities are considerable, with initial year costs of \$136.7M (\$16,778 per facility) and subsequent recurring annual costs of \$58.2 million (\$7,138 per facility). The cost per ton of VOC reduced is \$8,590 in the initial year and \$19,354 in the subsequent years on an annual recurring basis.
- LDAR costs for compressor stations are \$15.4 million in the initial year (\$77,033 per compressor station) and subsequent recurring annual costs of \$6.5 million (\$32,336 per compressor station). The cost per ton of VOC reduced is \$8,641 in the initial year and \$15,416 in the subsequent years on an annual recurring basis.
- The total cost to expand the regulatory mandate to modify or retrofit high-bleed pneumatic devices statewide was estimated to be \$32 million. This includes the cost to replace an

estimated 9,800 high-bleed devices that are located at facilities outside the nonattainment area. When considering the amount of gas that can be recovered with the low-bleed devices, payback of the costs are expected to occur within 2.8 years. .

- Louis Berger estimated the product savings that can be expected from LDAR requirements for well production facilities and compressor stations. In the initial year, the value of the product captured represents approximately 8.7 percent of the LDAR costs. In subsequent years, the value of the natural gas captured represents 4 and 5 percent of the LDAR costs in subsequent years for well production facilities and compressor stations, respectively. The Economic Impact Analysis requires an assessment of the cost for the Division to implement the proposed rule changes. Oversight of an LDAR program, STEM plans, and annual report review of 5,312 tank batteries, 5,312 well production facilities, and 200 compressor stations with possibly hundreds of thousands of components would require additional Division manpower. Louis Berger reviewed the revised (November 21, 2013) Regulations 3, 6 and 7 to understand the implementation costs to the Division associated with the new rules. The net increase in the number of labor hours at the Division as result of the proposed regulations is anticipated to be approximately 12,282 labor hours annually. Notably, the Division would need 5,600 hours to review and approve initial STEM plans required under Regulation 7, the largest estimated time commitment for the Division. This represents approximately 6.1 FTEs of additional staff for the Division to review, oversee, inspect, manage, and approve various requirements associated with the proposed rules. Therefore, Louis Berger concludes that the Division would incur additional net costs to implement the proposed requirements beyond current expenditures.

In order to gain an understanding of the potential indirect costs to businesses, in particular small businesses if the proposed rules were implemented, Louis Berger evaluated the impacts on small, marginally producing wells within the state. Marginally producing wells with production less than 2 BOPD represent over half (55 percent) of the total producing wells in the state (46,495) as of 2013. Under current economic and regulatory conditions, the economic limit for marginally producing wells was estimated to be 0.43 BOPD, which is the point at which revenues would no longer cover operating expenses and the well would be shut in. Additional operating costs associated with the proposed rules were estimated per well production facility and tank and included in the analysis. Over time, the additional cost burden would result in as much as 128.6 million barrels of oil being left in place and not produced. The calculated present values for these losses include \$1.9 billion in lost revenue to producers, \$384 million in lost royalties and \$96 million in lost severance taxes.

- Support of Industry's Proposed Language

The results of the final economic impact analysis presented here support the industry's key suggested revisions to the Division's proposed rule. Specifically, the proposed revisions will allow similar emission reductions to be achieved in a cost effective, achievable, and reasonable manner. Key points to the analysis include:

- Diminishing marginal benefits associated with LDAR programs implies decreasing cost effectiveness after initial rounds of inspections and repairs. Reducing the monitoring to reflect

successful LDAR implementation reduces costs and improves the cost effectiveness of the proposed rule compared to the Division's proposal while maintaining program integrity through realized emission reductions. The "step-down" of monitoring frequency, which rewards companies with four inspections with no leaks, is an example of how the industry changes to the proposed rule would provide incentives for industry to maintain compliance and reduce costs for good behavior.

- Generally, compliance costs of STEM and LDAR for small tanks and well production facilities are more burdensome than for larger facilities on a cost per ton basis. As such, requiring a one-time LDAR inspection and monthly AVO for all facilities (including all well production facilities) with uncontrolled emissions between 2 and 6 TPY would improve the overall cost effectiveness of the proposed rule by limiting the very high costs per ton of VOC reduced incurred by very small facilities with very small VOC fugitive emissions.
- Compliance costs are higher for operations outside of the non-attainment area as the distance among facilities and tanks increases inspection travel time and expenses. Limiting the geographic scope to the non-attainment area will improve the cost effectiveness of the proposed rule.
- Allowing for the use of other established technology, such as the tunable diode laser absorption spectroscopy technology (TDLAS) as an option for inspection monitoring, would reduce costs to industry with faster inspections and reduced camera training requirements, among other factors.

Economic Impact Analysis

This document provides an economic analysis of the proposed revisions to Colorado Air Quality Control Commission (AQCC) Regulation Number 3, 6 and 7. This analysis is focused on the specific parts of the regulation, including the costs for flares and auto-igniters, STEM, LDAR for well production facilities and compressor stations, and pneumatic controllers. Louis Berger has also estimated the value of the product saved as a result of the LDAR programs for well production facilities and compressor stations. Additionally, Louis Berger analyzed the impacts to marginally producing wells as they become less economically viable and are shut in or plugged as compliance costs increase resulting in a loss of production, operator revenues, royalties, and severance taxes. Finally, Louis Berger provided estimates on the costs to the state to implement the proposed rules and regulations.

Lowering Statewide Tank Control Threshold (from 20 tpy to 6 tpy)

Louis Berger evaluated the costs to industry associated with installing flares and auto-igniters on condensate tanks with uncontrolled emissions between 6 TPY and 20 TPY. The analysis used the state's estimate of 588 condensate tanks that that would be affected by the change in the regulatory threshold, along with updated costs estimated by the EPA and in the industry survey.

Louis Berger developed cost estimates for flares and auto-igniters using data and information obtained from an industry survey conducted in 2013 and data from the EPA. The capital, non-recurring and annual costs were obtained from the EPA.¹ Because the costs were reported in 2008 dollars they were escalated to 2013 dollars using the GDP price index obtained from the U.S. Office of Management and Budget.² These costs were annualized for an 11-year life of the equipment based on information obtained from the industry survey at a 5 percent interest rate. The annual cost for the flare is estimated to be \$9,840 (Table 1).

Table 1: Estimated Cost for Flares and Auto-Igniters

Item	Estimated Cost (2013\$)
Capital and Non-Recurring Cost	\$35,070
Annual Costs	\$5,823
Annualized Capital Costs	\$4,018
Total Annual Costs	\$9,840

The Division estimated the cost per ton of VOC emission reductions by lowering the statewide tank control threshold from 20 TPY to 6 TPY. According to the Division's analysis, there are 588 condensate tanks that would be affected by this rule change and that by adding flares to these particular tanks, VOC emissions would decline by 5,162 TPY. Louis Berger analyzed the cost of lowering the threshold from 20 tpy to 6 tpy using the flare cost estimate summarized above. The results are summarized in Table 2.

¹ EPA. 2011. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Technical Support Document for Proposed Standards.

² Office of Management and Budget. 2013. Fiscal Year 2014. Gross Domestic Product and Deflators Used in Historic Tables. Table 10.1. Available: <http://www.whitehouse.gov/sites/default/files/omb/budget/fy2014/assets/hist.pdf>

When the costs are separated by uncontrolled emissions, the differences are significant. For tanks with lower uncontrolled emissions (6 to 10 TPY), the control costs are double what they are for the higher emitting tanks (between 10 and 20 TPY). Average cost per ton of VOC reduced is estimated to be \$1,121.

Table 2: Estimated Cost Per Ton of VOCs Reduced for Condensate Water Tanks

Uncontrolled Emissions	Number of Tank Batteries Affected	Average Uncontrolled Emissions per tank	Total Uncontrolled Emissions	Emission Reduction with Flare and Auto-Igniter	Total Cost of Flares Per Tank Category	Cost Per Ton of VOC Reduced Per Tank Category
(1)	(2)	(3)	(4) = (3) * (2)	(5) = (4) * 0.7125	(6) = (2) * \$9,840	(7) = (6)/(5)
6 to 10	235	7.35	1,729	1,232	\$2,314,368	\$1,879
10 to 20	353	13.98	4,932	3,514	\$3,471,552	\$988
Total Affected (State Estimate)	588	12.32	7,244	5,161	\$5,785,920	\$1,121

Using the same logic and data as described for condensate tanks, the controls for produced water tanks and crude oil tanks yields the following results. According to the Division's analysis, there are 52 produced water tanks and 8 crude oil tanks. Louis Berger believes that there are considerably more crude oil tanks than are reported in the APEN. However, without additional data, Louis Berger used the Division's estimate of 8. Cost per ton of VOC reduced for produced water and crude oil tanks are estimated to be \$1,121 and \$670, respectively.

Table 3: Estimated Cost Per Ton of VOCs for Produced Water Tanks

Uncontrolled Emissions	Number of Produced Water Tanks Affected	Average Uncontrolled Emissions per tank	Total Uncontrolled Emissions	Emission Reduction with Flare and Auto-Igniter	Total Cost of Flares Per Tank Category	Cost Per Ton of VOC Reduced Per Tank Category
(1)	(2)	(3)	(4) = (3) * (2)	(5) = (4) * 0.7125	(6) = (2) * \$9,840	(7) = (6)/(5)
Total Affected (State Estimate)	52	12.32	641	456	\$511,680	\$1,121

Table 4: Estimated Cost Per Ton of VOCs for Crude Oil Tanks

Uncontrolled Emissions	Number of Oil Tanks Affected	Average Uncontrolled Emissions per tank	Total Uncontrolled Emissions	Emission Reduction with Flare and Auto-Igniter	Total Cost of Flares Per Tank Category	Cost Per Ton of VOC Reduced Per Tank Category
(1)	(2)	(3)	(4) = (3) * (2)	(5) = (4) * 0.7125	(6) = (2) * \$9,840	(7) = (6)/(5)
Total Affected (State Estimate)	8	20.62	165	118	\$78,720	\$670

Emission Capture Requirements for Controlled Petroleum Storage Tanks

This section of the analysis evaluates requirements under the Storage Tank Emissions Management (STEM) plan, including costs of adding a buffer bottle and implementing a LDAR program. With data collected from the industry survey conducted in 2013, Louis Berger estimated an annual cost for buffer bottles of \$5,850, as described in Table 5.

Table 5: Estimated Cost for Buffer Bottles

Item	Estimated Cost (2013\$)
Capital and Non-Recurring Cost	\$25,000
Annual O&M Costs	\$2,500
Annualized Capital Costs*	\$3,350
Total Annual Costs	\$5,850

*Capital costs and non-recurring costs were annualized over 9 years, the estimate life of the control technology.

The STEM program would require instrument based monitoring. The monitoring frequency would be based on the uncontrolled emissions of various tanks as reported in the APEN database. Louis Berger estimated the LDAR costs using data and information obtained through an operator survey and follow up interviews. Table 6 summarizes the cost assumptions for the analysis.

Table 6: STEM Cost Assumptions for Tanks (2013\$)

Item	LDAR			AVO		
	Estimated Cost	Annualized*	Unit Cost	Estimated Cost	Annualized*	Unit Cost
Capital and Non-Recurring Costs						
Camera	\$122,000	\$28,179	\$46.96/inspection in NAA \$70.45/inspection in the AA			
Vehicle	\$30,000	\$6,929	\$11.54/inspection in the NAA \$17.32/inspection in the AA			
Program set up costs (i.e., Tagging, software, travel, etc.)	\$1,000	\$231	\$231/Tank	\$500	\$115.49	\$115.49/tank
Inspection, Operations and Maintenance costs						
Assume one camera can inspect 2 tanks a day in the AA, 400 tanks/year; 3 tanks per day in the NAA, 600 tanks/year; 10 weeks for repair and training. Assume weekly inspections for all tanks over 6 TPY.						
Inspection Labor, including travel time						
Hourly Rate:	\$150		\$150/hour	\$100		\$100/Hour
Inspection and Travel Time (NAA and crude)	3		4.75 hours	.5		0.5 Hours
Inspection and Travel Time (AA)	4		5.75 hours	.5		0.5 Hours
Camera/Inspection training	\$7,500		Per 100 Tanks	\$7,500		\$7,500/100 tanks/year
Camera repair	\$12,500		Camera			\$12,500/camera/year
Travel and per diem costs (NAA Condensate and Crude Oil)	\$30		Inspection			\$30/inspection
Travel and per diem costs (AA Condensate)	\$40					\$40/inspection
Supervision	\$100 (annual, quarterly) \$200 (monthly)		Tank			\$100/tank/year \$200/tank/year
Compiling data, record-keeping and reporting	\$1,530 (annual, quarterly) \$3,060 (monthly)		Tank			\$1,530/tank/year \$3,060/tank/year

*Camera and set up costs annualized at 5% over 5 year-life of the equipment.

Louis Berger estimated the repair costs using information from a Canadian study and a Trihydro report that provide estimates of the number of components, potential number of leaks, and average leak

frequency for production tanks.³ Louis Berger assumed for this cost estimate that the typical production tank in Colorado has 38 components (Clearstone Engineering 2013) with an initial leak rate of 1.7 percent (Trihydro 2014), which equates to 0.65 components discovered leaking during each inspection. The Trihydro report indicates that subsequent leak frequencies associated with quarterly LDAR drop to 0.4 percent (0.15 leaking components per production tank), which was used to estimate the number of leaks repaired and re-monitored in subsequent years. Costs to repair components were obtained from Nelson and Brown (2012) and include only the labor needed to repair the leak, not materials and equipment costs.⁴ Data and cost assumptions for the repair and re-monitoring costs are summarized in table 7. The re-monitoring cost was assumed to apply to the 25 percent of leaks, and the inspection and travel costs were obtained from the operator survey, with a cost estimate of \$480 per inspection in the non-attainment area and \$640 in the attainment area.

Table 7: Repair and Re-monitoring Cost Assumptions

Percent of Leaks	Type of repair	Repair Time (hours)	Hourly Rate	Re-monitor Cost (per leak)
75%	On-line	1	\$75	-
25%	On the ground	4	\$75	\$480 (NAA) \$640 (AA)

The total estimated cost of the proposed STEM program, which includes the costs for the inspections and the buffer bottles, are summarized in the following two tables. Total STEM costs include annualized capital costs, recurring inspection, operations, and maintenance costs, buffer bottle costs, repair costs, and re-monitoring costs. Total costs for all storage tanks are estimated to be \$77.1 million, of which the non-attainment area tanks account for \$64.1 million. When comparing the costs per condensate tank in the attainment area and non-attainment area over all the different types of tanks, costs per tank in the attainment area are approximately \$1,000 higher than tanks in the non-attainment. The higher costs in the attainment area due to longer travel times and per diem costs, as ability to perform fewer inspections on an annual basis. For the greater than 50 TPY tanks, the STEM costs are \$23,676 per tank in attainment area compared with the non-attainment area STEM costs of \$20,966 per tank. The STEM costs are provided in Tables 8.1 and 8.2.

³ Clearstone Engineering, Ltd. 2013. Technical Report: Draft Update of Fugitive Equipment Emissions Factors. Prepared for the Canadian Association of Petroleum Producers. August. See Tables 5 and 12.

Trihydro Corporation. 2014. Colorado Regulation/Litigation Support. Prepared for WPX Energy, Inc. January 6.

⁴ Nelson, Bradley and Heather Brown. 2012. Equipment Leak Emission Reduction and Cost Analysis for Well Pads, Gathering and Boosting Stations, and Transmission and Storage Facilities Use Emission and Cost Data from the Uniform Standards. Memorandum to Greg Nizich and Bruce Moore, EPA. April

Table 8.1: Initial Year STEM Cost Analysis, Part 1

Tank Uncontrolled VOC Emissions	Monitoring Requirement	Number of Storage Tanks and Crude Oil Tanks	Number of inspections/ Year	Capital Costs for Inspections (annualized) (1)	Annual Costs for Inspections, O&M (2)	Number of Cameras Needed
Crude Oil Tanks						
6 to 12 TPY	annually	23	23	\$9,314	\$114,080	-
12 to 50 TPY	quarterly	5	20	\$2,903	\$32,000	-
Greater than 50	monthly	14	168	\$14,681	\$178,680	1
Total	-	42	211	\$26,898	\$324,760	1
Attainment Area Condensate Tanks						
6 to 12 TPY	annually	325	325	\$141,125	\$1,676,500	1
12 to 50 TPY	quarterly	323	1,292	\$225,305	\$2,323,920	4
Greater than 50	monthly	165	1,980	\$230,950	\$2,337,850	5
Total	-	813	3,597	\$597,381	\$6,338,270	10
Non-Attainment Area Condensate Tanks						
6 to 12 TPY	annually	1,065	1,065	\$431,297	\$5,307,400	2
12 to 50 TPY	quarterly	2,593	10,372	\$1,505,272	\$16,820,200	18
Greater than 50	monthly	799	9,588	\$837,847	\$9,684,130	16
Total	-	4,457	21,025	\$2,774,416	\$31,811,730	36
All Tanks						
6 to 12 TPY	annually	1,413	1,413	\$581,736	\$7,097,980	3
12 to 50 TPY	quarterly	2,921	11,684	\$1,733,480	\$19,176,120	22
Greater than 50	monthly	978	11,736	\$1,083,478	\$12,200,660	22
Total	-	5,312	24,833	\$3,398,695	\$38,474,760	47

Table 8.2: Initial Year STEM Cost Analysis, Part 2

Tank Uncontrolled VOC Emissions	Monitoring Requirement	Buffer Bottle Costs (3)	Annual Number of Leaks	Leak Repair Costs (4)	Re-monitoring Cost (5)	Total Initial Year STEM Costs for Tanks (1+2+3+4+5)	Per Tank Cost for Initial Year
Crude Oil Tanks							
6 to 12 TPY	annually	\$134,545	15	\$1,950	\$1,783	\$261,672	\$11,377
12 to 50 TPY	quarterly	\$29,248.83	13	\$1,696	\$1,550	\$67,398	\$13,480
Greater than 50	monthly	\$81,897	109	\$14,244	\$13,023	\$302,525	\$21,609
Total	-	\$245,690	136	\$17,890	\$16,357	\$631,595	\$15,038
Attainment Area Condensate Tanks							
6 to 12 TPY	annually	\$1,901,174	210	\$27,556	\$33,592	\$3,779,946	\$11,631
12 to 50 TPY	quarterly	\$1,889,474	835	\$109,545	\$133,541	\$4,681,786	\$14,495
Greater than 50	monthly	\$965,211	1,279	\$167,879	\$204,653	\$3,906,544	\$23,676
Total	-	\$4,755,859	2,324	\$304,981	\$371,786	\$12,368,276	\$15,213
Non-Attainment Area Condensate Tanks							
6 to 12 TPY	annually	\$6,230,000	688	\$90,299	\$82,559	\$12,141,554	\$11,401
12 to 50 TPY	quarterly	\$15,168,441	6,700	\$879,416	\$804,037	\$35,177,366	\$13,566
Greater than 50	monthly	\$4,673,962	6,194	\$812,943	\$743,262	\$16,752,144	\$20,966
Total	-	\$26,072,403	13,582	\$1,782,657	\$1,629,858	\$64,071,064	\$14,375
All Tanks							
6 to 12 TPY	annually	\$8,265,719	\$913	\$119,805	\$117,934	\$16,183,172	\$11,453
12 to 50 TPY	quarterly	\$17,087,164	\$7,548	\$990,657	\$939,128	\$39,926,550	\$13,669
Greater than 50	monthly	\$5,721,070	\$7,582	\$995,066	\$960,938	\$20,961,213	\$21,433
Total	-	\$31,073,952	\$16,042	\$2,105,528	\$2,018,001	\$77,070,935	\$14,509

As a result of initial implementation of a LDAR program, it has been shown that leak frequencies decrease from 1.7 percent to 0.4 percent (Trihydro 2014). Therefore, in subsequent years, the number of leaks was adjusted to reflect the reduced leak frequency. The reduced leak repair and re-monitoring costs with the adjusted number of leaks were estimated and shown in table 9. It is assumed that subsequent LDAR and AVO capital (annualized), recurring annual, and annualized buffer bottle costs would remain as estimated in the initial year (table 8), while the number of repairs and re-monitoring needed would fall as the leak rate frequency also falls in subsequent years (table 9). The total STEM costs for subsequent years, shown in table 9, include the capital, inspection and O&M costs, and buffer bottle costs in table 8, with the adjusted leak repair and re-monitoring costs in table 9.

Table 9: Subsequent Year STEM Cost Analysis

Tank Uncontrolled VOC Emissions	Monitoring Requirement	Number of Storage Tanks and Crude Oil Tanks	Annual Number of Leaks	Leak Repair Costs (4)	Re-monitoring Cost (5)	Total Subsequent Year STEM Costs for Tanks (Annual Cost) (1+2+3+4+5)	Per Tank Cost in Subsequent Years (Annual Cost)
Crude Oil Tanks							
6 to 12 TPY	annually	23	3	\$459	\$420	\$258,817	\$11,253
12 to 50 TPY	quarterly	5	3	\$399	\$365	\$64,915	\$12,983
Greater than 50	monthly	14	26	\$3,352	\$3,064	\$281,673	\$20,120
Total	-	42	32	\$4,209	\$3,849	\$605,406	\$14,414
Attainment Area Condensate Tanks							
6 to 12 TPY	annually	325	49	\$6,484	\$7,904	\$3,733,186	\$11,487
12 to 50 TPY	quarterly	323	196	\$25,775	\$31,421	\$4,495,896	\$13,919
Greater than 50	monthly	165	301	\$39,501	\$48,154	\$3,621,666	\$21,949
Total	-	813	547	\$71,760	\$87,479	\$11,850,749	\$14,577
Non-Attainment Area Condensate Tanks							
6 to 12 TPY	annually	1,065	162	\$21,247	\$19,426	\$12,009,369	\$11,276
12 to 50 TPY	quarterly	2,593	1,577	\$206,921	\$189,185	\$33,890,019	\$13,070
Greater than 50	monthly	799	1,457	\$191,281	\$174,885	\$15,562,105	\$19,477
Total	-	4457	3,196	\$419,449	\$383,496	\$61,461,493	\$13,790
All Tanks							
6 to 12 TPY	annually	1,413	214	28,190	27,750	\$16,001,372	\$11,324
12 to 50 TPY	quarterly	2,921	1,776	233,095	220,971	\$38,450,830	\$13,164
Greater than 50	monthly	978	1,784	234,134	226,103	\$19,465,444	\$19,903
Total	-	5,312	3,775	495,418	474,824	\$73,917,648	\$13,915

To better understand the costs per ton of VOCs reduced across the different levels of uncontrolled emissions, Louis Berger queried data from the APEN database provided by the Division to identify the uncontrolled emissions for the various tanks which is summarized in table 10.⁵

⁵ The following Exhibits were analyzed on the state's rulemaking ftp site: APCD-PHS EX TT (produced water tanks), APCD-PHS-EX-LL (condensate tanks), APCD -PHS- EX - MM (crude oil tanks), APCD-PHS EX- (STEM emission control).

Table 10: Uncontrolled Emissions for Tanks

Tank Uncontrolled VOC Emissions	Monitoring frequency	Number of storage tanks and crude oil tanks	Uncontrolled VOC emissions per tank (TPY)	Total uncontrolled VOC emissions (TPY)
Crude Oil Tanks				
6 to 12 TPY	annually	23	8.70	200
12 to 50 TPY	quarterly	5	25.80	129
Greater than 50	monthly	14	268.63	3,760
Total	-	42	97.38	4,090
Attainment Area Condensate Tanks				
6 to 12 TPY	annually	325	8.62	2,802
12 to 50 TPY	quarterly	323	22.41	7,237
Greater than 50	monthly	165	156.01	25,742
Total	-	813	44.01	35,781
Non-Attainment Area Condensate Tanks				
6 to 12 TPY	annually	1,065	8.77	9,341
12 to 50 TPY	quarterly	2,593	26.15	67,797
Greater than 50	monthly	799	135.99	108,656
Total	-	4,457	41.69	185,794

The approach used by Louis Berger for the initial emission reductions (year 1) is very similar to that of the Division's: the uncontrolled emissions less the control for the flares (71.25%) or 0.2876 percent of the uncontrolled emissions, times 95 percent. *Note that the Division's efficiency rate for the flare and auto-igniter of 71.25 percent is not supported by empirical data or industry literature, nor is it consistent with EPA guidance regarding the estimated effectiveness of such control requirements for air quality planning purposes⁶. These sources would suggest that the control efficiency of flares is considerably higher than the estimates by the Division, and the effectiveness of such control requirements is also higher (83% under EPA's noted revised rule effectiveness guidance, not 75%). As such, the emission reductions attributed to STEM in this analysis (as well as in the Division's analysis) are likely overestimated. The cost per ton of VOC reduced associated with STEM are therefore likely to be higher than estimated in this analysis due to the higher efficiency factor of the flare, with fewer fugitive emissions to capture with STEM.*

The initial year results reveal an average of \$1,250 per ton of VOC reduced. Emission reductions in subsequent years are much smaller than initial reductions, especially with leak definitions as low as 500 and 2,000 PPM. The Clearstone study has indicated that annual leak detection and monitoring emissions factors result in a net reduction of 75.3 percent compared to what would occur without instrument monitoring.⁷ This is consistent with Trihydro's estimated drop in leak rate frequencies after quarterly LDAR from 1.7 percent to 0.4 percent (Trihydro 2014). Louis Berger assumed that the emissions

⁶ Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations, Appendix B, Doc.No. EPA-454/R-05-001 (August 2005).

⁷ See Clearstone Engineering study previously cited, page 19.

reductions captured in subsequent years would be consistent with this decline in leak frequency. For example, if STEM was assumed to reduce emissions by 100 TPY in the initial year, the subsequent emissions reductions would be 23.5 percent (0.4/1.7) of the initial reduction.

It should be noted that the smaller tanks incur significantly larger costs per ton of VOC reduced. In the initial year, these costs per ton are \$4,800 for tanks between 6 and 12 TPY uncontrolled emission, while tanks above 50 TPY, the initial year cost is \$555 per ton reduced. Across all tanks, the subsequent year cost per ton of VOC reduced is approximately **four times as high** as the initial year cost, with the average cost in the subsequent years of \$5,097 per ton of VOC reduced compared to the initial year cost per ton of VOC reduced of \$1,250. This is due primarily to the effectiveness of the initial year LDAR in reducing fugitive emissions to a quarter of initial year rate. Despite the relatively higher travel and inspection costs in the attainment area, since the non-attainment area is where the overwhelming majority of tanks are located, there is not a considerable difference in the cost per ton of VOC reduced between these two geographic regions. However, as shown in Table 9, the tank STEM costs are more than \$1,000 higher for attainment area tanks when compared to non-attainment tanks (for all tank uncontrolled emissions). Table 11 shows the initial year and subsequent total costs, emission reductions, and costs per ton of VOC reduced.

Figure 1 shows how the emission reductions decline after the initial year while LDAR costs per ton of VOC increase after the initial years. This figure also demonstrates the disparity in costs for facilities with different levels of uncontrolled emissions, with the lower emitting tanks having a much higher cost per ton of VOC reduced than higher emitting tanks. Over time, STEM for the tanks with the smallest uncontrolled emissions control the least amount of VOC emissions with the highest cost per ton of VOC (\$20,172), while STEM for the tanks with the highest uncontrolled emissions capture the greatest amount of emissions and have the lowest cost per ton of VOC reduced (\$2,192).

Table 11: STEM Costs Per Ton of VOC Reduced

Tank Uncontrolled VOC Emissions	STEM Costs	Emission Reduction from STEM	STEM Cost Per Ton of VOC Reduced	Annual STEM Costs	Emission Reductions	Recurring Annual Cost Per Ton of VOC Reduced
	Initial Year			Subsequent Years		
Crude Oil Tanks						
6 to 12 TPY	\$261,672	55	\$4,786	\$258,817	13	\$20,120
12 to 50 TPY	\$67,398	35	\$1,913	\$64,915	8	\$7,831
Greater than 50	\$302,525	1,027	\$295	\$281,673	242	\$1,165
Total	\$631,595	1,117	\$565	\$605,406	263	\$2,303
Attainment Area Condensate Tanks						
6 to 12 TPY	\$3,779,946	765	\$4,939	\$3,733,186	180	\$20,732
12 to 50 TPY	\$4,681,786	1,977	\$2,369	\$4,495,896	465	\$9,667
Greater than 50	\$3,906,544	7,031	\$556	\$3,621,666	1,654	\$2,189
Total	\$12,368,276	9,773	\$1,266	\$11,850,749	2,299	\$5,154
Non-Attainment Area Condensate Tanks						
6 to 12 TPY	\$12,141,554	2,551	\$4,759	\$12,009,369	600	\$20,006
12 to 50 TPY	\$35,177,366	18,517	\$1,900	\$33,890,019	4,357	\$7,778
Greater than 50	\$16,752,144	29,677	\$564	\$15,562,105	6,9823	\$2,229
Total	\$64,071,064	50,745	\$1,263	\$61,461,493	11,940	\$5,148
Total Tanks						
6 to 12 TPY	\$16,183,173	3,371	\$4,800	\$16,001,372	793	\$20,172
12 to 50 TPY	\$39,926,549	20,529	\$1,945	\$38,450,830	4,830	\$7,960
Greater than 50	\$20,961,213	37,735	\$555	\$19,465,444	8,879	\$2,192
Total	\$77,070,935	61,635	\$1,250	\$73,917,648	14,502	\$5,097

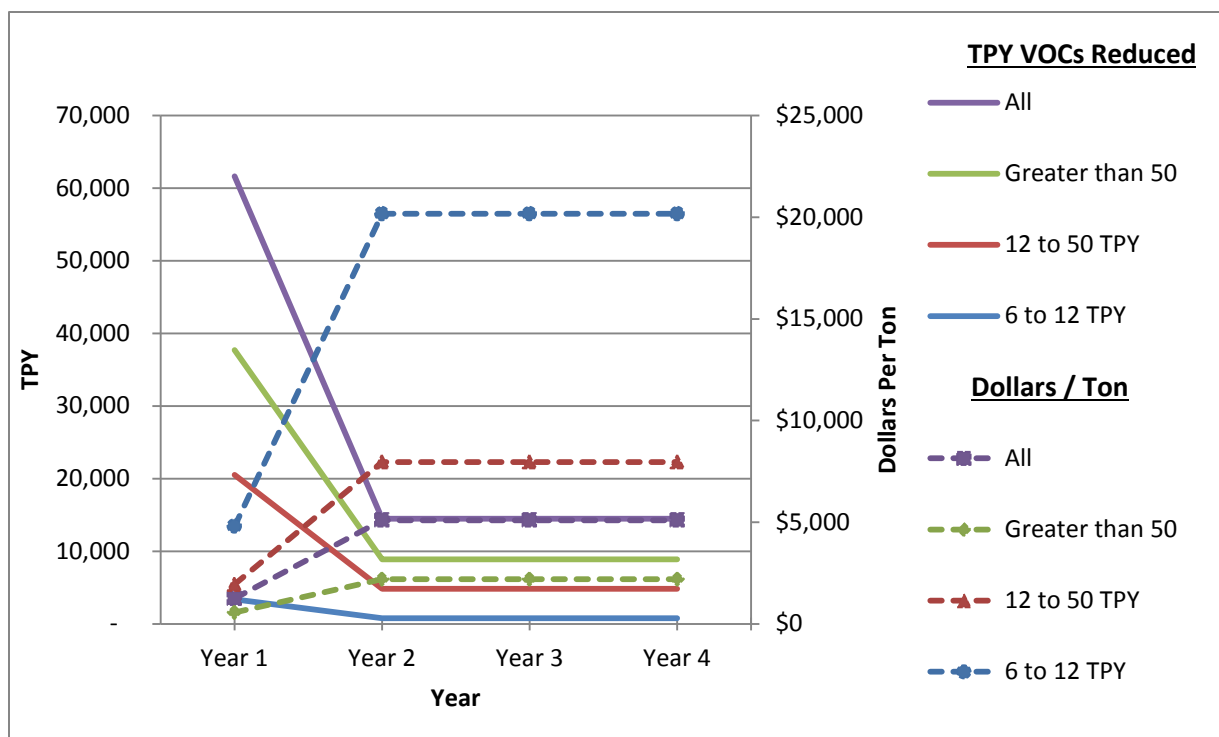


Figure 1: STEM Costs and Emission Reductions Over Time

Leak Detection and Repair Requirements for Well Production Facilities

The Division's proposed regulations include leak detection and repair requirements for well production facilities. The Division has based the LDAR monitoring frequency associated with these facilities on the uncontrolled VOC emissions with associated tanks. However, the Division's well production facility data (Exhibit RR) indicates that the tank VOC uncontrolled emissions do not correlate with fugitive emissions from well production facilities. The correlation coefficient is 0.19 indicating a weak positive correlation among the well production facilities and tank VOC uncontrolled emissions. For example, one tank had uncontrolled VOC emissions of 1,000 TPY, while the well production facilities accompanying the tank had a reported 2.4 TPY of VOC uncontrolled emissions. Regardless, the Division is requiring LDAR monitoring at various frequencies based on tank VOC uncontrolled emissions levels, and this section provides an estimate of the costs of these requirements to industry.

Louis Berger estimated LDAR inspection costs for well production facilities with a similar approach as described above for tanks. The Division has indicated that well production facilities would take on average 4.75 hours to inspect, which is consistent with Louis Berger's estimate of two facilities could be inspected per day in the non-attainment area. However, it is assumed that facilities in the attainment area would require an additional hour for travel time due to more remote operations and greater distance to access operations. Table 12 summarizes these assumptions for well production facilities.

Table 12: Well Production Facility LDAR Cost Assumptions (2013\$)

Item	LDAR			AVO		
	Estimated Cost	Annualized*	Unit Cost	Estimated Cost	Annualized*	Unit Cost
Capital and Non-Recurring Costs						
Camera	\$122,000	\$28,179	\$70.45/inspection in the AA and NAA			
Vehicle	\$30,000	\$6,929	\$17.32/inspection in the AA and NAA			
Program set up costs (i.e., Tagging, software, travel, etc.)	\$1,000	\$231	\$231/WPF	\$500	\$115.49	\$115.49/WPF
Inspection, Operations and Maintenance costs						
<i>Assume one camera can inspect 2 well production facilities a day in the AA and NAA, 400 WPF/year; 10 weeks for repair and training. Assume monthly inspections for all tanks between 6 and 50 TPY.</i>						
Inspection Labor, including travel time						
Hourly Rate:	\$150		\$150/hour	\$100		\$100/Hour
Inspection and Travel Time (NAA)	4.75		4.75 hours	.5		0.5 Hours
Inspection and Travel Time (AA)	5.75		5.75 hours	.5		0.5 Hours
Camera/Inspection training	\$7,500		Per 100 WPF	\$7,500		\$7,500/100 WPF/year
Camera repair	\$12,500		Camera			\$12,500/camera/year
Travel and per diem costs (NAA Condensate and Crude Oil)	\$30		Inspection			\$30/inspection
Travel and per diem costs (AA Condensate)	\$40					\$40/inspection
Supervision	\$100 (annual, quarterly) \$200 (monthly)		WPF			\$100/WPF/year \$200/WPF/year
Compiling data, record-keeping and reporting	\$1,530 (annual, quarterly) \$3,060 (monthly)		WPF			\$1,530/WPF/year \$3,060/WPF/year

*Camera and set up costs annualized at 5% over 5 year-life of the equipment.

Similar to the storage tank analysis, data on costs to repair components for well production facilities were obtained from Nelson and Brown (2012).⁸ The initial and subsequent year leak frequency rates were assumed to be 1.7 percent and 0.4 percent, respectively, consistent with the Trihydro report (2014) and Clearstone Engineering (2013) study. The number of components was consistent with the

⁸ Nelson, Bradley and Heather Brown. 2012. Equipment Leak Emission Reduction and Cost Analysis for Well Pads, Gathering and Boosting Stations, and Transmission and Storage Facilities Use Emission and Cost Data from the Uniform Standards. Memorandum to Greg Nizich and Bruce Moore, EPA. April. See attachments 3 and 4.

analysis in the EPA technical memorandum, based on the well pad model plant 2, with an average number of components of 592.⁹ As shown in the Division's analysis of its 40 well production facilities (Exhibit RR), the uncontrolled emissions of the tanks do not correlate with the components and uncontrolled emissions of the well production facilities. Additionally, information on 40 well production facilities does not provide a representative sample of well production facilities across the state, accounting for facilities in only five counties. As a result, without further information on the well production facilities, we used a constant number of components and uncontrolled emissions factors for all the well production facilities based on the EPA technical report (2011), consistent with information obtained from communications with industry representatives.

LDAR costs for well production facilities for the first year were estimated by Louis Berger using the approach described above to be \$136.7 million, of which 81 percent of the cost is attributed to well production facilities in the non-attainment area. For each of the various tank uncontrolled emissions levels, the costs per well production facility are greater in the attainment area when compared to those in the non-attainment area. However, when averaged across all the facilities, since there are more higher cost tanks (in the 12-50 TPY and over 50 TPY) in the non-attainment area than in the attainment area, the per well production facility cost is actually higher in the non-attainment area. The LDAR costs are summarized in Tables 13.1 and 13.2.

⁹ EPA. 2011. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Technical Support Document for Proposed Standards. See Table 8.3.

Table 13.1: Well Production Facility LDAR Cost Analysis for the Initial Year, Part 1

Tank Uncontrolled VOC Emissions	Monitoring Requirement	Number of WPF	Number of inspections/ Year	Capital Costs for Inspections (annualized) (1)	Annual Costs for Inspections (2)	Number of Cameras Needed
Attainment Area WPF						
Less than 6 TPY	One-time and monthly AVO	849	849	\$368,662	\$2,854,293	2
6 to 12 TPY	annually	328	328	\$142,428	\$1,105,560	1
12 to 50 TPY	quarterly	324	1,296	\$226,003	\$1,994,460	3
Greater than 50	monthly	169	2,028	\$236,549	\$2,456,385	5
Total	-	1,670	4,501	\$973,641	\$8,410,698	11
Non-Attainment WPF						
Less than 6 TPY	One-time and monthly AVO	1,986	1986	\$862,381	\$6,363,085	5
6 to 12 TPY	annually	1,085	1,085	\$471,140	\$3,479,663	3
12 to 50 TPY	quarterly	2,597	10,388	\$1,811,512	\$14,348,800	26
Greater than 50	monthly	809	9,708	\$1,038,928	\$8,900,035	25
Total	-	6,477	23,167	\$4,183,961	\$33,091,583	59
All WPF						
Less than 6 TPY	One-time and monthly AVO	2,835	2,835	\$1,231,043	\$9,217,378	7
6 to 12 TPY	annually	1,413	1,413	\$613,568	\$4,585,223	4
12 to 50 TPY	quarterly	2,921	11,684	\$2,037,515	\$16,343,260	29
Greater than 50	monthly	978	11,736	\$1,275,477	\$11,356,420	30
Total	-	8,147	27,668	\$5,157,602	\$41,502,281	70

Table 13.2: Well Production Facility LDAR Cost Analysis, Part 2

Tank Uncontrolled VOC Emissions	Monitoring Requirement	Annual Number of Leaks	Leak Repair Costs (3)	Re-monitoring Cost (4)	Total Initial Year LDAR Costs for WPF (1+2+3+4)	Per WPF Cost for Initial Year
Attainment Area WPF						
Less than 6 TPY	One-time and monthly AVO	8,544	\$1,121,444	\$1,927,816	\$6,272,214	\$7,388
6 to 12 TPY	annually	3,301	\$433,255	\$744,786	\$2,426,029	\$7,396
12 to 50 TPY	quarterly	13,043	\$1,711,886	\$2,942,814	\$6,875,164	\$21,220
Greater than 50	monthly	20,410	\$2,678,785	\$4,604,959	\$9,957,162	\$58,918
Total	-	45,298	\$5,945,371	10,220,376	\$25,530,568	\$15,288
Non-Attainment Area WPF						
Under 6 TPY	One-time and monthly AVO	19,987	\$2,623,307	\$3,710,106	\$13,558,880	\$6,827
6 to 12 TPY	annually	10,919	\$1,433,177	\$2,026,921	\$7,410,900	\$6,830
12 to 50 TPY	quarterly	104,545	\$13,721,509	\$19,406,134	\$49,287,955	\$18,979
Greater than 50	monthly	97,701	\$12,823,297	\$18,135,806	\$40,898,067	\$50,554
Total	-	233,153	\$30,601,290	\$43,278,968	\$111,155,802	\$17,162
All WPF						
Under 6 TPY	One-time and monthly AVO	28,531	\$3,744,751	\$5,637,922	\$19,831,094	\$6,995
6 to 12 TPY	annually	14,220	\$1,866,432	\$2,771,707	\$9,836,929	\$6,962
12 to 50 TPY	quarterly	117,588	\$15,433,395	\$22,348,948	\$56,163,119	\$19,227
Greater than 50	monthly	118,111	\$15,502,082	\$22,740,765	\$50,855,229	\$51,999
Total	-	278,451	\$36,546,661	\$53,499,344	\$136,686,370	\$16,778

Similar to the storage tank STEM analysis, following the initial implementation of a LDAR program, leak frequencies decrease, and as a result, the number of leaking components also decrease along with repair and re-monitoring costs, when compared to the initial year. Therefore, in subsequent years, the number of leaks was adjusted to reflect the reduced leak frequency (0.4%). As a result, reduced leak repair and re-monitoring costs with the adjusted number of leaks were estimated and shown in table 14. The total LDAR costs for subsequent years include the capital, and inspection and O&M costs in table 13 with the adjusted leak repair and re-monitoring costs in table 14. The exception is for well production facilities with tanks less than 6 TPY, which have been adjusted to include costs for a one-time LDAR inspection and monthly AVO.

Table 14: Subsequent Year LDAR Cost Analysis for Well Production Facilities

Tank Uncontrolled VOC Emissions	Monitoring Requirement	Number of Well Production Facilities	Annual Number of Leaks	Leak Repair Costs (3)	Re-monitoring Cost (4)	Total Subsequent Year LDAR Costs for WPF (Annual Cost) (1+2+3+4)	Per WPF Cost in Subsequent Years (Annual Cost)
Attainment Area Well Production Facilities							
Less than 6 TPY	One-time with monthly AVO	849	4,021	\$263,869	\$0	\$892,542	\$1,051
6 to 12 TPY	annually	328	777	\$101,942	\$175,244	\$1,525,174	\$4,650
12 to 50 TPY	quarterly	324	3,069	\$402,797	\$692,427	\$3,315,687	\$10,234
Greater than 50	monthly	169	4,802	\$630,302	\$1,083,520	\$4,387,239	\$25,960
Total	-	1,670	12,669	\$1,662,780	\$2,858,398	\$10,120,642	\$6,060
Non-Attainment Area Well Production Facilities							
Less than 6 TPY	One-time with monthly AVO	1,986	9,406	\$617,249	\$0	\$2,087,856	\$1,051
6 to 12 TPY	Annually	1,085	2,569	\$337,218	\$476,923	\$4,764,943	\$4,392
12 to 50 TPY	quarterly	2,597	24,599	\$3,228,590	\$4,566,149	\$23,955,051	\$9,224
Greater than 50	monthly	809	22,989	\$3,017,246	\$4,267,248	\$17,223,458	\$21,290
Total	-	6,477	59,562	\$6,583,055	\$11,056,253	\$48,031,308	\$7,416
All Well Production Facilities							
Less than 6 TPY	One-time with monthly AVO	2,835	13,427	\$881,118	\$0	\$2,980,398	\$1,051
6 to 12 TPY	Annually	1,413	3,346	\$439,160	\$652,167	\$6,290,117	\$4,452
12 to 50 TPY	quarterly	2,921	27,668	\$3,631,387	\$5,258,576	\$27,270,738	\$9,336
Greater than 50	monthly	978	27,791	\$3,647,549	\$5,350,768	\$21,610,697	\$22,097
Total	-	8,147	72,231	\$8,245,834	\$13,914,651	\$58,151,950	\$7,138

To better estimate the potential uncontrolled emissions from these facilities, uncontrolled emission factors from the well pad model number 2 were used from the EPA technical document.¹⁰ As described above, the tank uncontrolled emissions factors do not correlate with uncontrolled emissions associated with the well production facilities.¹¹ Additionally, the Division has utilized a very small sample of the well production facilities in the state for its analysis. As a result, Louis Berger used the VOC uncontrolled emissions per well production facility of 2.56 TPY associated with well pad model number 2 (592 components), which we believe more accurately reflects the types of facilities operating in Colorado based on communication with industry representatives. Table 15 summarizes the uncontrolled emissions for well production facilities.

¹⁰ See EPA (2011) previously cited, tables 8-2, 8-3, and 8-10.

¹¹ See Division's analysis of 40 well production facilities in Exhibit RR in the rulemaking documents.

Table 15: Uncontrolled Emissions for Well Production Facilities

Uncontrolled VOC Emissions for Well Production Facilities	Monitoring Frequency	Number of Well Production Facilities	Uncontrolled VOC Emissions per Well Production Facility (TPY)	Total Uncontrolled VOC Emissions (TPY)
WPF in the Attainment Areas				
Less than 6 TPY	One time and AVO	849	2.560	2,173
6 to 12 TPY	annually	328	2.560	840
12 to 50 TPY	quarterly	324	2.560	829
Greater than 50	monthly	169	2.560	433
Total	-	1,670	-	4,275
WPF in the Non-Attainment Area				
Less than 6 TPY	One time and AVO	1,986	2.560	5,084
6 to 12 TPY	annually	1,085	2.560	2,778
12 to 50 TPY	quarterly	2,597	2.560	6,648
Greater than 50	monthly	809	2.560	2,071
Total	-	6,477	-	16,581
All WPFs				
Less than 6 TPY	One time and AVO	2,835	2.560	7,257
6 to 12 TPY	annually	1,413	2.560	3,618
12 to 50 TPY	quarterly	2,921	2.560	7,477
Greater than 50	monthly	978	2.560	2,504
Total	-	8,147	-	20,856

Louis Berger again uses an approach which utilizes a Canadian study, described above, and assumes an across the board reduction of 75.3 percent of uncontrolled emissions in the initial year with a one-time and annual LDAR program. The quarterly LDAR program is assumed to reduce emissions in the initial year by 76.5, consistent with the report by Trihydro (2013), and monthly LDAR is assumed to be even more effective, reducing emissions by 80 percent in the initial year. The average initial year cost per ton of VOC reduced across all well production facilities was estimated to be \$8,590 per ton.

As with the STEM program, subsequent emission reductions in future years are expected to be much lower than in the initial year. The emission reductions in subsequent years are assumed to decline by the same proportion as the decline in leak frequency (0.4/1.7). The emission reductions were then divided by total annual costs in subsequent years to estimate the cost per ton of VOC reduced. In subsequent years, the average cost is \$19,354 per ton of VOC reduced, approximately twice the initial year cost. Since uncontrolled emissions per well production facility are assumed constant across all of the tank uncontrolled emissions levels, the costs per tons of VOC reduced increase significantly with the higher tank VOC uncontrolled emissions levels (greater than 50 TPY) as more monitoring is required of these facilities. The cost per ton of VOC reduced for well production facilities is \$45,855 in subsequent years for the greater than 50 TPY, while 12 to 20 TPY facilities incur a cost of \$20,261 per ton of VOC reduced in subsequent years.

When comparing across the geographies, the costs per ton reduced are approximately \$1,000 more in the attainment area when compared to costs in the non-attainment area. Table 16 and Figure 2 shows the initial and subsequent year total costs, emission reductions, and cost per ton of VOC reduced.

Table 16: Well Production Facility LDAR Cost per Ton of VOC Reduced

Tank Uncontrolled VOC Emissions	LDAR Costs	Emission Reduction from LDAR	LDAR Cost Per Ton of VOC Reduced	Annual LDAR Costs	Emission Reductions with LDAR	Recurring LDAR Annual Cost Per Ton of VOC Reduced
	Initial Year			Subsequent Years		
Attainment Area WPF						
Less than 6 TPY	\$6,272,214	1,637	\$3,832	\$892,542	164	\$5,454
6 to 12 TPY	\$2,426,029	632	\$3,837	\$1,525,174	149	\$10,252
12 to 50 TPY	\$6,875,164	635	\$10,835	\$3,315,687	149	\$22,208
Greater than 50	\$9,957,162	346	\$28,769	\$4,387,239	81	\$53,872
Total	\$25,530,568	3,250	\$7,857	\$10,120,642	543	\$18,633
Non-Attainment Area WPF						
Less than 6 TPY	\$13,558,880	3,828	\$3,542	\$2,087,856	383	\$5,454
6 to 12 TPY	\$7,410,900	2,092	\$3,543	\$4,764,943	492	\$9,682
12 to 50 TPY	\$49,287,955	5,086	\$9,691	\$23,955,051	1,197	\$20,018
Greater than 50	\$40,898,067	1,657	\$24,684	\$17,223,458	390	\$44,181
Total	\$111,155,802	12,663	\$8,778	\$48,031,308	2,462	\$19,513
Total WPF						
Less than 6 TPY	\$19,831,094	5,465	\$3,629	\$2,980,398	547	\$5,454
6 to 12 TPY	\$9,836,929	2,724	\$3,611	\$6,290,117	641	\$9,815
12 to 50 TPY	\$56,163,119	5,720	\$9,818	\$27,270,738	1,346	\$20,261
Greater than 50	\$50,855,229	2,003	\$25,390	\$21,610,697	471	\$45,855
Total	\$136,686,370	15,913	\$8,590	\$58,151,950	3,005	\$19,354

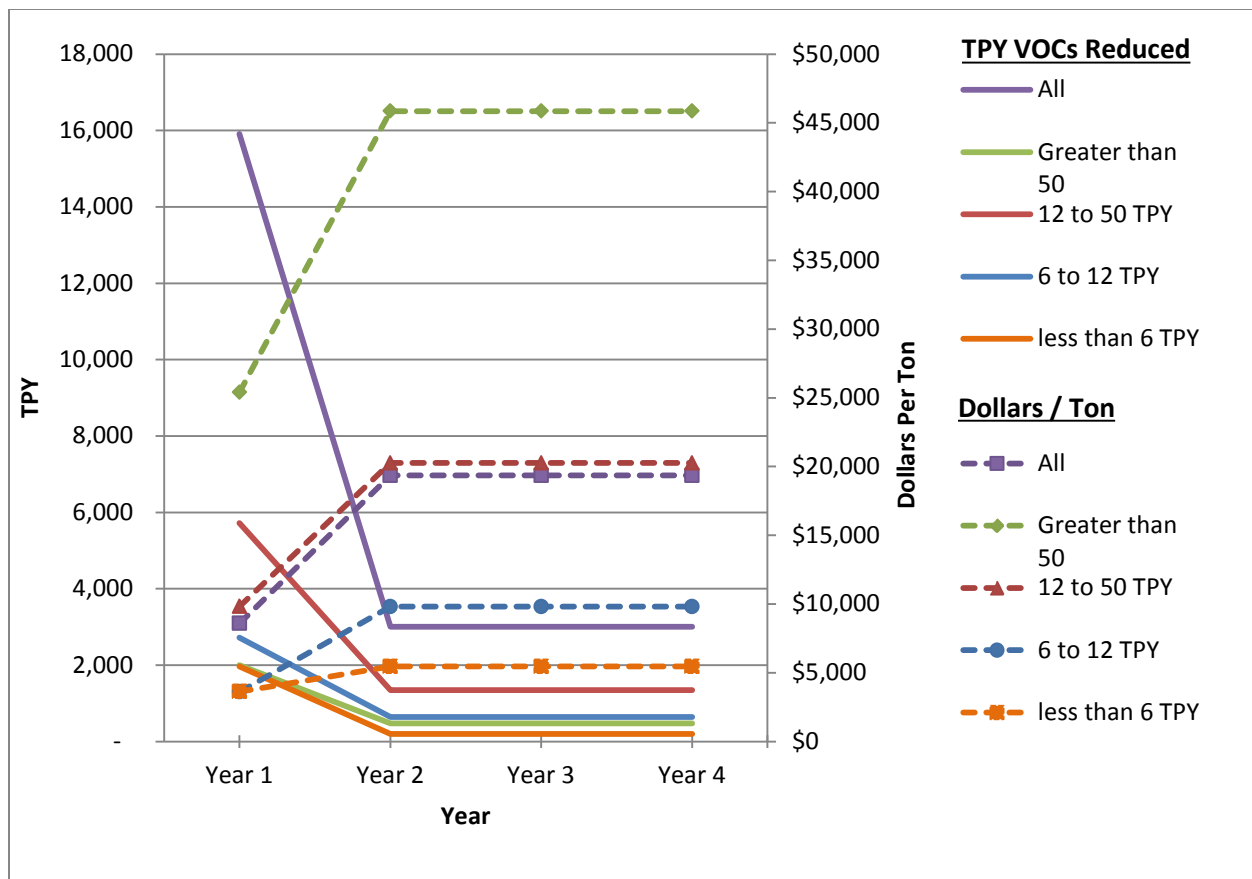


Figure 2: Well Production Facilities LDAR Costs and Emission Reductions Over Time

LDAR Costs for Compressor Stations

Louis Berger estimated LDAR costs for compressor stations with a similar approach as described above using the Division's estimates of the number of compressor stations affected by the proposed regulations. Louis Berger assumed two and four days per inspection for small and large compressor stations, respectively. Table 17 summarizes these assumptions.

Table 17: Compressor Station LDAR Cost Assumptions (2013\$)

Item	Estimated Cost	Annualized*	Unit Cost
Capital and Non-Recurring Costs			
Camera	\$122,000	\$28,179	\$282 per inspection for small CS and \$564 for large CS
Vehicle	\$30,000	\$6,929	\$69 per inspection for small CS and \$139 for large CS
Program set up costs (i.e., Tagging, software, travel, etc.)	\$13,688 for small compressor stations, and \$27,272 for large CS	\$1,319 for small CS and \$2,627 for large CS	\$1,319/small CS and \$2,627/large CS
Assume inspections would take 2 days to inspect for smaller facilities, 100 inspections with one camera per year; inspections would take 4 days for larger facilities, 50 inspections with one camera per year.			
Inspection, Operations and Maintenance costs			
Small CS with Annual LDAR	\$6,468		\$6,468/year/CS
Large CS with Quarterly LDAR	\$32,683		\$32,683/year/CS
Travel and per diem costs	\$32		\$32/Inspection
Supervision	\$200		\$200/CS
Camera Repair	\$12,500		\$12,500/year/camera
Camera Training	\$7,500		\$7,500 per 100 CS
Record-keeping and reporting of comments	\$1,530 for small CS \$3,060 for large CS		\$1,540/small CS \$3,060/large CS

*Camera and vehicle costs annualized at 5% over 5 year-life of the equipment. Program set up costs are annualized over 15 years at 5%.

Similar to the previous analysis, data on costs to repair components were obtained from Nelson and Brown (2012).¹² The initial year leak frequency rate was assumed to be 1.17 percent, consistent with the Trihydro study (2014). The number of components was assumed to be 2,544 for small compressor stations and 6,744 for large compressor stations. Cost assumptions for repairs and re-monitoring are similar to those described above.

Tables 18.1 and 18.2 summarize the LDAR costs for compressor stations. LDAR costs for 200 compressor stations were estimated to be \$15.4 million. Small compressor stations are estimated to incur \$26,353 per facility in the initial year, while larger compressor stations would incur \$217,599 per facility in the initial year.

¹² Nelson, Bradley and Heather Brown. 2012. Equipment Leak Emission Reduction and Cost Analysis for Well Pads, Gathering and Boosting Stations, and Transmission and Storage Facilities Use Emission and Cost Data from the Uniform Standards. Memorandum to Greg Nizich and Bruce Moore, EPA. April. See attachments 3 and 4.

Table 18.1: Compressor Stations LDAR Cost Analysis for the Initial Year, Part 1

Compressor Station Uncontrolled VOC Emissions	Monitoring Frequency	Number of Compressor Stations	Number of Inspections/ Year	Capital Costs for Inspections (annualized) (1)	O&M Annual Costs for Inspections (2)	Number of Cameras Needed
Less than 12TPY	annual	147	147	\$204,321	\$1,245,835	2
12 to 50 TPY	quarterly	53	212	\$288,112	\$1,978,238	5
Greater than 50	monthly	-	-	-	-	-
Total	-	200	359	\$492,433	\$3,224,073	7

Table 18.2: Compressor Station LDAR Cost Analysis for the Initial Year, Part 2

Compressor Station Uncontrolled VOC Emissions	Monitoring Frequency	Number of Components	Annual Number of Leaks	Leak Repair Costs (3)	Re-monitor Costs (4)	Total Annual LDAR Costs for Compressor Stations (1+2+3+4)	Per Compressor Station Cost, Initial Year
Less than 12	annual	2,544	6,357	\$834,416	\$1,589,364	\$3,873,936	\$26,353
12 to 50 TPY	quarterly	6,744	24,305	\$3,190,081	\$6,076,344	\$11,532,775	\$217,599
Greater than 50	monthly	-	-	\$0	\$0	\$0	-
Total	-	9,288	30,663	\$4,024,497	\$7,665,708	\$15,406,710	\$77,033

Similar to the storage tank STEM analysis, following the initial implementation of a LDAR program, leak frequencies decrease, and as a result, the number of leaking components also decrease along with repair and re-monitoring costs, when compared to the initial year. Therefore, in subsequent years, the number of leaks was adjusted to reflect the reduced leak frequency (0.4%). As a result, reduced leak repair and re-monitoring costs with the adjusted number of leaks were estimated and shown in table 19. The total LDAR costs for subsequent years include the capital, and inspection and O&M costs in table 18 with the adjusted leak repair and re-monitoring costs in table 19.

Table 19: Compressor Station LDAR Cost Analysis for Subsequent Years

Compressor Stations Uncontrolled VOC Emissions	Monitoring Frequency	Number of Components	Annual Number of Leaks	Leak Repair Costs (3)	Re-monitor Costs (4)	LDAR Costs for Compressor Stations in Subsequent Years (Annual Cost) (1+2+3+4)	Per Compressor Station Cost, Subsequent Years
Less than 12	annual	2,544	1,496	\$196,333	\$373,968	\$2,020,457	\$13,745
12 to 50 TPY	quarterly	6,744	5,719	\$750,607	\$1,429,728	\$4,446,685	\$83,900
Greater than 50	monthly	-	-	-	-	-	-
Total	-	9,288	7,215	\$946,940	\$1,803,696	\$6,467,142	\$32,336

The Division has identified an average uncontrolled emission rate for compressor stations of 10.1 TPY of VOCs for small compressor stations and 16.4 for large compressor stations, respectively. Louis Berger used these assumptions for uncontrolled emissions for the analysis as summarized in Table 20.

Table 20: Uncontrolled Emissions for Compressor Stations

Compressor Stations Uncontrolled VOC Emissions	Monitoring Frequency	Number of Compressor Stations	Uncontrolled VOC Emissions per Compressor Station (TPY)	Total Uncontrolled VOC Emissions (TPY)
Less than 12 TPY	annual	147	10.1	1,485
12 to 50 TPY	quarterly	53	16.4	869
Greater than 50	monthly	-	-	-
Total	-	200	-	2,354

Similar to the analyses on storage tanks and well production facilities, Louis Berger again uses the emission reductions associated with annual LDAR from the Clearstone Engineering, Ltd. study, described above, which estimates 75.3 percent emissions reductions associated with the annual LDAR program. Quarterly LDAR monitoring is assumed to be slightly more effective, reducing emissions by 76.5 percent, consistent with declining leak frequencies documented in the Trihydro report (2014).

As with tanks and well production facilities, Louis Berger accounts for subsequent year emission reductions with LDAR for compressor stations. The emission reductions in subsequent years are assumed to decrease by the proportion based on the reduction in leak frequency (0.4/1.7). The subsequent year costs were then divided by emission reductions in subsequent years to estimate the cost per ton of VOC reduced. Initial year cost per ton of VOC reduced is \$8,641, while in subsequent years, the cost per ton of VOC reduced increases to \$15,416. Table 21 shows the initial year and subsequent year total costs, emission reductions, and cost per ton of VOC reduced.

Table 21: Compressor Station LDAR Cost per Ton of VOC Reduced in Initial and Subsequent Years

Compressor Stations VOC Uncontrolled Emissions	LDAR Costs	Emissions Reductions	Cost Per Ton of VOC Reduced	Annual LDAR Costs	Emission Reductions	Annual Cost Per Ton of VOC Reduced
	Initial Year			Subsequent Years		
Less than 12 TPY	\$3,873,936	1,118	\$3,465	\$2,020,457	263	\$7,681
12 to 50 TPY	\$11,532,775	665	\$17,344	\$4,446,685	156	\$28,421
Greater than 50	-	-	-	-	-	-
Total	\$15,406,710	1,783	\$8,641	\$6,467,142	420	\$15,416

Expanding Low Bleed Pneumatics Requirements Statewide

The Division is proposing to expand statewide the regulatory requirements mandating the use of low bleed pneumatic controls that were adopted for the nonattainment area in 2008. This section estimates the cost of the requirement to industry.

Under the proposed rules, high-bleed pneumatic controllers shall be replaced or retrofitted with low-bleed pneumatic devices by May 1, 2015. It is assumed that the Division would define a low-bleed pneumatic device as one that emits less than or equal to 6 standard cubic feet per hour (scfh), while high-bleed devices bleed at a rate greater than 6 scfh. The Division has estimated that 9,877 high-bleed pneumatic devices are being utilized outside the nonattainment area. Louis Berger utilizes this estimate of the number of devices that will need to be replaced to comply with the proposed rule.

The EPA through their Natural Gas Star Program, has evaluated the effectiveness of reducing methane emissions through the replacement of high-bleed pneumatic devices with low-bleed pneumatics. In the document titled, "Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry", EPA provides estimates of costs, service life, benefits and decision process for determining the feasibility of replacing high-bleed pneumatics.¹³ The costs of several models of pneumatic devices are summarized in Appendix B and range from \$380 to \$3,500 in 2006 dollars. In addition, EPA reported the average cost of a low-bleed pneumatic device of \$2,553 in 2008 dollars. Based on this information, Louis Berger assumes the cost of low-bleed pneumatic devices averages \$2,775 adjusted to 2013 dollars. In addition, the analysis assumes a service life of 5 years¹⁴ and cost are annualized at a 5 percent interest rate.

Replacement of pneumatic devices would require an initial assessment of the devices used at various facilities. The EPA suggests that a system-wide or facility-specific pneumatic survey would need to record for each device "location, function, make and model, condition, age, estimated remaining useful

¹³ U.S. EPA, "Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry", October, 2006.

¹⁴ U.S. EPA, "Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry", October, 2006.

life, and bleed rate characteristics (volume and whether intermittent or continuous).”ⁱ Louis Berger has estimated the cost of conducting a pneumatic survey in the cost of the regulatory mandate as summarized in Table 22. Total cost of the mandate is estimated to be \$32 million.

Table 22: Estimated Cost of Low-Bleed Pneumatic Devices

Item	Estimated Cost	Annualized*
Capital and Non-Recurring Costs		
Low-Bleed Pneumatic Devices	\$2,775	\$641
Pneumatic Survey	\$500	\$115
Total Cost	\$3,275	\$756

*Annualized at 5% over a five year service life.

Replacing high-bleed pneumatics with low-bleed devices will likely result in gas savings and the value of these savings per device are estimated in Table 23. Payback period is estimated to be 2.8 years.

Table 23: Gas Savings Associated with Low-Bleed Pneumatic Devices

Estimated Annual Bleed Emission Reductions (Methane) (Tons) ⁱⁱ	Gas Volume (Mcf)	Gas Price (\$/Mcf)	Value of Gas Recovered
(1)	(2) = (1)*40.49 Mcf/ton	(3)	(4) = (3) * (2)
6.65	269	\$4.34	\$1,168

Recovered Product Estimates Attributable to proposed STEM and LDAR Requirements

In their analysis of cost effectiveness of LDAR requirements, the Division “...assumes that the costs savings from additional product capture will be equal or greater than the cost of repair and re-inspection.”¹⁵ In order to test the validity of this assumption, Louis Berger estimated the product savings that can be expected from LDAR requirements for well production facilities and compressor stations.

Gas Savings Attributed to LDAR – Well Production Facilities

Product savings attributable to the LDAR program as it relates to well production facilities in the initial year are estimated as shown in Table 24. Column 1 shows that 15,913 tons of VOCs are estimated to be detected and captured by the LDAR program for all well production facilities in the initial year of the program (see Table 16). Louis Berger used a Gas/VOC ratio (22.4%) reported by the Division in their analysis of LDAR costs of well production facilities to estimate the amount of gas that would be captured by the controls. In this case, 71,040 tons of gas is expected to be captured by the LDAR program at well production facilities in the initial year. The gas mass was then converted to a volume metric using a

¹⁵Colorado Air Quality Control Commission 2014. Updated Economic Impact Analysis for Proposed Revisions to AQCC Regulations Number 7. Submitted with Pre-Hearing Statement on January 6, 2014. Page 17.

natural gas density factor and results in 2,876,121Mcf of gas recovered. The value of the recovered gas was estimated at \$12.4 million for the initial year using a recent natural gas price of\$4.34 Mcf. The value of the product savings equates to 8.8 percent of the total LDAR costs (\$136 million) for the initial year of implementation.

Table 24: Product Savings Attributable to the LDAR Program for Well Production Facilities for the Initial Year

Tons of VOCs Captured by LDAR Program at WPF	Average Gas/VOC Ratio ¹	Tons of Methane Captured by LDAR Program for WPF (Tons)	Natural Gas Volume Recovered (MCF) ²	Natural Gas Price (\$/Mcf) ³	Value of Recovered Gas
(1)	(2)	(3) = (1) / (2)	(4) = (3)/0.0247 ton/mcf	(5)	(6) = (4) * (5)
15,913	22.4%	71,040	2,876,121	\$4.34	\$12,482,363

¹ Taken from the Division's calculation on LDAR costs for well production facilities. Spreadsheet titled "APCD-PHS EX-RR.xlsx"; sheet: statewide wells model FAC.

² Natural gas volumes calculated by assuming a gas density of 0.791 kg/m3 and converted to English units.

³ Henry Hub Natural Gas Spot Price for December, 2013. Obtain from the Energy Information Agency at <http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm>.

For subsequent years, the LDAR program at well production facilities is expected to realize product savings though they are expect to decline from the initial year. An estimate of the amount and value of the product saved is estimated as shown in Table 25. Using the same approach as used for the initial year, the amount of natural gas expected to be recovered in subsequent years is estimated to be 543,125 Mcf and is valued at \$2.3 million which is less than four percent of the total annual LDAR costs in subsequent years.

Table 25: Product Savings Attributable to the LDAR Program for Well Production Facilities for Subsequent Years

Tons of VOCs Captured by LDAR Program at WPF	Average Gas/VOC Ratio ¹	Tons of Methane Captured by LDAR Program for WPF (Tons)	Natural Gas Volume Recovered (MCF) ²	Natural Gas Price (\$/Mcf) ³	Value of Recovered Gas
(1)	(2)	(3) = (1) / (2)	(4) = (3)/0.0247 ton/mcf	(5)	(6) = (4) * (5)
3,005	22.4%	13,415	543,125	\$4.34	\$2,357,161

¹ Taken from the Division's calculation on LDAR costs for well production facilities. Spreadsheet titled "APCD-PHS EX-RR.xlsx"; sheet: statewide wells model FAC.

² Natural gas volumes calculated by assuming a gas density of 0.791 kg/m3 and converted to English units.

³ Henry Hub Natural Gas Spot Price for December, 2013. Obtain from the Energy Information Agency at <http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm>.

The Division's assertion that product captured and sold would offset costs of repair and re-monitoring is not supported by this analysis. Well production facility LDAR repair and re-monitoring costs in the initial year are estimated to be \$90.0 million (see table 13), while the value of the recovered gas is estimated to be \$12.4 million in the initial year, or 13.8 percent of the repair and re-monitoring cost. In subsequent years, the value of the gas recovered would offset 10.9 percent of the repair and re-monitoring costs.

Gas Savings Attributed to LDAR – Compression Stations

Gas savings attributable to the LDAR program as it relates to compressor stations in the initial year are estimated as shown in Table 26. The amount of gas that is expected to be detected and captured by a successful LDAR program at compressor stations during the initial year is 322,260 Mcf and is valued at \$1.3 million. This value represents 8.6 percent of the total cost of the LDAR program during the initial year. It is worth noting that Louis Berger believes the estimated product savings for compressor stations may be conservatively high. This opinion is based on the likelihood that the gas/VOC ratio is not as high for compressor stations as it is for well production facilities.

Table 26: Product Savings Attributable to the LDAR Program for Compressor Stations for the Initial Year

Tons of VOCs Captured by LDAR Program for Compressor Stations	Average Gas/VOC Ratio ¹	Tons of Methane Captured by LDAR Program for Compressor Stations (Tons)	Natural Gas Volume Recovered (MCF) ²	Natural Gas Price (\$/Mcf) ³	Value of Recovered Gas
(1)	(2)	(3) = (1) / (2)	(4) = (3)/0.0247 ton/mcf	(5)	(6) = (4) * (5)
1,783	22.4%	7,960	322,260	\$4.34	\$1,398,608

¹ Taken from the Division's calculation on LDAR costs for well production facilities. Spreadsheet titled "APCD-PHS EX-RR.xlsx"; sheet: statewide wells model FAC.

² Natural gas volumes calculated by assuming a gas density of 0.791 kg/m³ and converted to English units.

³ Henry Hub Natural Gas Spot Price for December, 2013. Obtain from the Energy Information Agency at <http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm>.

For subsequent years, the LDAR program at compressor stations is also expected to generate gas savings though these savings are expected to decline from the initial year. An estimate of the amount and value of the project saved is shown in Table 27. The amount of natural gas expected to be recovered in subsequent years is estimated to be 1,875Mcf and is valued at \$329,453 which represents 5 percent of total annual costs of the program in subsequent years.

Table 27: Product Savings Attributable to the LDAR Program for Compressor Stations for Subsequent Years

Tons of VOCs Captured by LDAR Program for Compressor Stations	Average Gas/VOC Ratio ¹	Tons of Methane Captured by LDAR Program for Compressor Stations (Tons)	Natural Gas Volume Recovered (MCF) ²	Natural Gas Price (\$/Mcf) ³	Value of Recovered Gas
(1)	(2)	(3) = (1) / (2)	(4) = (3)/0.0247 ton/mcf	(5)	(6) = (4) * (5)
420	22.4%	1,875	75,911	\$4.34	\$329,453

¹ Taken from the Division's calculation on LDAR costs for well production facilities. Spreadsheet titled "APCD-PHS EX-RR.xlsx"; sheet: statewide wells model FAC.

² Natural gas volumes calculated by assuming a gas density of 0.791 kg/m³ and converted to English units.

³ Henry Hub Natural Gas Spot Price for December, 2013. Obtain from the Energy Information Agency at <http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm>.

The Division's assertion that product captured and sold would offset costs of repair and re-monitoring is not supported by this analysis. Compressor station LDAR repair and re-monitoring costs in the initial year are estimated to be \$11.7 million (see table 13), while the value of the recovered gas is estimated to be \$1.4 million in the initial year, or 12.0 percent of the repair and re-monitoring cost. In subsequent years, the value of the gas recovered would also offset only 12.0 percent of the repair and re-monitoring costs.

Indirect Costs of Regulations on Small Operators and Marginally Producing Wells

In order to gain an understanding of the potential indirect costs to businesses, in particular small businesses, if the proposed rules were implemented, Louis Berger evaluated the impacts on small operators and marginally producing wells within the state. Evaluation of historical production and well count data maintained by the Colorado Oil and Gas Conservation Commission (COGCC) indicates that 25,463 conventionally completed wells produce approximately 1.57 million barrels of oil per month (BOPM) or on average two barrels of oil per day as of mid-year 2013. These marginally producing wells represent over half (55 percent) of the total producing wells in the state (46,495) as of 2013. Given the likelihood that smaller operations would be negatively impacted by the increased costs of the proposed rules and regulations as well as the large percentage of these wells that occur within the state, small and marginally producing operations are the focus of this analysis.

Louis Berger first evaluated the economic limit (in barrels per day) that marginally producing wells would realize under current economic and regulatory conditions. The economic limit is defined as the point that production levels are no longer economic given a number of factors (price of oil, lease costs, tax rates, etc.). Relevant assumptions for this analysis are as follows:

- Current Rate of Production – 2 BOPD
- Oil Price - \$90 (\$/BO)
- Severance Tax Rate – 5%

- Net Return on Investment (NRI) (well income minus royalties) – 80%
- Lease Operating Expense (\$/well/month) (includes ad valorem taxes) - \$900
- Number of Tanks per lease – 2
- Number of Wells per lease – 4
- Production Decline Rate – 2.5%

The economic limit in barrels of oil per day (BOPD) was calculated for wells using the following equation.

$$\text{Economic Limit (BOPD)} = \frac{\text{Lease Operating Expense (LOE)}}{(\text{Oil Price}) * (30.4 \text{ days}) * (\text{NRI} * (1 - \text{severance tax}))}$$

Implementation of the new air quality rules would have an impact on lease operating expenses for each well. The increase costs would change the economic limit for each well as shown in Figure 3. Under current economic and regulatory conditions, the economic limit for marginally producing wells was estimated to be 0.43 BOPD. In other words, when production falls below 0.43 BOPD, the well is no longer economic and will be shut it or plugged. If lease operating costs increase, the economic limit increases, causing wells to be shut in earlier than planned. This leads to oil left in place as shown in Figure 3.

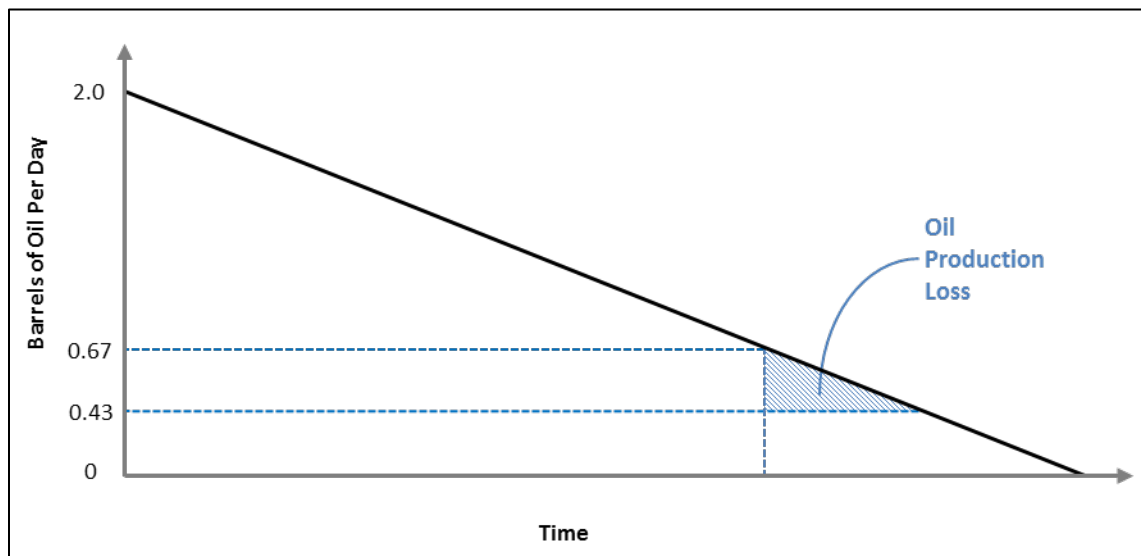


Figure 3: Oil Production Loss with an Increase in the Economic Limit

The amount of production that would result under different economic limits was calculated as follows.

$$\text{Remaining Oil} = \frac{(Q_i - Q_f) * 365}{\text{Limit} (1 - \text{Decline Rate})}$$

Where:

Q_i = Current Production Rate = 2 BOPD

Q_f = Calculated Economic Limit

Louis Berger estimated the economic limit for marginally producing wells if the air regulations relevant to oil and gas operations were implemented as proposed by the Division. The STEM costs for tanks and the LDAR costs for well production facilities were included as additional monthly unit costs in the lease operating expenses, increasing these costs for operators. The results are summarized in Table 19. Changes in lease operating costs due to the regulations were estimated for different sizes of facilities. Costs are expected to increase from \$22 to \$1,290 per month with an average of \$729 for all facilities. The increase costs are expected to increase the economic limit from 0.44 to 1.05 BOPD, depending on the size of facilities.

The additional cost burden would result in as much as 128.6 million barrels of oil being left in place and not produced over time. Assuming a price per barrel of oil is \$90, this would equate in \$11.6 billion in lost revenue to producers, \$2.3 billion in lost royalties and \$579 million in lost severance taxes. Present values for these losses are \$1.9 billion in lost revenue, \$384 million in lost royalties and \$96 million in lost severance taxes.¹⁶

¹⁶ Present value analysis assumed a 10 percent discount rate over 60 years.

Table 28: Evaluation of Impacts of Air Regulation Costs on Marginally Producing Wells

Item	Oil and Gas Leases					
	Base Case	WITH WPF & TANK less than 6	WITH WPF & TANK s>=6 to <=12	WITH WPF & TANK s>12 to <= 50	WITH WPF & TANK >50	WITH WPF & TANK TOTAL
LOE (\$/well/month)	\$900	\$900	\$900	\$900	\$900	\$900
Additional LOE with new rules (\$/well/month)	\$0	\$22	\$565	\$743	\$1,290	\$729
Total LOE (\$/wee/month)	\$900	\$922	\$1,465	\$1,643	\$2,190	\$1,629
Economic Limit (BOPD)	0.43	0.44	0.70	0.79	1.05	0.78
Remaining Oil (BO)	22,594	22,442	18,679	17,442	13,652	17,543
Estimated Oil Shut In (BO)	-	152	3,914	5,151	8,942	5,051
Facility Allocation	-	0.35	0.17	0.35	0.12	1
Production Lost (BO)	-	1,353,302	16,944,548	45,908,655	27,321,315	128,611,449
Lost Royalties (\$)	-	\$24,359,432	\$305,001,869	\$826,355,781	\$491,783,676	\$2,315,006,074
Lost Severance Taxes (\$)	-	\$6,089,858	\$76,250,467	\$206,588,945	\$122,945,919	\$578,751,519

*Values in the table have not been discounted and reflect revenues and costs over the life of the well.

Costs to Division to Implement Proposed Rules

The Economic Impact Analysis requires an assessment of the cost for the Division to implement the proposed rule changes. Oversight of an LDAR program, STEM plans, and annual report review of 5,312 tank batteries, 5,312 well production facilities, and 200 compressor stations with possibly hundreds of thousands of components would require additional Division manpower. Louis Berger reviewed the revised (November 21, 2013) Regulations 3, 6 and 7 to understand the implementation costs to the Division associated with the new rules. A summary of potential cost implications for the Division, as result of the rule changes, is provided in Table 29. The rationale for the estimated additional costs or cost savings is provided after the table.

Table 29: Summary of Potential Implementation Costs to the Division with Proposed Changes in Regulation 3, 6, and 7

Regulation Subpart	Description	Cost Impact	Estimated Savings/Cost
Regulation 3			
Minor Source Permits	Facilities with emissions less than the APEN no longer have to file for a minor source permit.	Cost Savings	An estimated 882 hours per year in labor would be saved from not having to review and approve minor source permits.
Standardization of de minimis Reporting Threshold	The de minimis reporting threshold would be set to a standard of 250 pounds per year. This increases the clarity of reporting requirements.	Cost Savings	An undetermined amount of savings would be realized by the Division.
Crude Oil Storage Tank Permitting	Additional permits would now be required for crude oil tanks as the tank permitting exemptions are removed.	Cost Increase	An estimated 128 hours per year in additional labor would be required to review and approve permits.
Regulation 6			
Adoption of NSPS OOOO	This regulation adopts NSPS OOOO. No additional impacts beyond the minimum required by federal law would occur.	No Impact	No Impact
Regulation 7			
Evaluation of Operation and Maintenance of Air Pollution Control Equipment	The Division would be required to make determinations on the acceptableness of operating and maintenance procedures used to control Air Pollution Control Equipment.	Cost Increase	An estimated 1,062 hours per year in additional labor would be required to review and monitor o&m procedures.
Approval of STEM Plans	The Division would be required to review and approve STEM plans for compliance with regulatory requirements.	Cost Increase	An estimated 5,600 hours in additional labor would be required for review and approval of STEM plans.

Ongoing Management of STEM Program	The Division would incur labor costs for review of records that would be retained by each operator or owner as part of their STEM plan compliance.	Cost Increase	An estimated 1,062 hours per year in additional labor would be required to manage the STEM program
Division Approval of Monitoring Devices or Methods	When the Division is required to approve monitoring devices or methods not mentioned in these regulations it is anticipated that additional labor costs to the Division would occur.	Cost Increase	An undetermined additional cost would be incurred by the Division.
Recordkeeping Requirements	The owner or operator of each facility is required to keep records of various tests and repairs. It is anticipated that the Division would review a percentage of these records annually.	Cost Increase	An estimated 1,062 hours per year in additional labor would be required.
Reporting Requirements	Each owner or operator is required to submit an annual report summarizing the inspection and maintenance activities of all facilities during the previous year. It is anticipated that the Division would review a percentage of these annual reports.	Cost Increase	An estimated 2,125 hours per year in additional labor would be required to review annual reports.
Venting Recordkeeping Requirements	Each owner or operator is required to record venting statistics and make them available to the Division upon request. Additionally, the Division may be called upon to make a determination on the visibility of venting. It is anticipated that the Division would commit a certain amount of time annually to reviewing these venting records and making visibility determinations on venting events.	Cost Increase	An estimated 2,125 hours per year in additional labor would be required for review and monitoring.

The following section provides an explanation of the implementation cost analysis summarized in Table 29 for each proposed rule change.

Regulation 3

Minor Source Permits

Under Regulation 3, the Division is proposing that NSPS OOOO affected facilities with uncontrolled actual emissions that are less than the APEN and minor source permit thresholds no longer automatically have to file APENs and obtain minor source permits. As such, it is expected that the Division would realize an implementation cost savings with this proposed rule change. As a result of this revision, up to 441 facilities would be exempt from submitting an APEN. If it is assumed that it requires two hours to process each APEN application, then this rule change could save the Division up to 882 hours of processing time. This would allow the Division to reallocate permitting resources to more complicated sources with greater impact to Colorado air quality, as well as develop and maintain other guidance and compliance assistance tools.

Standardization of de minimis Reporting Threshold

The Division is proposing to revise method (Part A, Appendix A) for determining non-criteria reportable pollutant de minimis levels in order to standardize the de minimis reporting threshold and set a 250 pounds per year threshold for all non-criteria reportable pollutants, regardless of the pollutant, height of release point or distance to property boundary. This revision increases regulatory clarity and reduces the administrative reporting burdens on both sources and the Division by simplifying the process. This revision is therefore anticipated to reduce costs to the Division though it is uncertain what the cost savings would be for this rule change.

Crude Oil Storage Tank Permitting

The Division is proposing to remove the crude oil storage tank permitting exemptions in Part B, Section II.D.1.n. and Part C, Section II.E.3.ddd. It is estimated that up to 64 additional crude oil tanks would be required to obtain a permit under this revision. If it is assumed that it takes approximately two hours to review and issue each permit, it is anticipated that this would result in up to 128 hours of additional labor for the Division each year to implement this rule.

Regulation 6

This regulation adopts NSPS OOOO; therefore, this rule makes NSPS OOOO enforceable under Colorado law and is not anticipated to impose additional requirements beyond the minimum required by federal law. The revised changes to this regulation are not anticipated to impact regulation implementation costs to the Division.

Regulation 7

It is anticipated that several new provisions of the revised Regulation 7 would require owners or operators of facilities to prepare reports and documentation or perform tasks that would require review, approval and inspection by the Division. These additional tasks are expected to result in an increase in the implementation costs to the Division.

Evaluation of Operation and Maintenance of Air Pollution Control Equipment

The revised regulations would require that air pollution control equipment be maintained and operated in a manner consistent with good air pollution practices. A determination on whether or not acceptable operating and maintenance procedures are being used at a facility would be based on information provided to the Division by the owner or operator of the facility. This information could include, but would not be limited to: monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. The requirement for the Division to make a determination on the acceptability of operating and maintenance procedures is expected to take 2 hours per facility per year. The Division has reported that there are 5,312 facilities that would be affected by this rule. If it is assumed that the Division would review approximately 10 percent of these records annually, then the rule change would require an additional 1,062 labor hours per year for implementation.

Approval of STEM Plans

Owners or operators of storage tanks would be required to develop, certify and implement a Storage Tank Emission Management System (STEM) plan to identify appropriate strategies to minimize emissions from venting at thief hatches (or other access points to a storage tank) and pressure relief devices during normal operation under the revised Regulation 7. It has been estimated that approximately 5,312 storage tanks under the revised regulations would have to meet the STEM requirements. Assuming that a STEM plan could be developed for sites with multiple tanks (2), at most, 2,800 STEM plans would be developed and require review by the Division. Assuming the Division would review and approve each plan and it would require 2 hours per review would result in an additional 5,600 hours to initially review and approve the individual STEM plans, resulting in additional implementation costs as a result of the revised regulation.

Ongoing Management of STEM Program

As each owner or operator of a storage tank subject to section XII.D or XVII.C under the revised regulation must maintain records of STEM, including the plan, any updates, and the certification; and as these records should be made available to the Division upon request, it is anticipated that the Division would incur additional implementation costs as a result of this requirement. Further document retention requirements under the revised regulation would include retention of the AIRS ID for the storage tank; the date and duration of any period where the thief hatch, pressure relief device, or other access point are found to be venting hydrocarbon emissions; the date and duration of any period where the air pollution control equipment is not operating, or where a flare or other combustion device is being used; the date and result of any Method 22 test, as well as the timing of and efforts made to eliminate venting, restore operation of air pollution control equipment, and mitigate visible emissions. While the Division is not required to review this information, the requirement for the retention of this information would allow it to be reviewed. It is anticipated that the Division would review approximately 10 percent of these records annually. As there would be at most 5,312 facilities under the revised regulations subject to these requirements and each would take an assumed 2 hours of review per set of records, this would require, at most, 1,062 hours per year, resulting in additional implementation costs as a result of the revised regulation.

Division Approval of Monitoring Devices or Methods

Under section XVII.F.6, the Division may be required to approve monitoring devices or methods not mentioned in these regulations, resulting in additional time and funding costs to the Division.

Recordkeeping Requirements

As a result of recordkeeping requirements under the proposed regulation, the owner or operator of each facility subject to inspection and maintenance requirements under Section XVII.F is required to maintain documentation of the pre-start-up pressure tests for new well production facilities; date and site information for each inspection; a list of leaking components and monitoring method used to determine the presence of the leak; the date of the first attempt to repair the leak and additional

attempts; the date the leak was repaired; the delayed repair list; the date the leak was re-monitored to verify effectiveness of the repair and the results of re-monitoring effort; and a list of identification numbers for the components designated as unsafe or inaccessible to monitor, as well as an explanation for each component stating why the component was so designated and the plan for monitoring such components for a period of two years and make them available to the Division upon request. It is anticipated that the Division would review approximately 10 percent of these records annually. As there would be at most 5,312 facilities under the revised regulations subject to these requirements and it is assumed to take approximately 2 hours of review per set of records, this would require, at most, 1,062 hours per year in additional labor. This would result in increased implementation costs of Regulation 7.

Reporting Requirements

In addition to recordkeeping, the owner or operator of each facility subject to the inspection and maintenance requirements in Section XVII.F would be required to submit a single annual report each year summarizing the inspection and maintenance activities at all of their subject facilities during the previous year. This report would contain at least the number of facilities inspected as well as the total number of inspections, leaks identified, categorized by component type and the number of leaks repaired. It would also require the identification of the number of leaks on the delayed repair list at the end of the calendar year. Additionally, each of these reports would be required to be accompanied by a self-certification form certifying the accuracy of the information in the report. It is anticipated that review of one annual report by the Division would require 4 hours. As there would be at most 5,312 annual reports, depending on the ownership of individual facilities in the state of Colorado, this new requirement is anticipated to add an additional amount of 2,125 hours, at most, of labor to the Division each year. This would result in increased implementation costs of Regulation 7.

Venting Recordkeeping Requirements

Records of the cause, date, time, and duration of venting events under Section XVII.H would be required to be kept and made available to the Division upon request under the revised regulation. Regarding visible emissions, the Commission expects that both Division inspectors and the regulated community will, if any smoke is observed, determine whether the emissions are considered visible emissions for purposes of Regulation Number 7. When the venting event records are reviewed by the Division or if the Division makes a determination on the visibility of emissions this would result in additional implementation costs as a result of the revised regulation. It is anticipated that the average time required to determine the visibility of emissions or review the records of a facility would be four hours per facility. As there would be, at most, 5,312 facilities that may require review by an inspector annually and assuming 10 percent of these facilities require monitoring per year it is anticipated that up to 2,125 labor hours would be required. This would result in increased implementation costs of Regulation 7.

Conclusions

The net increase in the number of labor hours at the Division as result of the proposed regulations is anticipated to be approximately 12,282 labor hours annually. Notably, the Division would need 5,600 hours to review and approve initial STEM plans required under Regulation 7, the largest estimated time commitment for the Division. This represents approximately 6.1 FTEs of additional staff for the Division to review, oversee, inspect, manage, and approve various requirements associated with the proposed rules. Therefore, Louis Berger concludes that the Division would incur significant additional net costs to implement the proposed requirements beyond current expenditures, contrary to the Division's assertions to date.

Support of Industry's Proposed Language

The results of the initial economic impact analysis presented here support the industry's key suggested revisions to the Division's proposed rule. Specifically, the proposed revisions will allow similar emission reductions to be achieved in a much more cost effective manner than the regulatory approach proposed by the Division. Key points to the analysis include:

- Diminishing marginal benefits associated with LDAR programs implies increasing costs per ton of VOC reduced after initial rounds of inspections and repairs. Reducing the monitoring to reflect successful LDAR implementation reduces costs and improves the cost effectiveness of the proposed rule compared to the Division's proposal while maintaining program integrity through realized emission reductions. The "step-down" of monitoring frequency, which rewards companies with four inspections with no leaks, is an example of how the industry changes to the proposed rule would provide incentives for industry to maintain compliance and reduce costs for good performance.
 - Generally, compliance costs of STEM and LDAR for small tanks and well production facilities are more burdensome than for larger facilities on a cost per ton basis. As such, requiring a one-time LDAR inspection and monthly AVO for all facilities (including all well production facilities) with uncontrolled emissions between 2 and 6 TPY would improve the overall cost effectiveness of the proposed rule by limiting the very high costs per ton of VOC reduced incurred by very small facilities with very small VOC fugitive emissions.
 - Compliance costs are higher for operations outside of the non-attainment area as the distance among facilities and tanks increases inspection travel time and expenses. Limiting the geographic scope to the non-attainment area will improve the cost effectiveness of the proposed rule.
 - Allowing for the use of other established technology, such as the tunable diode laser absorption technology (TDLAS), as an option for inspection monitoring, would reduce costs to industry with faster inspections, reduced camera training requirements, among other factors.
-

**Expert Rebuttal Report and Rebuttal Written Testimony of Gernot Wagner, Ph.D.
Characterizing the Economic Benefits of Anticipated Methane Reductions for the Proposed
Amendment to Colorado's Proposed Oil and Gas Regulation with Respect to Climate
Change**

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Expert Introduction: Dr. Gernot Wagner

My name is Gernot Wagner, Ph.D., and I am a senior economist at EDF, where I co-lead the office of economic policy and analysis to advocate for market-based solutions to a wide range of environmental problems. I teach energy economics as adjunct faculty at Columbia's School of International and Public Affairs, and I am the author of *But Will the Planet Notice?* (Hill & Wang/Farrar, Strauss & Giroux, 2011) and, joint author with Harvard University's Martin Weitzman, of the forthcoming *Climate Shock* (Princeton University Press). I am a research associate at the Harvard Kennedy School and a term member of the Council on Foreign Relations. Prior to EDF, I worked for the Boston Consulting Group and served on the editorial board of the *Financial Times*. I hold a Ph.D. and M.A. in Political Economy and Government as well as an A.B. in Environmental Science and Public Policy, and Economics (*magna cum laude* with highest honors in the field) from Harvard University, and an M.A. in Economics from Stanford University. A copy of my cv is attached as Exhibit A to this expert report and testimony.

The following is my written testimony on the topics covered in this report, based on my education, research, and expertise on the topic of the Social Cost of Carbon and related issues.

Summary of Written Testimony and Expert Opinion

Calculating the social costs of greenhouse gas pollutants has a long tradition in the academic literature. In 2010, the United States' Interagency Working Group ("IWG") calculated the Social Cost of Carbon ("SCC") in a transparent, well-reviewed inter-agency process involving a dozen federal agencies and entities. A routine update in 2013, reflecting the latest changes in the peer-reviewed literature resulted in a central estimate for the SCC of \$37 per ton of carbon dioxide emitted in 2015. Converting the value into one reflecting the social cost of methane – and making conservative assumptions every step along the way – results in a central value of the social benefit of methane reductions for the proposed oil and gas rule in Colorado per year: over \$104,000,000 when fully implemented in 2016 and increasing to \$132,000,000 in 2025. The upper range of the central estimate reaches over \$318,000,000 per year in 2016 and over \$404,000,000 per year in 2025.

Social Cost of Carbon

The SCC is a monetary measure of the incremental damage to the climate resulting from carbon dioxide emissions. The SCC assigns a net present value to the marginal impact of one additional ton of carbon dioxide emissions released at a specific point in time. The SCC is based on a large and growing body of research regarding the quantitative economic damages that would result from unmitigated climate change. These economic estimates are typically based on the results of integrated assessment models, in which a scientific model of the predicted physical impacts of climate change is paired with a socio-economic model that evaluates the economic impact of these effects.

The most comprehensive effort to calculate the SCC is the work published by the IWG. The IWG is a group of numerous federal agencies/departments, including the Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Management and Budget, Office of Science and Technology Policy, and the Department of the Treasury. The IWG developed the SCC through an open and transparent process, involving extensive meetings, public comment and peer review. The SCC developed by the IWG is widely used in regulatory rulemakings in the United States.¹

¹ The SCC has been used in numerous notice-and-comment rulemakings by various agencies since it was published in 2010, and each of these occasions has provided opportunity for public comment on the SCC. *See, e.g.*, Energy Conservation Program: Energy Conservation Standards for Residential Clothes Washers, 77 Fed. Reg. 32,381 (May 31, 2012); Energy Conservation Program: Energy Conservation Standards for Residential Dishwashers, 77 Fed. Reg. 31,964 (May 30, 2012); Energy Conservation Program: Energy Conservation for Battery Chargers and External Power Supplies, 77 Fed. Reg. 18,478 (Mar. 27, 2012); Energy Conservation Program: Energy Conservation Standards for Standby Mode and Off Mode for Microwave Ovens, 77 Fed. Reg. 8526 (Feb. 14, 2012); Energy Conservation Program: Energy Conservation Standards for Distribution Transformers, 77 Fed. Reg. 7282 (Feb. 10, 2012); Energy Conservation Program for Certain Industrial Equipment: Energy Conservation Standards and Test Procedures for Commercial-Heating, Air-Conditioning, and Water-Heating Equipment, 77 Fed. Reg. 2356 (Jan. 17, 2012); 2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards, 76 Fed. Reg. 74,854 (Dec. 1, 2011); Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 76 Fed. Reg. 52,738 (Aug. 23, 2011); Energy Conservation Program: Energy Conservation Standards for Residential Furnaces and Residential Central Air Conditioners and Heat Pumps, 76 Fed. Reg. 37,549 (June 27, 2011); Energy Conservation Program: Energy Conservation Standards for Residential Clothes Dryers and Room Air Conditioners, 76 Fed. Reg. 22,324 (Apr. 21, 2011); Energy Conservation Program: Energy Conservation Standards for Fluorescent Lamp Ballasts, 76 Fed. Reg. 20,090 (Apr. 11, 2011); National Emission Standards for Hazardous Air Pollutants: Mercury Emissions from Mercury Cell Chlor-Alkali Plants, 76 Fed. Reg. 13,852 (Mar. 14, 2011); Greenhouse Gas Emissions Standards

The IWG's most recent value for the social cost of carbon is \$37/ton (central value for a ton released in 2015, assuming a 3% discount rate).² The SCC is derived from running three state-of-the-art, peer-reviewed Integrated Assessment Models ("IAMs") that quantify the costs of climate change to the economy. They project future economic output with and without climate change using five reference scenarios and three constant discount rates of 2.5, 3, and 5 percent. The use of three models, three discount rates, and five scenarios produces a number of distributions for the SCC. The final \$37 number is the average of the monetized effect found by all three models under the central model run, assuming a 3% discount rate. SCC values rise over time, reflecting the increased costs of unmitigated climate change over time. A ton emitted in 2020 is calculated to come with a social cost of \$43; a ton emitted in 2025 will cost \$47 (Table 1).

This central value is conservative because it does not reflect a declining discount rate, fully value impacts associated with catastrophic events, or include non-monetized benefits. The latter may be the most significant omission, since quantifying the full cost of climate damages is difficult. The IWG also presents a value for the 95th-percentile of the SCC distribution as a conservative proxy for including the value of extreme events (Table 1). This estimate can only be seen as a proxy and is likely a large underestimate of the actual damages in extreme situations.³

and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles, 75 Fed. Reg. 74,152 (Nov. 30, 2010); Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units, 75 Fed. Reg. 63,260 (Oct. 14, 2010); Energy Conservation Program: Energy Conservation Standards for Residential Refrigerators, Refrigerator-Freezers, and Freezers, 75 Fed. Reg. 59,470 (Sept. 27, 2010); Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, 75 Fed. Reg. 45,210 (Aug. 2, 2010).

² EDF-REB-GW-EX B. "[Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866](#)" (November 1, 2013)

³ E.g.: Pindyck, Robert S. 2012. "Uncertain outcomes and climate change policy." *Journal of Environmental Economics and Management* 63, no. 3: 289-303. (EDF-REB-GW-EX C) Weitzman, Martin. "GHG Targets as Insurance Against Catastrophic Climate Damages." *Journal of Public Economic Theory*. 2012;14(2):221-244. (EDF-REB-GW-EX D) Pindyck, Robert S. 2013. "The Climate Policy Dilemma." *Review of Environmental Economics and Policy* vol. 7(2):219-237. (EDF-REB-GW-EX E) Wagner, Gernot and Richard J. Zeckhauser. "Expecting a Black Swan and Getting a Dragon: Confronting Deep Uncertainty in Climate Change." ASSA Conference presentation (January 3, 2014). (EDF-REB-GW-EX F)

Table 1—Social cost of carbon dioxide, 2010-2050 (in 2007 dollars per metric ton of CO₂)

	5.0%	3.0%	2.5%	3.0%
Year	Avg	Avg	Avg	95th
2010	11	32	51	89
2015	11	37	57	109
2020	12	43	64	128
2025	14	47	69	143
2030	16	52	75	159
2035	19	56	80	175
2040	21	61	86	191
2045	24	66	92	206
2050	26	71	97	220

Using the Social Cost of Carbon to Calculate Damage associated with Methane Emissions

Each greenhouse gas has its own potential to force changes to the climate, and those impacts can also differ over time. To evaluate the SCC of a non CO₂ greenhouse gas, such as methane, it is necessary to convert those emissions to the same units as the SCC, using the Global Warming Potential (“GWP”) of the gas at issue. GWP is a measure of the climate forcing potential of a gas (such as methane) relative to CO₂.

The most recent Intergovernmental Panel on Climate Change (“IPCC”) establishes the 100-year GWP for methane at a figure of at least 28, which means that methane is 28 times more potent

than CO₂ over a 100-year period.⁴ However, because methane causes greater climate damage over shorter time frames than over longer time frames, choosing a 100-year GWP will undervalue the short-term impacts of methane. Accordingly, the benefits of methane reductions should also be valued using the most-recent 20-year GWP for methane, which is at least 84.

These GWP values for methane (28 long term and 84 short term) are conservative because they do not include climate-carbon (“cc”) feedbacks (which are feedbacks between climate change and the carbon cycle). The latest IPCC report concludes that, when cc is considered, methane has an even higher GWP on both 100- and 20-year timeframes of 34 and 86, respectively.⁵ Other scientific analyses have likewise determined that methane is an even more potent climate forcer.⁶

Table 2 below shows the GWP of methane in the short and long term from the most recent IPCC report, both with and without climate-carbon feedback.

Table 2—Global Warming Potential (GWP) of methane relative to one metric ton of CO₂

	Global Warming Potential (GWP) relative to CO ₂
100-year GWP without cc feedbacks	28
100-year GWP with cc feedbacks	34
20-year GWP without cc feedbacks	84
20-year GWP with cc feedbacks	86

⁴CLIMATE CHANGE 2013: THE PHYSICAL SCIENCE BASIS, CONTRIBUTION OF WORKING GROUP I TO THE FIFTH ASSESSMENT REPORT OF THE INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE at Table 8.A.1 (Joussaume, S., J. Penner & F. Tangang eds. 2013), available at http://www.climatechange2013.org/images/uploads/WGIAR5_WGI-12Doc2b_FinalDraft_All.pdf.

⁵ *Id.* at Table 8.7.

⁶ EDF-REB-GW-EX G. D.T. Shindell, G. Faluvegi, D.M. Koch, G.A. Schmidt, N. Unger, S.E. Bauer (2009) “Improved Attribution of Climate Forcing to Emissions,” *Science* **326** 716-718.

This conversion yields a conservative estimate—undervaluing the benefits of methane reductions by up to 36%.⁷

Calculating the Benefits of Anticipated Methane Reductions from Proposed Changes to Air Pollution Control Regulations in Colorado

An expert retained by EDF, WZI Inc., estimates that the proposed rule will reduce methane emissions by around 112,000 short tons per year once fully implemented (EDF-PHS-WZI Expert Report, Table 7-1). Table 3, below, calculates the value of avoided methane emissions in 2007 dollars for 2015, 2020, and 2025 by using central values for the social cost of carbon (at the central 3% discount rate). This table results from the IWG values for SCC, the IPCC values for GWP of methane, and the WZI estimate of methane reductions. Benefits are calculated using both 100- and 20-year GWPs for methane, and GWPs with and without climate-carbon feedbacks. The calculations are performed by multiplying the SCC (shown in the top row) by the GWP of methane (shown in the column on the left) times the tons of methane reduced (112,000 short tons based on current oil and gas production activity in Colorado, equal to 102,000 metric tons).

In 2015, the central value for calculated benefits is \$104,000,000, going as high as \$318,000,000. In 2025, the central value for calculated benefits is \$132,000,000, going as high as \$404,000,000 (Table 3).

The values below almost certainly understate the actual SCC associated with these emissions.

Among other things:

- The values are stated in 2007 dollars, so the values are understated in terms of current dollars.

⁷ EDF-REB-GW-EX H. Marten, Alex L., and Stephen C. Newbold. "Estimating the social cost of non-CO2 GHG emissions: Methane and nitrous oxide." *Energy policy* 51 (2012): 957-972, at 964; Marten, A. L., and Newbold, S. C. (2011), "Estimating the Social Cost of Non-CO2 GHG Emissions: Methane and Nitrous Oxide," EPA NCEE Working Paper # 11-01, at 16, available at <http://www.sciencedirect.com/science/article/pii/S0301421512008555>.

- The 2025 reductions only account for the existing rates of production. Production is projected to increase, so the actual reductions compared to the business as usual case would be greater than indicated below.
- This estimate does not include the monetary impact of extreme climate events. IWG prepared an SCC that includes these factors (shown as the “95th percentile” value in Table 1 above). The estimate for these factors would increase the values below by approximately a factor of three.
- The conversion of the SCC to the social cost of methane using GWP is likely conservative, resulting in a further underestimate.⁸

Table 3—Benefits of Methane reductions from Proposed Oil and Gas Rule (in 2007 dollars)

	2015	2020	2025
	3.0% Average (SCC: \$37)	3.0% Average (SCC: \$43)	3.0% Average (SCC: \$47)
100-year GWP without cc feedbacks (GWP: 28)	\$104 million	\$120 million	\$132 million
100-year GWP with cc feedbacks (GWP: 34)	\$126 million	\$146 million	\$160 million
20-year GWP without cc feedbacks (GWP: 84)	\$311 million	\$361 million	\$395 million
20-year GWP with cc feedbacks (GWP: 86)	\$318 million	\$370 million	\$404 million

⁸ See footnote 7 above.

I, Gernot Wagner, of proper age, state that the above-testimony has been prepared by me, or under my supervision and control, and that it is true and correct to the best of my knowledge, and belief, and would be the same if given orally under oath.


Dr. Gernot Wagner
Date: January 30, 2014

**EXHIBIT A
TO THE JOINT INDUSTRY WORK GROUP REBUTTAL STATEMENT**

REVISED COLLECTIVE PROPOSED REVISIONS

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 3

STATIONARY SOURCE PERMITTING AND AIR POLLUTANT EMISSION NOTICE REQUIREMENTS

5 CCR 1001-5

>>>>>>>>

PART A CONCERNING GENERAL PROVISIONS APPLICABLE TO REPORTING AND PERMITTING

>>>>>>>>

II. Air Pollutant Emission Notice (APEN) Requirements

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II.B.3. APEN Applicability

For the purposes of Air Pollutant Emission Notice applicability, a source will be considered to be an individual emission point, or group of points pursuant to Section II.B.4. of this Part A.

II.B.3.a. Criteria Pollutants

For criteria pollutants, Air Pollution Emission Notices are required for: ~~each individual emission point in a nonattainment area with uncontrolled actual emissions of one ton per year or more of any criteria pollutant (pollutants are not summed) for which the area is nonattainment;~~ each individual emission point ~~in an attainment or attainment/maintenance area~~ with uncontrolled actual emissions of two tons per year or more of any individual criteria pollutant (pollutants are not summed); and each individual emission point with uncontrolled actual emissions of lead greater than one hundred pounds per year, regardless of where of where the source is located.

II.B.3.b. Non-criteria Reportable Pollutants

For non-criteria reportable pollutants, Air Pollutant Emission Notices are required for each individual emission point with uncontrolled actual emissions ~~equal to or greater than 250 pounds per year or more of any individual non-criteria reportable pollutant (pollutants are not summed) that exceed the de minimis levels as determined following the procedures set forth in Appendix A.~~

>>>>>>>>

II.D. Exemptions from Air Pollutant Emission Notice Requirements

- II.D.1. ~~Notwithstanding the exemptions contained in Section II.D.1., Air Pollutant Emission Notices must be filed for all emission units specifically identified in the applicability section of any subpart of Part A of Regulation Number 6 (New Source Performance Standards) and/or Regulation Number 8 (Hazardous Air Pollutants), Parts A, C, D, and E. However, Air Pollutant Emission Notices need not be filed for wet screening operations subject to Subpart 000 of the New Source Performance Standards if the exemption in Section II.D.1.cccc. is applicable.~~

Stationary sources having emission units that are exempt from the requirement to file an Air Pollutant Emission Notice must nevertheless comply with all requirements that are otherwise applicable specifically to the exempted emission units, including, but not limited to: Title V, Prevention of Significant Deterioration, nonattainment New Source Review, opacity limitations, odor limitations, particulate matter limitations, and volatile organic compounds controls.

An applicant may not omit any information regarding APEN exempt emission units in any permit application if such information is needed to determine the applicability of Title V (Part C of this Regulation Number 3), Prevention of Significant Deterioration (Section VI., Part D of this Regulation Number 3), or nonattainment New Source Review (Section V., Part D of this Regulation Number 3).

The following sources are exempt from the requirement to file Air Pollutant Emission Notices because by themselves, or cumulatively as a category, they are deemed to have a negligible impact on air quality.

- II.D.1.a. Individual emission points ~~in nonattainment areas having uncontrolled actual emissions of any criteria pollutant of less than one ton per year, and individual emission points in attainment or attainment/maintenance areas having uncontrolled actual emissions of any criteria pollutant of less than two tons per year, and each individual emission point with uncontrolled actual emissions of lead less than one hundred pounds per year, regardless of where the sources is located.~~
- II.D.1.b. Individual emission points ~~of non-criteria reportable pollutants~~ having uncontrolled actual emissions ~~of any individual non-criteria reportable pollutant less than the de minimis levels as determined following the procedures set forth in Appendix A~~ 250 pounds per year.

>>>>>>>>

APPENDIX A
APPENDIX A

~~Method For Determining~~ De Minimis Levels For Non-Criteria Reportable Pollutants

An Air Pollutant Emission Notice must be filed for each emission point (individual or grouped) that has uncontrolled actual emissions equal to or greater than 250 pounds per year of any non-criteria reportable pollutant listed in Appendix B.

If a non-criteria pollutant is not listed in Appendix B, it does not have to be reported unless it is included in a chemical compound group.

~~The following procedures must be followed in order to determine the appropriate de minimis (minimum) reporting level for each pollutant that is emitted from each emission point at a contiguous site. If you do not wish to use the three scenario approach at your facility, you may elect to use Scenario 1 for all emission points.~~

Definitions

~~Release Point – the lowest height above ground level from which the pollutants are emitted to the atmosphere.~~

~~Property Boundary – the distance from the base of the release point to the nearest property boundary.~~

Point - an individual emission point or a group of individual emission points reported on one Air Pollutant Emission Notice as provided for in Part A, Section II.B.4.

Methodology

~~To determine the de minimis level for a single pollutant being emitted from a point (single or grouped).~~

STEP 1:

~~Determine which of the three scenarios below applies to the emission point. If different scenarios can be applied to the same emission point, use the highest numbered scenario that applies. In the case of grouped emission points, use the lowest scenario number (for the entire group) that applies to any of the single emission points within the group.~~

~~Scenario 1: — Release point less than 10 meters or property boundary less than 100 meters;~~

~~Scenario 2: — Release point equal to or greater than 10 meters, but less than 50 meters, or property boundary equal to or greater than 100 meters, but less than 500 meters; or~~

~~Scenario 3: — Release point equal to or greater than 50 meters, or property boundary equal to or greater than 500 meters.~~

STEP 2:

~~Use Appendix B to identify which of the three bins (Bin A, B, or C) the chemical is listed under.~~

~~If the pollutant is not listed, it does not have to be reported unless it is included in a chemical compound group.~~

STEP 3:

~~Use the table below to determine the de minimis level.~~

~~All values are in pounds per year.~~

	Scenario 1	Scenario 2	Scenario 3
Chemical Bin	De-Minimis	De-Minimis	De-Minimis
Bin A	50	125	250

Bin B	500	1250	2500
Bin C	1000	2500	5000

STEP 4:

~~Repeat the above steps for each pollutant emitted from each emission point (single or grouped). One Air Pollutant Emission Notice must be filed for each emission point that emits one or more chemicals above the de minimis level.~~

>>>>>>>

PART B CONCERNING CONSTRUCTION PERMITS

>>>>>>>

II. General Requirements For Construction Permits

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II.A.5. Construction permits are required for hazardous air pollutants if:

II.A.5.a. The source is subject to Colorado Maximum Achievable Control Technology or Generally Available Control Technology; ~~or~~

~~II.A.5.b. The source is subject to Federal National Emission Standards for Hazardous Air Pollutants; or~~

~~II.A.5.c. The source is subject to Federal Maximum Achievable Control Technology or Generally Available Control Technology standards; or~~

~~II.A.5.d. The source is subject to Regulation Number 8, Part E, where the more specific requirements of Regulation Number 8, Part E, take precedence over requirements in this regulation.~~

>>>>>>>

II.D. Exemption from Construction Permit Requirements

~~None of the exemptions listed below in Sections II.D.1. through II.D.4. shall apply if a source is subject to Part A of Regulation Number 6 (New Source Performance Standards) and/or Regulation Number 8 (Hazardous Air Pollutants), Parts A, C, D, and E. Permit exemptions taken under this section do not affect the applicability of the any State or Federal regulations that are otherwise applicable to the source.~~

An applicant may not omit any information regarding APEN or permit exempt emission units in any application if such information is needed to determine the applicability of Title V (Part C of this Regulation Number 3), Prevention of Significant Deterioration (Section VI. of Part D of this Regulation Number 3), or Nonattainment New Source Review (Section V. of Part D of this Regulation Number 3).

II.D.1. The following sources are exempt because by themselves, or cumulatively as a category, ~~they~~ are deemed to have a negligible impact on air quality:

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II.D.1.l. Crude oil truck loading equipment at exploration and production sites where the loading rate does not exceed 10,000 gallons of crude oil per day averaged on an annual basis. Condensate truck loading equipment at exploration and production sites that splash fill less than 6750 barrels of condensate per year or that submerge fill less than 16308 barrels of condensate per year. ~~Crude oil or condensate loading truck equipment at crude oil production sites where the loading rate does not exceed 10,000 gallons per day averaged over any thirty-day period.~~

>>>>>>>

II.D.1.n. ~~Exemption Repealed Crude oil storage tanks with a capacity of 40,000 gallons or less.~~

II.D.2. ~~Facilities located in a nonattainment area for any criteria pollutant for which the area is nonattainment; with t~~Total facility-wide uncontrolled actual emissions ~~(potential emissions at actual operating hours)~~ that are less than the following amounts:

II.D.2.a. ~~Two Twenty five~~ tons per year ~~of~~ volatile organic compounds.

II.D.2.b. ~~One ton per year PM10Twenty five tons per year of any other criteria pollutant, except for lead.~~

II.D.2.c. ~~One ton per year PM2.5.~~

II.D.2.d. ~~Five tons per year total suspended particulate.~~

II.D.2.e. ~~Five tons per year carbon monoxide.~~

II.D.2.f. ~~Five tons per year sulfur dioxide.~~

II.D.2.g. ~~Facilities located in attainment or attainment/maintenance areas for all criteria pollutants with total facility uncontrolled actual emissions less (potential emissions at actual operating hours) than the following amounts:~~

II.D.3. ~~Facilities located in attainment or attainment/maintenance areas for all criteria pollutants with total facility uncontrolled actual emissions less (potential emissions at actual operating hours) than the following amounts:~~

II.D.3.a. ~~Five tons per year volatile organic compounds.~~

II.D.3.b. ~~Five tons per year PM10.~~

II.D.3.c. ~~Five tons per year PM2.5.~~

II.D.3.d. ~~Ten tons per year total suspended particulate.~~

II.D.3.e. ~~Ten tons per year carbon monoxide.~~

II.D.3.f. ~~Ten tons per year sulfur dioxide.~~

II.D.3.g. ~~Ten tons per year nitrogen oxides.~~

II.D.3.h. ~~Two hundred pounds per year lead.~~

II.D.~~34~~. Facilities that emit any other criteria pollutant that is not listed in Sections II.D.2. ~~and II.D.3~~, above (fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, reduced sulfur compounds, and municipal waste combustor engines), with total facility uncontrolled actual emissions of such pollutants that are less than ~~two~~ twenty five tons per year.

II.D.~~55~~. When a facility that was previously exempt from permit requirements exceeds one of the permit de minimis levels stated in Sections II.D.2. ~~through II.D.4~~, above, due to the addition of new emission points or an increase in uncontrolled actual emissions, the Division will issue either a facility-wide permit for all non-grandfathered emission units above that require Air Pollutant Emission Notices ~~s de minimis levels~~, or individual emission permits for those emission units that are not otherwise permit exempt.

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PART C CONCERNING OPERATING PERMITS

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II.E. Insignificant Activities and Exemptions from Operating Permit Requirements

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The following sources are exempt from the requirement to obtain an operating permit pursuant to this Part C:

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II.E.3.ddd. ~~Exemption Repealed *Crude oil storage tanks with a capacity of 40,000 gallons or less.~~

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PART D CONCERNING MAJOR STATIONARY SOURCE NEW SOURCE REVIEW AND PREVENTION OF SIGNIFICANT DETERIORATION

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XV. Actuals PALs

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XV.F. Contents of the PAL permit.

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XV.F.5. A requirement that, once the PAL expires, the major stationary source is subject to the requirements of Section XV.~~H~~.

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT
Air Quality Control Commission
REGULATION NUMBER 6
STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES
5 CCR 1001-8

PART A

Federal Register Regulations Adopted by Reference

>>>>>>>

The Air Quality Control Commission adopts in full Subpart OOOO, ~~Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, 40 CFR Part 60, Subpart OOOO (July 1, 2012), as amended by 78 Fed. Reg. 58416 (September 23, 2013) only if the Environmental Protection Agency (EPA), approves the Air Quality Control Commission's Revisions to Regulation Number 3 adopted on [insert date]. If the EPA disapproves of the Air Quality Control Commission's Revisions to Regulation Number 3 adopted on [insert date], full adoption of Subpart OOOO, Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, 40 CFR Part 60, Subpart OOOO (July 1, 2012), as amended by 78 Fed. Reg. 58416 (September 23, 2013) by the Air Quality Control Commission herein will be immediately and automatically withdrawn.~~ August 16, 2012, (77 FR 49490) where both uncontrolled actual emissions from the affected facility are equal to or greater than the Air Pollution Emission Notice (APEN) thresholds found at Regulation Number 3, Part A, Sections II.B.3.a. or II.B.3.b. and total facility uncontrolled actual emissions are equal to or greater than the permitting thresholds found at Regulation Number 3, Part B, Sections II.D.2., II.D.3., or II.D.4. for the following affected facilities: storage vessels at well sites beginning ninety days after the first day of production; storage vessels at any site other than well sites in the oil and natural gas production segment, the natural gas processing segment, and the natural gas transmission and storage segment; centrifugal compressors with wet seals; reciprocating compressors; pneumatic controllers; the group of all equipment (equipment leaks or leaking components) at on-shore natural gas processing plants; and sweetening units at on-shore natural gas processing plants.

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 7

CONTROL OF OZONE VIA OZONE PRECURSORS ~~AND CONTROL OF HYDROCARBONS VIA OIL AND GAS EMISSIONS~~

(EMISSIONS OF VOLATILE ORGANIC COMPOUNDS AND NITROGEN OXIDES)

5 CCR 1001-9

[The Joint Industry Work Group proposes that all Division Proposed Rules as well as any changes made in this Revised Collective Proposed Revisions document apply only in the ozone nonattainment area]

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II. General Provisions

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II.B. Exemptions

Emissions of the organic compounds listed as having negligible photochemical reactivity in the common provisions definition of Negligibly Reactive Volatile Organic Compound are exempt from the provisions of this regulation.

~~(State Only) Notwithstanding the foregoing exemption, hydrocarbon emissions from oil and gas operations, including methane and ethane, are subject to this regulation as set forth in Sections XVII. and XVIII.~~

>>>>>>>

XVII. (State Only, except Section XVII.E.3.a. which was submitted as part of the Regional Haze SIP) Statewide Controls for Oil and Gas Operations and Natural Gas-Fired Reciprocating Internal Combustion Engines

XVII.A. (State Only) Definitions

XVII.A.1 "Air Pollution Control Equipment," as used in this Section XVII, means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment and pollution prevention devices and processes intended to reduce uncontrolled actual emissions that comply with the requirements of Section XVII.B.2.e.

~~XVII.A.2. "Approved Instrument Based Monitoring Method" or "AIMM," as used in this Section XVII, means an infra-red camera with cooled InSb focal plane array with non-dispersive infra-red filter, tunable diode laser absorption spectroscopy ("TDLAS"), flame ionization detector, optical methane detector, infra-red controlled interference polarization spectrometer, cavity ring-down spectroscopy, mid-infra-red laser-based differential absorption light detection and ranging ("LIDAR"), pulsed infra-red laser, three-channel~~

non-dispersive gas correlation infra-red spectrometer, EPA Method 21, or other Division approved instrument based monitoring, device or method. If an owner or operator elects to use a Division approved Continuous Emission Monitoring program continuous emission monitoring, the Division may approve a streamlined inspection and reporting program for such operations. Any instrument based monitoring method approved by the Division under this definition must be at least as effective as Method 21 or an infra-red camera.

XVII.A.2. "Atmospheric", when used to modify the term "condensate storage tank", means a type of condensate storage tank that vents, or is designed to vent, to the atmosphere.
"Auto-Igniter" means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust volatile organic compound VOC emissions.

XVII.A.4. "Centrifugal Compressor" means any machine used for raising the pressure of natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart.

XVII.A.5. "Component" means each pump seal, compressor seal, flange, pressure relief device, connector, open ended line, and valve that contains or contacts a process stream with hydrocarbons at least 10 percent VOCs by weight. For the purpose of Section IXVII., Pprocess streams does not include those streams consisting of glycol, amine, produced water, or methanol are not components for purposes of this Section XVII.

XVII.A.56. "Connector" means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Jointed fittings welded completely around the circumference of the interface are not considered connectors.

XVII.A.36. "Condensate Storage Tank" means any production tank or series Date of First Production" means the date reported to the COGCC as the "first date of first production tanks that are manifolded together that store condensate."

XVII.A.78. "Glycol Natural Gas Dehydrator" means any device in which a liquid glycol (including ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.

XVII.A.9 "Intermediate Hydrocarbon Liquid" means any naturally occurring, unrefined petroleum liquid, as defined in 40 CFR Part 60, Subpart OOOO.

XVII.A.89. "Multi-Well Site" means a common well pad from which multiple wells may be drilled to various bottomhole locations.

XVII.A.910. "Natural Gas Compressor Station" means a facility, located downstream of well production facilities, which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure and recompress prior to the inlet of a natural gas prior to processing plant.

XVII.A.1011. "Normal Operation" means all periods of operation, excluding malfunctions as defined in Section I.G. of the Common Provisions regulation. For storage tanks at well production facilities, normal operation includes, but is not limited to, liquid dumps from the separator.

~~XVII.A.11~~XVII.A.12. "Open-Ended Valve or Line" means any valve, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

XVII.A.13. "Reciprocating Compressor" means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of the driveshaft.

XVII.A.14. "Stabilized" when used to refer to crude oil, condensate, intermediate hydrocarbon liquids, or produced water means that the vapor pressure of the liquid is sufficiently low to prevent the production of vapor phase upon transferring the liquid to an atmospheric pressure in a storage tank, and that any emissions that occur are limited to those commonly referred to within the industry as working, breathing, and standing losses.

XVII.A.~~12~~15. "Storage Tank" means any permanent fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. Storage vessel is as defined in 40 CFR Part 60, Subpart OOOO. Storage tanks may be located at a well production facility or other location.

XVII.A.~~13~~16. "Unsafe to Monitor" means a component is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential immediate danger as a consequence of such monitoring.

XVII.A.16. "Uncontrolled Release" means emissions from thief hatches (or other access points to the storage tank) and pressure relief devices at a storage tank that result from inadequate design, operation, or maintenance, except for those emissions that are necessary for the safety of personnel and equipment. Emissions during routine maintenance, tank gauging, and loadout operations shall not be considered Uncontrolled Releases.

XVII.A.~~14~~17. "Visible Emissions" means observations of smoke for any period or periods of duration greater than or equal to one (1) minute in any fifteen (15) minute period during normal operation pursuant to EPA Method 22. Visible emissions do not include radiant energy or water vapor. This definition also applies to Visible Emissions as referred to in XII of this Regulation Number 7.

XVII.A.~~15~~18. "Well Production Facility" means all permanent equipment co-located at a single stationary source directly associated with one or more oil wells or gas production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline located at the inlet to the separator through the point of Custody Transfer. Oil and gas production wells located on the same surface disturbance as the single stationary source are included in the Well Production Facility. "Custody Transfer" means the transfer of produced crude oil and/or condensate, after processing and/or treating in the producing operations, from Storage Tanks or automatic transfer facilities to sales pipelines or any other forms of post-sales transportation or the point at which natural gas passes from Well Production Facilities to natural gas gathering lines through which gathered natural gas is conveyed to Compressor Stations.

XVII.B. (State Only) General Provisions

These Regulations shall not apply to any lands within the exterior boundaries of the Southern Ute Indian Reservation, as agreed in, and defined by, that Intergovernmental Agreement between the Southern Ute Indian Tribe and the State of Colorado Concerning Air Quality Control on the Southern Ute Indian

Reservation, codified at Colorado Revised Statutes Section 24-62-101 (2013); (see also C.R.S. § 25-7-1301 (2013)); and approved by the United States Environmental Protection Agency on March 2, 2012 at 77 Fed. Reg. 15267 (March 14, 2012).

XVII.B.1. General requirements for prevention of emissions and good air pollution control ~~equipment, prevention of leakage, and flares and combustion devices practices for all oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.~~

XVII.B.1.a. All intermediate hydrocarbon liquids collection, storage, processing, and handling operations, regardless of size, shall be designed, operated, and maintained so as to minimize leakage of volatile organic compounds VOCs and other hydrocarbons to the atmosphere to the extent reasonably practicable.

XVII.B.1.b. At all times, including periods of start-up and shutdown, the facility and air pollution control equipment shall must be maintained and operated in a manner consistent with good air pollution control practices for minimizing VOC emissions. Determination of whether or not acceptable operating operation and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operating operation and maintenance procedures, and inspection of the source.

XVII.B.2. General requirements for air pollution control equipment, flares, and combustion devices used required to comply with Section XVII.

XVII.B.12.a. All air pollution control equipment ~~required by this Section XVII~~ shall be operated and maintained pursuant to ~~manufacturer~~ the manufacturing specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file. In addition, all such air pollution control equipment shall be adequately designed and sized to achieve the control efficiency rates ~~required by this Section XVII~~ and to handle reasonably foreseeable fluctuations in emissions of ~~volatile organic compounds VOCs and other hydrocarbons~~ during normal operations. Fluctuations in emissions that occur when the separator dumps into the tank are reasonably foreseeable.

~~XVII.B.1.b. All condensate collection, storage, processing and handling operations, regardless of size, shall be designed, operated and maintained so as to minimize leakage of volatile organic compounds to the atmosphere to the extent reasonably practicable.~~

XVII.B.12.eb. If a ~~flare or other~~ combustion device is used to control emissions of ~~volatile organic compounds to comply with Section XVII VOCs and other hydrocarbons from storage tanks subject to Section XVII.C. and glycol natural gas dehydrators subject to Section XVII.D.,~~ it shall be enclosed except as described below in Section XVII.B.2.f., have no visible emissions during normal ~~operations~~ operation, and be designed so ~~than that~~ an observer can, by means of visual observation from the outside of the enclosed flare or combustion device, or by other ~~convenient~~ means approved by the Division, determine whether it is operating properly. An owner or operator that installed a combustion device prior to [insert date of promulgation] with Division approval, either express or implied,

is not required to replace or retrofit the control device unless the combustion device is modified after [insert date of promulgation].

XVII.B.12.d. Any of the effective dates for installation of controls on ~~condensate storage~~ tanks, glycol natural gas dehydrators, and/or internal combustion engines may be extended at the ~~air pollution control~~-Division's discretion for good cause shown.

XVII.B.2.d. Auto-igniters: All combustion devices used to control emissions of hydrocarbons-VOCs from storage tanks subject to Section XVII.C. and glycol natural gas dehydrators subject to Section XVII.D. shall must be equipped with and operate an auto-igniter as follows:

XVII.B.2.d.(i) All such combustion devices installed on or after May-January 1, 20154, will must be equipped with an operational auto-igniter upon installation of the combustion device; and

XVII.B.2.d.(ii) All such combustion devices installed before May-January 1, 20154, will must be equipped with an operational auto-igniter by or before May 1, 2016, or after the next combustion device planned shutdown, whichever comes first.

XVII.B.2.e. Alternative emissions control equipment shall qualify as air pollution control equipment, and may be used in lieu of, or in combination with, combustion devices and vapor recovery units to achieve the emission reductions required by this Section XVII, if the Division approves the equipment, device or process. ~~As part of the approval process the Division, at its discretion, may specify a different control efficiency than the control efficiencies required by this Section XVII.~~

XVII.B.2.f. An owner or operator may install a non-enclosed flare that otherwise meets the requirements of XVII.B.2.b. to control volatile organic compounds as follows:

XVII.B.2.f.(i) If the flare will control emissions at a Well Production Facility, Compressor Station, or natural gas processing plant and the required design capacity exceeds the reasonably available capacity for an enclosed combustor;

XVII.B.2.f.(ii) If the flare will serve as a backup to the primary means of control;

XVII.B.2.f. (iv) If the flare is located more than 1,320 feet from a Residential Area. For purposes of this Section XVII.B.2.f., Residential Area means an area where six (6) or more occupied residential homes are within a 1,320 foot radius of the Well Production Facility, Compressor Station, or natural gas processing plant at which the flare is located. The presence of a Residential Area shall be determined at the time the non-enclosed flare is installed. Owners and operators shall not be required to replace or retrofit the non-enclosed flare in the event that a Residential Area is later established within 1,320 feet of the Well Production Facility, Compressor Station, or natural gas processing plant.

(v) An owner or operator that installed a flare subject to one of the exceptions at XVII.B.2.f.(i). through (iv). or with prior division approval, either express

or implied, is not required to retrofit or replace the flare unless modified, pursuant to Regulation 3, and a cost-benefit analysis reasonably justifies retrofit or replacement.

XVII.B.2.g. In the event that a control device is inoperable or malfunctioning, the owner or operator may choose to shut-in operations to the source or site as an air pollution control alternative, in lieu of, emergency recordkeeping and reporting requirements. Only records of the shut-in and control device maintenance must be maintained.

XVII.B.3. Requirements for compressor seals and open-ended valves or lines at natural gas compressor stations only.

XVII.B.3.a. Beginning January 1, 2015, each open-ended valve or line at ~~well production facilities and~~ natural gas compressor stations must be equipped with a cap, blind flange, plug, or a second valve that seals the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirement to seal the open end of the valve or line.

XVII.B.3.b. Beginning January 1, 2015, uncontrolled actual ~~hydrocarbon~~ VOC emissions from wet seal fluid degassing systems on wet seal centrifugal compressors at natural gas compressor stations must be reduced by at least 95%, unless the centrifugal compressor is subject to 40 C.F.R. Part 60, Subpart OOOO on that date or thereafter.

XVII.B.3.c. Beginning January 1, 2015, at natural gas compressor stations, the rod packing on any reciprocating compressor installed must be replaced every 26,000 hours of operation or every thirty six (36) months, unless the reciprocating compressor is subject to 40 C.F.R. Part 60, Subpart OOOO on that date or thereafter or if the vent gas from the rod packing is being captured, controlled or put to other beneficial use. The measurement of accumulated hours of operation (26,000) or months elapsed (36) begins on January 1, 2015.

X.V.II.B.4. Oil refineries are not subject to ~~this section of the rule~~ Section XVII.

XVII.B.4⁵. ~~Condensate tanks, Glycol natural gas~~ dehydrators and internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63, a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard ("~~NSPS~~") under 40 CFR Part 60 are not subject to ~~this~~ Section XVII.

XVII.C. (State Only) Emission reduction from ~~condensate~~ storage tanks at ~~oil and gas exploration and production operations, natural gas compressor stations, well production facilities,~~ natural gas ~~drip compressor~~ stations, and natural gas processing plants.

XVII.C.1. Control and monitoring requirements for storage tanks

XVII.C.1.a. Beginning May 1, 2008, owners or operators of all ~~atmospheric condensate~~ storage tanks ~~storing condensate~~ with uncontrolled actual emissions of ~~volatile organic compounds~~ VOCs equal to or greater than ~~twenty (20)~~ tons per year based on a rolling twelve-month total ~~shall~~ must operate air pollution control equipment that has an average control efficiency of at least 95% for VOCs ~~on such tanks.~~

XVII.C.21.b. ~~For condensate~~ Owners or operators of all storage tanks with ~~past,~~ uncontrolled actual emissions of ~~volatile organic compounds~~ VOCs of ~~lessequal to or greater than 20~~ six (6) tons per year based on a rolling twelve-month total that may become subject to Section XVII.C.1. by virtue of the addition of a newly drilled well or the recompletion or stimulation of an existing well, owners or operators of such tanks shall have until 90 days after the date of 1st production of the newly drilled, recompleted or stimulated well to install and ~~must~~ operate any required air pollution control equipment. If the owner or operator determines that emissions of volatile organic compounds will be below the 20 ton per year threshold, the owner or operator shall notify the Division of this determination in writing and include an explanation of the methodology used to make this determination. that achieves an average ~~hydrocarbon~~ VOC control efficiency of 95%. If a combustion device is used, it ~~shall~~ must have a design destruction efficiency of at least 98% for ~~hydrocarbons~~ VOCs.

XVII.C.1.b.(i) Control requirements of Section XVII.C.1.b. must be achieved in accordance with the following schedule:

XVII.C.1.b.(i)(a) A storage tank constructed on or after ~~May~~ January 1, 20145, must be in compliance ~~by~~ within ninety (90) days from the date that the storage tank commences operation.

XVII.C.1.b.(ii)(i)(b) A storage tank ~~constructed that began operating before May~~ January 1, 20154, must be in compliance by May 1, 20165.

XVII.C.1.b.(iii)(i)(de) A storage tank not otherwise subject to Sections XVII.C.1.b.(i)(a) or XVII.C.1.b.(i)(b)(ii), ~~above~~, that increases uncontrolled actual emissions to six (6) tons per year VOC or more ~~per year on a rolling twelve month basis after May~~ January 1, 20145, must be in compliance within sixty ~~days~~ (60) days of discovery of the emissions increase.

XVII.C.1.c. Control requirements within ~~ninety~~ (90) days of the date of first production.

XVII.C.1.c.(i) Beginning ~~May~~ January 1, 20145, owners or operators of storage tanks at well production facilities ~~shall~~ must collect and control emissions by routing emissions to operating air pollution control equipment during the first ~~ninety~~ (90) calendar days after the date of first production. The air pollution control equipment ~~shall~~ must achieve an average ~~hydrocarbon~~ VOC control efficiency of 95%. If a combustion device is used, it ~~shall~~ must have a design destruction efficiency of at least 98% for ~~hydrocarbons~~ VOCs. ~~Except that this~~ This control requirement does not apply to storage tanks that are ~~reasonably~~ projected to have emissions less than 1.5 tons of VOC during the first ~~ninety~~ (90) days after the date of first production.

XVII.C.1.c.(ii) The air pollution control equipment and any associated monitoring equipment required pursuant to Section XVII.C.1.c., ~~above~~(i), may be removed at any time after the first 90 calendar days as long as the source can demonstrate that uncontrolled actual emissions from the storage tank are ~~reasonably expected to be~~ below the threshold in Section XVII.C.1.b., ~~above~~.

XVII.C.2. ~~Capture requirements for storage tanks that are fitted with air pollution control equipment as required by Sections XII.D. or XVII.C.1.~~

~~XVII.C.2.a. Beginning on January 1, 2015, or the applicable compliance date specified in Section XVII.C.1.b.(i), whichever comes later, owners and operators of storage tanks shall route all hydrocarbon emissions subject to air pollution control equipment, and shall operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation unless venting is reasonably required for maintenance, gauging, or safety of personnel and equipment.~~

~~XVII.C.2.b. Beginning on the applicable compliance date specified in section XVII.C.1.b., owners and operators of storage tanks shall develop, certify, and implement a document Storage Tank Emission Management System (STEM) plan to identify appropriate strategies to minimize emissions from venting at thief hatches (or other access points to a storage tank) and pressure relief devices during normal operation. As part of STEM, owners and operators shall evaluate and employ appropriate control technologies, monitoring practices, operational practices, and/or other strategies designed to meet the requirements set forth in Section XVII.C.2.a., above, and will update the STEM plan as necessary to achieve or maintain compliance. Owners and operators are not required to develop and implement STEM for storage tanks containing only stabilized liquids. The minimum elements of STEM are listed below.~~

~~XVII.C.2.1.b.(i) STEM must include a monitoring strategy that incorporates the minimum monitoring frequency set forth in Section XVII.F.5.e., procedures for evaluating ongoing storage tank emission capture performance, and, if applicable, the selected strategies.~~

~~XVII.C.2.b.(ii) STEM must include a certification by the owner or operator that the selected STEM strategy or strategies are designed to minimize emissions from storage tanks and associated equipment components at the facility or facilities, including thief hatches and pressure relief devices.~~

~~XVII.C.3. Monitoring: The monitoring strategy of each STEM plan must include monitoring in accordance with Approved Instrument Based Monitoring Methods, as specified in Section XVII.F.5.~~

~~XVII.C.3.a. In addition to any applicable Approved Instrument Based Monitoring Methods, conduct audio, visual, olfactory ("AVO") inspection and additional visual inspections of the storage tank and any associated equipment (i.e. separator, air pollution control equipment, or other pressure reducing equipment), must be completed as often at the same frequency as liquids are loaded out from the storage tank. However, AVO inspection is These inspections are required no more frequently than every seven (7) days or less frequently than every thirty-one (31) days. AVO monitoring is not required for components and storage tanks or associated equipment that are unsafe, difficult, or inaccessible to monitor. AVO inspection, as defined in Section XVII.C.1.e. The additional visual AVO inspections must include, at a minimum:~~

~~XVII.C.3.a.1.d.(i) Visual inspection of any storage tank thief hatch, pressure relief valve, or other access point to ensure that they are enclosed and properly sealed;~~

~~XVII.C.3.a.1.d.(ii) Visual inspection or monitoring of the storage tank air pollution control equipment to ensure that it is operating, including that the pilot light is lit on combustion devices used as air pollution control equipment;~~

XVII.C.3-a.1.d.(iii) If a flare or other combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light, to ensure they are functioning properly;

XVII.C.3-a.1.d.(iv) Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the storage tank to the air pollution control equipment are open; and

XVII.C.3-1.d.(v) Monitoring: The owner or operator of any condensate storage tank that is required to control volatile organic compound emissions pursuant to this Section XVII.C. shall visually inspect or monitor the Air Pollution Control Equipment to ensure that it is operating at least as often as condensate is loaded out from the tank, unless a more frequent inspection or monitoring schedule is followed. In addition, if a (v) If a flare or other combustion device is used, the owner or operator shall visually inspect inspection of the device for the presence of or absence of smoke. If smoke is observed, either the equipment will must be immediately shut-in to investigate that the potential cause for smoke and perform repairs, as necessary, or EPA Method 22 shall must be conducted to determine whether visible emissions are present for a period of at least as often as condensate is loaded out from the tank one (1) minute in fifteen (15) minutes.

XVII.C.1.e. If equipment associated with the storage tank is unsafe, difficult, or inaccessible to monitor, the owner or operator is shall not be required to monitor such equipment until it becomes feasible to do so.

XVII.C.1.e.(i) ———Difficult to monitor equipment are those that means it cannot be monitored without elevating the monitoring personnel more than two meters above a supported surface or is unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access up to 7.6 meters (25 feet) above the ground.

XVII.C.1.e.(ii) -Unsafe to monitor means it equipment is unsafe to monitor because cannot be monitored without exposing monitoring personnel would be exposed to an imminent and potential immediate danger as a consequence of completing the monitoring.

XVII.C.1.e.(iii) -Inaccessible to monitor equipment means equipment that is buried, insulated, or obstructed by equipment or piping that prevents access to the equipment by monitoring personnel.

XVII.C.2. Capture and monitoring requirements for storage tanks that are fitted with air pollution control equipment as required by Sections XII.D. or XVII.C.1.

XVII.C.2.a. Owners or operators of storage tanks must route all hydrocarbon emissions to air pollution control equipment, and must operate without to minimize venting hydrocarbon emissions uncontrolled releases to the maximum extent practicable from the thief hatches (or other access point to the tank) or pressure relief device during normal operation, unless venting is reasonably required for maintenance, gauging, or safety of personnel and equipment. Compliance must be achieved in accordance with the schedule in Section XVII.C.2.b.(ii).

XVII.C.2.b. Beginning on January 1, 2015, or the applicable compliance date in Section XVII.C.1.b.(i), whichever comes later, Owners or operators of storage

tanks subject to control requirements of Sections XII.D.2., XVII.C.1.a. or XVII.C.1.b. must develop, certify, and implement a documented Storage Tank Emission Management System (STEM) plan to identify, evaluate, and employ appropriate control technologies, monitoring practices, operational practices, and/or other strategies designed to meet the requirements set forth in Section XVII.C.2.a. An owner or operator may develop a STEM plan applicable to multiple Storage Tanks across some or all of the owner or operators' assets and operations within Colorado. Owners or operators must update the STEM plan as necessary to achieve or maintain compliance. Owners or operators are not required to develop and implement STEM for storage tanks containing only stabilized liquids. The minimum elements of STEM are listed below.

XVII.C.2.b.(i) The STEM plan must include selected control technologies, monitoring practices, operational practices, and/or other strategies; procedures for evaluating ongoing storage tank emission capture performance; and monitoring in accordance with approved instrument based monitoring method AIMM following the applicable monitoring frequency in Table 1.

XVII.C.2.b.(ii) Owners or operators must achieve the requirements of Sections XVII.C.2.a. and XVII.C.2.b. and begin implementing the required approved instrument based monitoring AIMM method in accordance with the following schedule:

XVII.C.2.b.(ii)(a) A storage tank constructed on or after May-January 1, 20154, must comply with the requirements of Sections XVII.C.2.a. and XVII.C.2.b. by the date that the storage tank commences operation. Approved instrument based monitoring method inspections must begin within ninety (90) days after the tank commences operation.

XVII.C.2.b.(ii)(b) A storage tank constructed before May-January 1, 20154, must comply with the requirements of Sections XVII.C.2.a. and XVII.C.2.b. by May 1, 20156. Approved instrument based monitoring method inspections must begin within ninety (90) days of the Phase-In Schedule in Table 1, or within thirty (30) days for storage tanks with uncontrolled actual VOC emissions > 50 tons per year.

XVII.C.2.b.(ii)(c) A storage tank not otherwise subject to Sections XVII.C.2.b.(ii)(a) or XVII.C.2.b.(ii)(b) that increases uncontrolled actual emissions to six (6) tons per year VOC or more on a rolling twelve month basis after May-January 1, 20154, must be in compliance with Sections XVII.C.2.a. and XVII.C.2.b. and implement the required approved instrument based monitoring AIMM method within sixty (60) days of discovery of the emissions increase.

XVII.C.2.b.(ii)(d) Following the first approved instrument based monitoring method inspection, owners or operators must continue conducting approved instrument based monitoring AIMM method inspections in accordance with the Inspection Frequency in Table 1.

Table 1 – Storage Tank Inspections		
Threshold: Storage Tank Uncontrolled Actual VOC Emissions (tpy)	Approved Instrument Based Monitoring Method Inspection Frequency	Phase-In Schedule
> 6 and ≤ 12	Annually	January 1, 2016
> 12 and ≤ 50	Quarterly	July 1, 2015
> 50	Monthly	January 1, 2015

XVII.C.2.b.(iii) Owners or operators are not required to monitor storage tanks and associated equipment that are unsafe, difficult, or inaccessible to monitor, as defined in Section XVII.C.1.e.

XVII.C.2.b.(iv) STEM must include a certification by the owner or operator that the selected STEM strategy or strategies are designed to minimize emissions from storage tanks and associated equipment at the facility or facilities, including thief hatches and pressure relief devices.

XVII.C.3. Recordkeeping: The owner or operator of each condensate storage tank shall subject to Sections XII.D. or XVII.C.1.b. must maintain the following records of STEM as if applicable, including the plan, any updates, and the certification, to be made and make them available to the Division upon request. In addition, for a period of five two years, the owner or operator must maintain records of any required monitoring and make them available to the Division upon request, including:

XVII.C.43.a. ~~Monthly condensate production from the~~ The AIRS ID for the storage tank.

XVII.C.43.b. The date and duration of any period where uncontrolled releases are discovered at the storage tank thief hatch, pressure relief device, or other access point are found to be venting hydrocarbon emissions.

XVII.C.43bc. For any condensate storage tank required to be controlled pursuant to this Section XVII.C., the date, time and duration of any period where the air pollution control equipment is not operating. ~~The duration of a period of non-operation shall be from the time that the air pollution control equipment was last observed to be operating until the time the equipment recommences operation.~~

XVII.C.43.ed. ~~For tanks where~~ Where a flare or other combustion device is being used, the date and time of any instances where visible emissions are observed from the device result of any EPA Method 22 test or investigation pursuant to Section XVII.C.4.1.d.(v).

XVII.C.3.e. The timing of and efforts made to eliminate venting an uncontrolled release, restore operation of air pollution control equipment, and to mitigate visible emissions.

XVII.C.3.f. A list of equipment that identification numbers for components that are designated as unsafe, difficult, or inaccessible to monitor, as described in Section

XVII.C.1.e., an explanation stating why the equipment component is so designated, and the plan for monitoring such equipment component(s).

XVII.D. (State Only) Emission reductions from glycol natural gas dehydrators

XVII.D.1. Beginning May 1, 2008, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation a well production facility, natural gas compressor station, drip station or or natural gas gas-processing plant subject to control requirements pursuant to Section XVII.D.2., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent through the use of a condenser or air pollution control equipment.

XVII.D.2. The control requirement in Section XVII.D.1. shall apply where:

XVII.D.2.a. Actual uncontrolled emissions of volatile organic compounds from the glycol natural gas dehydrator are equal to or greater than two tons per year; and

XVII.D.2.b. The sum of actual uncontrolled emissions of volatile organic compounds from any single glycol natural gas dehydrator or grouping of glycol natural gas dehydrators at a single stationary source is equal to or greater than 15 tons per year. To determine if a grouping of dehydrators meets or exceeds the 15 tons per year threshold, sum the total actual uncontrolled emissions of volatile organic compounds from all individual dehydrators at the stationary source, including those with emissions less than two tons per year.

XVII.D.3. Beginning May 1, 2015, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, and drip station or gas-processing plant subject to control requirements pursuant to Section XVII.D.4., shall reduce uncontrolled actual emissions of hydrocarbons by at least 95 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons, except where:

XVII.D.3.a. The combustion device has been authorized by permit prior to May 1, 2014; and

XVII.D.3.b. A building unit or designated outside activity area is not located within 1,320 feet of the facility at which the natural gas glycol dehydrator is located.

XVII.D.4. The control requirement in Section XVII.D.3. shall apply where:

XVII.D.4.a. Actual uncontrolled emissions Owners or operators of volatile organic compounds from a single new a glycol natural gas dehydrator are constructed on or after May 1, 2015, with uncontrolled actual emissions of VOCs equal to or greater than two (2) tons per year must be in compliance with Section XVII.D.3. by the date that the glycol natural gas dehydrator commences operation; or

XVII.D.4.b. Actual uncontrolled Uncontrolled actual emissions of volatile organic compounds VOCs from a single existing glycol natural gas dehydrator constructed before May 1, 2015, are equal to or greater than six (6) tons per year, or two (2) tons per year if the glycol natural gas dehydrator is located within 1,320 feet of a building unit or designated outside activity area.

~~XVII.D.4.c.~~ For purposes of ~~Section~~ Sections XVII.D.3. and XVII.D.4.:

~~XVII.D.4.c.(i) Building Unit shall mean a residential building unit, and every five thousand (5,000) square feet of building floor area in commercial facilities or every fifteen thousand (15,000) square feet of building floor area in warehouses that are operating and normally occupied during working hours.~~

~~XVII.D.4.c.(ii) A designated outside activity area~~ Designated Outside Activity Area shall mean an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of public assembly owned or operated by a local government, which the local government seeks to have established as a ~~Designated Outside Activity~~ designated outside activity area by the COGCC Area; or an outdoor venue or recreation area where ingress to or egress from could be impeded in the event of an emergency condition at an oil and gas location less than three hundred and fifty (350) feet from the venue due to the configuration of the venue and the number of persons known or expected to simultaneously occupy the venue on a regular basis.

XVII.E. Control of emissions from new, modified, existing, and relocated natural gas fired reciprocating internal combustion engines.

XVII.E.1. (State Only) The requirements of this Section XVII.E. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.2. (State Only) New, Modified and Relocated Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.2.a. Except as provided in Section XVII.E.2.b. below, the owner or operator ~~and~~ any natural gas fired reciprocating internal combustion engine that is either constructed or relocated to the state of Colorado from another state, on or after the date listed in the table below shall operate and maintain each engine according to the manufacturer's written instructions or procedures to the extent practicable and consistent with technological limitations and good engineering and maintenance practices over the entire life of the engine so that it achieves the emission standards required in Section XVII.E.2.b. Table ~~12~~ below.

XVII.E.2.b. Actual emissions from natural gas fired reciprocating internal combustion engines shall not exceed the emission performance standards in Table ~~12~~ below as expressed in units of grams per horsepower-hour (G/hp-hr)

TABLE 12				
Maximum Engine Hp	Construction or Relocation Date	Emission Standards is G/hp-hr		
		NOx	CO	VOC
< 100 Hp	Any	NA	NA	NA
≥100 Hp	On or after January 1, 2008	2.0	4.0	1.0

and < 500 Hp	On or after January 1, 2011	1.0	2.0	0.7
≥500 Hp	On or after July 1, 2007	2.0	4.0	1.0
	On or after July 1, 2010	1.0	2.0	0.7

XVII.E.3. Existing Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.3.a. (Regional Haze SIP) Rich Burn Reciprocating Internal Combustion Engines

XVII.E.3.a.(i) Except as provided in Sections XVII.3.1.(i)(b) and (c) and XVII.E.3.a.(ii), all rich burn reciprocating internal combustion engines with a manufacturer's name plate design rate greater than 500 horsepower, constructed or modified before February 1, 2009 shall install and operate both a non-selective catalytic reduction system and an air fuel controller by July 1, 2010. A rich burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of less than 2% by volume.

XVII.E.3.a.(i)(a) All control equipment required by this Section XVII.E.3.a. shall be operated and maintained pursuant to manufacturer specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file.

XVII.E.3.a.(i)(b) Internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63, a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard under 40 CFR Part 60 are not subject to this Section XVII.E.3.a.

XVII.E.3.a.(i)(c) The requirements of this Section XVII.E.3.a. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.3.a.(ii) Any rich burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than \$ 5,000 per ton of combined volatile organic compound and nitrogen oxides emission reductions (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.a. Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

XVII.E.3.b. (State Only) Lean Burn Reciprocating Internal Combustion Engines

XVII.E.3.b.(i) Except as provided in Section XVII.E.3.b.(ii), all lean burn reciprocating internal combustion engines with a manufacturer's nameplate design rate greater than 500 horsepower shall install and operate an oxidation catalyst by July 1, 2010. A lean burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of 2% by volume, or greater.

XVII.E.3.b.(ii) Any lean burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than \$ 5,000 per ton of volatile organic compound emission reduction (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.b.(i). Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

XVII.F. (State Only) Leak detection and repair program for components at well production facilities, storage tanks, and natural gas compressor stations, excluding storage tank thief hatches, pressure relief devices, and access points subject to STEM. Natural gas processing plants, including Components, Storage Tanks and Compressor Stations at natural gas processing plants, are not subject to this Section XVII.F.

XVII.F.1. Beginning January 1, 2015, the date the well production facility or natural gas compressor station becomes subject to this Section XVII.F., owners and/or operators of components at well production facilities and/or natural gas compressor stations will must identify and repair leaks from such components at these facilities in accordance with the requirements of this Section XVII.F. The following provisions of Section XVII.F. shall apply in lieu of any directed inspection and maintenance program requirements established pursuant to Regulation Number 3, Part B, Section III.D.2.

XVII.F.2. Owners and/or operators of components at well production facilities or natural gas compressor stations that monitor components as part of this Section XVII.F. may opt to estimate uncontrolled actual emissions from components for the purpose of evaluating the applicability of component fugitive emissions to Regulation Number 3 by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017).

XVII.F.3. Owners and/or operators of well production facilities or natural gas compressor stations shall utilize must implement the Approved Instrument Based Monitoring Method approved instrument based monitoring method and AVO program inspections as outlined in Section XVII.F. AVO monitoring is not required for components and tanks that are unsafe to monitor, difficult, or inaccessible to monitor, pursuant to as defined in Section XVII.F.5.g6.

XVII.F.3. If upon the completion of four consecutive semi-annual AIMM inspection events, no leaks requiring repair are detected, AIMM inspection shall be conducted annually for that well production facility or natural gas compressor station. If upon the completion of four consecutive quarterly AIMM inspection events, no leaks requiring repair are detected, AIMM inspection shall be conducted semi-annually for that well production facility or natural gas compressor station. If two or more leaks requiring repair are

detected during subsequent AIMM inspection events, then the inspection frequency shall revert back to the original frequency for that well production facility or natural gas compressor station until the terms of this provision are again met.

XVII.F.3.a. An owner or operator may skip the next AIMM inspection event where the owner or operator demonstrates in the previous AIMM inspection event that less than or equal to 2 percent of components required repair for all well production facilities or natural gas compressor stations in a basin belonging to the same threshold class as set forth in Tables 2 and 3. An owner or operator may estimate a facility's component count using the Default Average Component Counts in 40 CFR Part 98, Subpart W, Tables W-1B and W-1C for equipment located at natural gas production facilities and oil production facilities, respectively.

~~XVII.F.4. Inspection schedules for natural gas compressor stations: Beginning January 1, 2015, owners and~~ Leak detection for components at natural gas compressor stations.

XVII.F.4.a. Beginning January 1, 2016, within 180 days of startup of a new natural gas compressor station, Owners or operators of natural gas compressor stations shall must inspect components for leaks using an Approved Instrument Based Monitoring Method approved instrument based monitoring AIMM method, in accordance with the following Table 23, except under the conditions described in XVII.F.6. for components subject to that are unsafe, difficult, or inaccessible to monitor, as defined in Section XVII.F.5.g6.

XVII.F.4.b. Owners or operators of existing natural gas compressor stations shall inspect components for leaks as set forth in Table 3, except under the conditions described in Section XVII.F.6.

XVII.F.4.c. –For purposes of this Section XVII.F.4., fugitive VOC emissions shall must be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), or for other Division approved method.

Table 2 <u>Table 3</u> Compressor Station Component Inspections		
<u>Fugitive VOC Emissions (tpy)</u>	<u>AIMM Inspection Frequency (calendar basis)</u>	<u>Beginning of Phase-In Schedule for Existing Compressor Stations¹</u>
<u>> 2 and < 6</u>	<u>One time, within five years of applicable phase-in or implementation date</u>	<u>July 1, 2016</u>
<u>> 60 and < 2012</u>	<u>Annually</u>	<u>January 1, 2016</u>
<u>> 12-20 and < 50</u>	<u>QuarterlySemi-annually</u>	<u>July 1, 2015</u>
<u>> 50</u>	<u>MonthlyQuarterly</u>	<u>January 1, 2015</u>

¹ As set forth in XVII.F.4.a., owners and operators of new Compressor Stations shall initiate compliance with this Table 2 within 180 days after the commenced construction date (i.e., the implementation date).

~~XVII.F.5. Requirements~~ Leak detection for components at ~~for well production facilities~~
~~and/or storage tanks~~

~~XVII.F.5.a. Beginning August 1, 2014, all new~~All well production facilities
~~shall~~constructed on or after August 1, 2014, must have a documented pressure
~~test performed on all equipment and piping prior to start up. Documentation of~~
~~this 90 day testing and monitoring shall~~initial pressure test must be provided in
~~the first annual report to the Division, as required by Section XVII.F.910.~~

~~XVII.F.5.ab. Beginning January 1, 2015, within 90 days of startup of all new~~Owners or
~~operators of well production facilities and/or storage tanks, owners and/or~~
~~operators shall~~constructed on or after January 1, 2015~~6~~, must ~~identify~~inspect
components for leaks using as set forth in Table 4 no later than 180 days after
the date of first production, except under the conditions described in Section
~~XVII.F.6. and repair leaks from components using an Approved Instrument Based~~
~~Monitoring Method. Such action shall qualify as an inspection pursuant to~~
~~approved instrument based monitoring method within ninety (90) days after the~~
~~inspection frequency~~facility commences operation and in accordance with the
~~Inspection Frequency schedule in Table 3. To the extent that pursuant to Table~~
4 an AIMM inspection and an AVO monitoring would occur simultaneously, then
the AIMM inspection satisfies the requirement to conduct AVO for that inspection.

4. ~~XVII.F.5.c. Consistent with the provisions of XVII.F.5.f., owners and~~Owners or
~~operators of existing well production facilities and/or storage tanks shall identify~~
~~and repair leaks using an Approved Instrument Based Monitoring Method, in~~
~~accordance with the implementation schedule in XVII.F.5.e. Inspection~~
~~frequency shall be determined according to Table 3.~~

~~XVII.F.5.d. Consistent with the provisions of XVII.F.5.f., owners and operators of~~
~~new well production facilities and/or storage tanks shall identify and repair~~
~~constructed before January 1, 2016~~5, must ~~identify~~inspect components for ~~leaks~~
as set forth in Table 4, except under the conditions described in Section
~~XVII.F.6. from components using an Approved Instrument Based Monitoring~~
~~Method beginning on January 1, 2015. approved instrument based monitoring~~
~~method within ninety (90) days of the Phase-In Schedule in Table 4. within thirty~~
~~(30) days for > 50 tons per year, or by July 1, 2016, for > 0 and < 6 tons per year~~
~~tanks. Thereafter, approved instrument based monitoring method and AVO~~
~~inspections must be conducted in accordance with the Inspection frequency shall~~
~~be determined according to Frequency in Table 34. To the extent that pursuant~~
to Table 4 an AIMM inspection and an AVO monitoring would occur
simultaneously, then the AIMM inspection satisfies the requirement to conduct
AVO for that inspection.

~~XVII.F.5.ed. For purposes of this Section XVII.F.5., the VOC thresholds shall be~~
~~calculated using the estimated uncontrolled actual emissions from the largest~~
~~single storage tanks as set forth in Table 4. determine the frequency at which~~
~~inspections must be performed. If no storage tanks storing oil or condensate are~~
~~located at the well production facility or multi-well site, owners or operators~~
~~will must rely on~~ VOC thresholds shall be calculated using the potential to emit of
VOC for all of the emissions sources, including emissions from components
located at the ~~facility.~~

~~XVII.F.5.e. All components at a~~ Inspection of components at a ~~well production facility or~~
~~storage tank must be inspected~~shall be conducted as set forth in Table 4:

~~Table 3~~Table 4
—Well Production Facility Component Inspections

Exhibit A
To the Joint Industry Work Group Rebuttal Statement

<u>VOC Threshold (per XVII.F.5.ed.) VOC Emissions (tpy, uncontrolled actual for sites with tanks or PTE for sites without tanks)</u>	<u>AIMM Inspection Frequency (calendar basis)</u>	<u>AVO Monitoring Frequency (calendar basis)</u>	<u>Beginning of Phase-In Schedule For Existing Well Production Facilities²</u>
<u>> 2 and < 6</u>	<u>One time, within five years of phase-in or implementation date using Approved Instrument Based Monitoring Method approved instrument based monitoring methods and thereafter using monthly AVO</u>	<u>Annual</u>	<u>July 1, 2016</u>
<u>> 6 and < 1220</u>	<u>Annually with monthly AVO</u>	<u>Semi-annual</u>	<u>January 1, 2016</u>
<u>> 12-20 and < 50</u>	<u>Quarterly with monthly AVO Semi-annually</u>	<u>Quarterly</u>	<u>July 1, 2015</u>
<u>> 50</u>	<u>Monthly Quarterly</u>	<u>Monthly</u>	<u>January 1, 2015</u>
<u>MultiWell production facilities or multi-well sites without storage tanks after April 15, 2014, storing oil or condensate that have a PTE potential to emit > 20 tpy VOC</u>	<u>Monthly Quarterly</u>	<u>Monthly</u>	<u>January 1, 2015</u>

XVII.F.5.f. Phase-in of Approved Instrument Based Monitoring Methods: Owners and operators of existing well production facilities and/or storage tanks shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method, in accordance with the following schedule:

XVII.F.5.f.(i) Beginning January 1, 2015, facilities with uncontrolled actual VOC emissions greater than 50 tpy or multi-well sites.

XVII.F.5.f.(ii) Beginning July 1, 2015, facilities with uncontrolled actual VOC emissions greater than 20 tpy but less than or equal to 50 tpy.

XVII.F.5.f.(iii) Beginning January 1, 2016, facilities with uncontrolled actual VOC emissions greater than 6 tpy but less than or equal to 20 tpy.

XVII.F.5.g.(iv) By July 1, 2016, facilities with uncontrolled actual VOC emissions less than or equal to 6 tpy.

XVII.F.5.g.XVII.F.6. If a component is unsafe, difficult, unsafe, or inaccessible to monitor, the owner or operator shall not be required to monitor the component or equipment until it becomes feasible to do so.

² As set forth in XVII.F.6.a., owners and operators of new Well Production Facilities installed after January 1, 2016 shall comply with this Table 3 within 180 days after the Date of First Production (i.e., the implementation date).

XVII.F.5-g.(i)6.a. Difficult to monitor components or equipment are those that cannot be monitored without elevating the monitoring personnel more than two (2) meters above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

XVII.F.5-g.(ii)6.b. Unsafe to monitor means a component or equipment that is unsafe because inspecting ~~are those that cannot be monitored without exposing monitoring personnel~~ would be exposed to an immediate danger as a consequence of completing the monitoring, which includes weather conditions preventing access to the site, or that endanger monitoring personnel or equipment, or prevent use of AIMM (such as reflection due to precipitation).

XVII.F.5-g.(iii)6.c. Inaccessible to monitor components or equipment are those that are buried, insulated in a manner that prevents access to the components by a monitor probe, or obstructed by equipment or piping that prevents AIMM inspection or AVO monitoring access to the components by ~~a monitor probe~~ monitoring personnel.

XVII.F.67 Leaks ~~detection~~ requiring repair: Leaks at components that are not otherwise designed to leak ~~shall~~ must be identified utilizing the methods listed in this Section ~~XVII.F.6.a. through XVII.F.6.d7.~~ Only leaks detected pursuant to this Section ~~XVIII.XVII.F.6. shall~~ 7, require repair under Section XVII.F.8.

XVII.F.67.a. For EPA Method 21 or other quantitative AIMMs, monitoring at existing well production facilities and natural gas compressor stations constructed before May January 1, 20154, a leak is any concentration of VOC above 10,000ppm hydrocarbon above 2,000 parts per million (ppm), except for existing well production facilities where a leak is defined as any concentration of hydrocarbon above 500 ppm.

XVII.F.67.b. For EPA Method 21 monitoring at facilities constructed on or after May 1, 2014, a leak is any concentration of hydrocarbon above 500 ppm.

XVII.F.67.c. For infra-red camera and AVO monitoring or other non-quantitative AIMMs such as Infra-red camera, a leak is any detectable VOC emissions except as described in XVII.F.7.d emissions not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

XVII.F.67.d. For other Division approved monitoring devices or methods, leak identification requiring repair will be established as set forth in the Division's approval.

XVII.F.7.d For leaks identified using AVO, or other non-quantitative AIMM, owners and operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section XVII.F.8. or conducting follow-up monitoring using EPA Method 21 within fifteen (15) working days of the day the leak was detected. If the follow-up EPA Method 21 monitoring shows that the leak concentration is less than or equal to 10,000 ppm volatile organic compound for well production facilities or natural gas compressor stations, then the emissions shall not be considered a leak for purposes of this Section and shall not require repair.

XVII.F.7.e. If a leak is identified using AIMM or AVO and the leak is immediately repaired (within the same working day), any such leak does not constitute a leak under this Section XVII.F.7. and is not subject to the Repair and Re-monitoring or Recordkeeping and Reporting requirements at Sections XVII.F.8. through XVII.F.10.

XVII.F.78. Repair and remonitoring

XVII.F.78.a. First attempt to repair a leak that requires repair pursuant to XVII.F.7. shall must be made no later than ~~five~~ fifteen (15) working days after discovery, unless parts are unavailable, the equipment requires shutdown to complete repair, or other good cause exists. If parts are unavailable, they shall must be ordered promptly and the repair shall must be made within ~~fifteen~~ thirty (15)30 working days of receipt of the parts. If shutdown is required, the leak shall must be repaired during the next scheduled shutdown. If delay is attributable to other good cause, repairs shall must be completed within ~~fifteen~~ thirty (30)15 working days after the owner or operator has reason to believe the cause of delay ceases to exist.

XVII.F.78.b. Within ~~fifteen~~ thirty (30)15 working days of completion of a repair, the leaks shall leak that is repaired according to Section XVII.F.7. must be remonitored to verify the repair was effective utilizing AIMM.

XVII.F.78.c. Leaks discovered pursuant to the leak detection methods of Section XVII.F.7. shall not be a violation of the Air Quality Control Commission's Rules or subject to enforcement by the Division unless the owner or operator fails to perform the required repairs in accordance with Section XVII.F.78.

XVII.F.7.d. For leaks identified using an ~~Approved Instrument Based Monitoring Method~~ approved instrument based monitoring method, owners and/or operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section XVII.F.78. or conducting follow-up monitoring using EPA Method 21 within five (5) working days of the leak ~~detected~~ detection. If the follow-up EPA Method 21 monitoring shows that the leak concentration is less than or equal to 2,000 ppm hydrocarbon for existing facilities (other than existing well production facilities), or 500 ppm for new facilities or existing well production facilities, then the emission shall not be considered is a leak for purposes of this as defined in Section XVII.F.7., the leak must be repaired and remonitored in accordance with Section XVII.F.8.

XVII.F.89. Recordkeeping: The owner or operator of each well production facility or natural gas compressor station subject to the ~~inspection~~ leak detection and ~~maintenance~~ repair requirements in this Section XVII.F. shall must maintain the following records for a period of two (2) years and make them available to the Division upon request.

XVII.F.89.a. Documentation of the pre-start-up pressure tests for new well production facilities;

XVII.F.89.ab. The date and site information for each inspection;

XVII.F.89.cb. A list of the leaking components and the monitoring method used to determine the presence of the leak;

XVII.F.89.cd. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;

~~XVII.F.89.de.~~ The date the leak was ~~repair~~repaired;

~~XVII.F.89.df.~~ The delayed repair list including the basis for placing leaks on the list;

~~XVII.F.89.fg.~~ The date the leak was remonitored to verify the effectiveness of the repair, and the results of the remonitoring; and

~~XVII.F.89.gh.~~ A list of ~~identification numbers for~~ components that are designated as unsafe, difficult, or inaccessible to monitor, as described in Section XVII.F.5-g6., and an explanation ~~for each component~~ stating why the component is so designated, ~~and the plan for monitoring such component(s).~~

~~XVII.F.910.~~ Reporting: The owner or operator of each well production facility and natural gas compressor station subject to the ~~inspectionleak detection and maintenancerepair~~ requirements in this Section XVII.F. ~~shallmust~~ submit a single annual report on or before ~~April 30thMay 31st~~ of each year summarizing that includes the following information regarding inspection and maintenance ~~inspectionleak detection and maintenancerepair~~ activities at all of their subject facilities during the previous calendar year. ~~This report shallmust contain, at a minimum, the following information:~~

~~XVII.F.910.a.~~ The number of facilities inspected;

~~XVII.F.910.b.~~ The total number of inspections;

~~XVII.F.910.c.~~ The total number of leaks identified that require repair, broken out by component type;

~~XVII.F.910.d.~~ The total number of leaks repaired;

~~XVII.F.910.e.~~ The number of leaks on the delayed repair list as of December 31st; and

~~XVII.F.910.f.~~ Each report shall be accompanied by a self-certification form. The form shall contain a certification by an authorized representative ~~responsible official of~~ the truth, accuracy, and completeness of such form, report, or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

XVII.G. (State Only) Control of emissions from well production facilities

~~XVII.G.1. Well Operation and Maintenance:~~ On or after August 1, 2014, during normal ~~operation~~ gas coming off a separator, produced during normal operation from any newly constructed, hydraulically fractured, or recompleted oil and gas well must either be routed to a gas gathering line or controlled from the date of first production by air pollution control equipment that achieves an average hydrocarbon-VOC control efficiency of 95% ~~from the date of first production.%. If a combustion device is used, it shallmust have a~~ design destruction efficiency ~~effor~~ at least 98% of ~~hydrocarbonsVOCs.~~

XVII.H. (State Only) Venting during downhole well maintenance and unloading events

~~XVII.H.1. Well Maintenance:~~ Beginning May 1, 2014, hydrocarbon emissions from flowing wells must be captured or controlled during downhole well maintenance or servicing activities, unless venting is necessary for safety.

~~XVII.H.1.a. Operators shall~~ Owners or operators must use best management practices to minimize the need for well venting associated with downhole well

~~maintenance and liquids unloading. During liquids unloading events, any means of creating differential pressure will must first be used to attempt to unload the liquids from the well without venting. If these methods are not successful in unloading the liquids from the well, the well may be vented to the atmosphere to create the necessary differential pressure to bring the liquids to the surface.~~

~~XVII.H.1.b. Venting will must be minimized to the extent possible, using best management practices during the well maintenance and liquids unloading events in XVII.H.1.a. The owner and/or operator shall must be present on-site during any planned well maintenance and liquids unloading event in XVII.H.1.a. and shall must ensure that any venting to the atmosphere is limited to the maximum extent practicable.~~

~~XVII.H.1.c. Records of the cause, date, time, and duration of venting events under this Section XVII.H. will must be kept and made available to the Division upon request.~~

XVIII. (State Only) Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations ~~in the 8-Hour Ozone Control Area or Any Ozone Nonattainment or Attainment/Maintenance Area~~

XVIII.A. Applicability

This section applies to pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: ~~oil and gas exploration and production operations well production facilities, and~~ natural gas compressor ~~stations, and/or natural gas drip~~ stations) ~~in the 8-Hour Ozone Control Area or any Ozone Nonattainment or Attainment/Maintenance Area.~~

XVIII.B. Definitions

XVIII.B.1. "Affected Operations" shall mean pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: ~~oil and gas exploration and production operations well production facilities, and~~ natural gas compressor ~~stations, and/or natural gas drip~~ stations).

XVIII.B.2. "Enhanced Maintenance" is specific to high-bleed devices and shall include but is not limited to cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; and eliminating unnecessary valve positioners.

XVIII.B.3. "High-Bleed Pneumatic Controller" shall mean a pneumatic controller that is designed to have a constant bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.

XVIII.B.4. "Low-Bleed Pneumatic controller" shall mean a pneumatic controller that is designed to have a constant bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.

XVIII.B.5. "Natural Gas Processing Plant" shall mean any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

~~XVIII.B.6. "No-bleedBleed Pneumatic Controller" shall mean any pneumatic controller that is not using hydrocarbon gas as the valve's actuating gas.~~

XVIII.B.67. "Pneumatic Controller" shall mean a continuous bleed instrument that is actuated using natural pressurized gas pressure and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow and temperature.

XVIII.C. Emission Reduction Requirements

The owners and operators of affected operations shall reduce emissions of volatile organic compounds from pneumatic controllers associated with affected operations as follows:

XVIII.C.1. In the 8-Hour Ozone Control Area:

XVIII.C.1.a. All pneumatic controllers placed in service on or after February 1, 2009, shall emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.31.c.

XVIII.C.21.b. All high-bleed pneumatic controllers in service prior to February 1, 2009 shall be replaced or retrofit such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, by May 1, 2009, unless allowed pursuant to Section XVIII.C.31.c.

XVIII.C.31.c. All high-bleed pneumatic controllers that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.31.ac.(i) For high-bleed pneumatic controllers in service prior to February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and /or process purposes by March 1, 2009. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.31.bc.(ii) For high-bleed pneumatic controllers placed in service on or after February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and /or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt. XVIII.D. Monitoring

XVIII.C.2. Statewide:

XVIII.C.2.a. All continuous bleed pneumatic controllers placed in service on or after May 1, 2014, shall:

XVIII.C.2.ca.(i) Emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.; or

XVIII.C.2.ca.(ii) Where the operator is using on-site electrical grid power and where use of Utilize no-bleed pneumatic controllers where on-site electrical grid power is being used and is technically and economically feasible, operators shall employ no-bleed pneumatic controllers. Nothing in this provision shall require an operator to bring electrical grid power to the location in order to meet this requirement or replace or retrofit low-bleed pneumatic controllers upon availability of electrical grid power to the location.

XVIII.C.2.b. All high-bleed pneumatic controllers in service prior to May 1, 2014, shall be replaced or retrofitted by May 1, 2015, such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.

XVIII.C.2.c. All high-bleed pneumatic controllers that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.2.c.(i) ~~All~~For high-bleed pneumatic controllers in service prior to May 1, 2014, the owner/operator shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and/or process purposes by March 1, 2015. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.2.c.(ii) For high-bleed pneumatic controllers placed in service on or after May 1, 2014, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and/or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.D. Monitoring

This section applies only to high-bleed pneumatic controllers identified in ~~Section~~Sections XVIII.C.~~31.c.~~ and XVIII.C.2.c.

XVIII.D.1. In the 8-Hour Ozone Control Area

XVIII.D.1.a. Effective May 1, 2009, each high-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.~~21.b.~~ Effective May 1, 2009, each high-bleed pneumatic controller shall be inspected on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2~~1.a.~~ and maintain the device according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.D.2. Statewide:

XVIII.D.2.a. Effective May 1, 2015, each high-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.2.b. Effective May 1, 2015, each high-bleed pneumatic controller shall be inspected on a monthly basis, ~~perform~~undergo necessary enhanced maintenance as defined in Section XVIII.B.2, and ~~maintain the device~~be maintained according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.E. Recordkeeping

Exhibit A
To the Joint Industry Work Group Rebuttal Statement

This section applies only to high-bleed pneumatic controllers identified in ~~Section~~Sections XVIII.C.~~31.c.~~and XVIII.C.2.c.

- XVIII.E.1. The owner or operator of affected operations shall maintain a log of the total number of high-bleed pneumatic controllers and their associated controller numbers per facility, the total number of high-bleed pneumatic controllers per company and the associated justification that the high-bleed pneumatic controllers must be used pursuant to ~~Section~~Sections XVIII.C.~~31.c.~~and XVIII.C.2.c. The log shall be updated on a monthly basis.
- XVIII.E.2. The owner or operator shall maintain a log of enhanced maintenance which shall include, at a minimum, inspection dates, the date of the maintenance activity, high-bleed pneumatic controller number, description of the maintenance performed, results and date of any corrective action taken, and the printed name and signature of the individual performing the maintenance. The log shall be updated on a monthly basis.
- XVIII.E.3. Records of enhanced maintenance of pneumatic controllers shall be maintained for a minimum of three years and readily made available to the ~~division~~Division upon request.

>>>>>>>

**DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT
Air Quality Control Commission**

REGULATION NUMBER 7

**CONTROL OF OZONE VIA OZONE PRECURSORS AND CONTROL OF
HYDROCARBONS VIA OIL AND GAS EMISSIONS**

(EMISSIONS OF VOLATILE ORGANIC COMPOUNDS AND NITROGEN OXIDES)

5 CCR 1001-9

>>>>>>>>

II. General Provisions

>>>>>>>>

II.B. Exemptions

Emissions of the organic compounds listed as having negligible photochemical reactivity in the common provisions definition of Negligibly Reactive Volatile Organic Compound are exempt from the provisions of this regulation.

(State Only) Notwithstanding the foregoing exemption, hydrocarbon emissions from oil and gas operations, including methane and ethane, are subject to this regulation as set forth in Sections XVII. and XVIII.

>>>>>>>>

**XVII. (State Only, except Section XVII.E.3.a. which was submitted as part of the Regional Haze SIP)
Statewide Controls for Oil and Gas Operations and Natural Gas-Fired Reciprocating Internal
Combustion Engines**

XVII.A. (State Only) Definitions

XVII.A.1 "Air Pollution Control Equipment," as used in this Section XVII, means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment and pollution prevention devices and processes intended to reduce uncontrolled actual emissions that comply with the requirements of Section XVII.B.2.e.

XVII.A.2. "Approved Instrument Based Monitoring Method," as used in this Section XVII. means an infra-red camera, Method 21, or other Division approved instrument based monitoring device or method. If an owner/operator elects to use a Division approved

Continuous Emission Monitoring program, the Division may approve a streamlined inspection and reporting program for such operations. Any instrument based monitoring method approved by the Division under this definition must be at least as effective as Method 21 or an infra-red camera.

- XVII.A.3. "Auto-Igniter" means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust volatile organic compound emissions.
- XVII.A.4. "Component" means each pump seal, compressor seal, flange, pressure relief device, connector, open ended line, and valve that contains or contacts a process stream with hydrocarbons. Process streams consisting of glycol, amine, produced water, or methanol are not components for purposes of this Section XVII.
- XVII.A.5. "Connector" means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Jointed fittings welded completely around the circumference of the interface are not considered connectors.
- XVII.A.6. "Date of First Production" means the date reported to the COGCC as the "first date of production."
- XVII.A.7. "Glycol Natural Gas Dehydrator" means any device in which a liquid glycol (including ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.
- XVII.A.8. "Multi-Well Site" means a common well pad from which multiple wells may be drilled to various bottomhole locations.
- XVII.A.9. "Natural Gas Compressor Station" means a facility which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure and recompress natural gas prior to processing, as well as well as compressors located downstream of processing plants.
- XVII.A.10. "Normal Operation" means all periods of operation, excluding malfunctions as defined in Section I.G. of the Common Provisions regulation. For storage tanks at well production facilities, normal operation includes but is not limited to liquid dumps from the separator.
- XVII.A.11. "Stabilized" when used to refer to crude oil, condensate, intermediate hydrocarbon liquids, or produced water means that the vapor pressure of the liquid is sufficiently low to prevent the production of vapor phase upon transferring the liquid to an atmospheric pressure in a storage tank, and that any emissions that occur are limited to those commonly referred to within the industry as working, breathing, and standing losses.

XVII.A.12. "Storage Tank" means any fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. Storage vessel is as defined in 40 CFR Part 60, Subpart OOOO. Storage tanks may be located at a well production facility or other location.

XVII.A.13. "Unsafe to Monitor" means a component is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of such monitoring.

XVII.A.14. "Visible Emissions" means observations of smoke for any period or periods of duration greater than or equal to one (1) minute in any fifteen (15) minute period during normal operation. Visible emissions do not include radiant energy or water vapor.

XVII.A.15. "Well Production Facility" means all equipment at a single stationary source directly associated with one or more oil wells or gas wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

XVII.B. (State Only) General Provisions

XVII.B.1. General requirements for prevention of emissions and good air pollution control practices for all oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.

XVII.B.1.a. All intermediate hydrocarbon liquids collection, storage, processing, and handling operations, regardless of size, shall be designed, operated, and maintained so as to minimize leakage of volatile organic compounds to the atmosphere to the extent reasonably practicable.

XVII.B.1.b. At all times, including periods of start-up and shutdown, the facility and air pollution control equipment shall be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether or not acceptable operating and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

XVII.B.2. General requirements for air pollution control equipment, flares, and combustion devices used to comply with Section XVII.

XVII.B.2.a. All air pollution control equipment shall be operated and maintained pursuant to the manufacturing specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file. In addition, all such air pollution control equipment shall be adequately designed and sized to achieve the control efficiency rates and to handle reasonably foreseeable fluctuations in emissions of volatile organic compounds and hydrocarbons during normal operations. Fluctuations in emissions that occur when the separator dumps into the tank are reasonably foreseeable.

XVII.B.2.b. If a flare or other combustion device is used to control emissions of hydrocarbons, it shall be enclosed, have no visible emissions during normal operations, and be designed so that an observer can, by means of visual observation from the outside of the enclosed flare or combustion device, or by other means approved by the Division, determine whether it is operating properly.

XVII.B.2.c. Any of the effective dates for installation of controls on storage tanks, dehydrators, and/or internal combustion engines may be extended at the Division's discretion for good cause shown.

XVII.B.2.d. Auto-igniters: All combustion devices used to control emissions of hydrocarbons shall be equipped with and operate an auto-igniter as follows:

XVII.B.2.d.(i) All combustion devices installed on or after May 1, 2014, will be equipped with an operational auto-igniter upon installation of the combustion device.

XVII.B.2.d.(ii) All combustion devices installed before May 1, 2014, will be equipped with an operational auto-igniter by or before May 1, 2015⁶, or after the next combustion device planned shutdown, whichever comes first.

XVII.B.2.e. Alternative emissions control equipment shall qualify as air pollution control equipment, and may be used in lieu of, or in combination with, combustion devices and vapor recovery units to achieve the emission reductions required by this Section XVII, if the Division approves the equipment, device or process. As part of the approval process the Division, at its discretion, may specify a different control efficiency than the control efficiencies required by this Section XVII.

XVII.B.3. Oil refineries are not subject to Section XVII.

XVII.B.4. Glycol natural gas dehydrators and internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63, a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard ("NSPS") under 40 CFR Part 60 are not subject to this Section XVII.

XVII.C. (State Only) Emission reduction from storage tanks at oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.

XVII.C.1. Control requirements for storage tanks

XVII.C.1.a. Beginning May 1, 2008, owners or operators of all storage tanks storing condensate with uncontrolled actual emissions of volatile organic compounds equal to or greater than twenty (20) tons per year based on a rolling twelve-month total must operate air pollution control equipment that has an average control efficiency of at least 95% for VOCs.

XVII.C.1.b. Owners or operators of all storage tanks with uncontrolled actual emissions of volatile organic compounds equal to or greater than six (6) tons per year based on a rolling twelve-month total must operate air pollution control equipment that achieves an average hydrocarbon control efficiency of 95%. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons.

XVII.C.1.b.(i) A storage tank constructed on or after May 1, 2014, must be in compliance by the date that the storage tank commences operation.

XVII.C.1.b.(ii) A storage tank constructed before May 1, 2014, must be in compliance by May 1, 2015.

XVII.C.1.b.(iii) A storage tank not otherwise subject to Sections XVII.C.1.b.(i) or XVII.C.1.b.(ii), above, that increases uncontrolled actual emissions to six tons VOC or more per year on a rolling twelve month basis after May 1, 2014, must be in compliance within sixty days of discovery of the emissions increase.

XVII.C.1.c. Control requirements within 90 days of the date of first production.

XVII.C.1.c.(i) Beginning May 1, 2014, owners or operators of storage tanks at well production facilities shall collect and control emissions by routing emissions to operating air pollution control equipment during the first 90 calendar days after the date of first production. The air pollution control equipment shall achieve an average hydrocarbon control efficiency of 95%. If a combustion device is used, it shall have a design

destruction efficiency of at least 98% for hydrocarbons. Except that this requirement does not apply where the Division has approved a demonstration that the storage tanks that are projected to will have emissions less than 1.5 tons of VOC during the first 90 days after the date of first production.

XVII.C.1.c.(ii) The air pollution control equipment and any associated monitoring equipment required pursuant to Section XVII.C.1.c., above, may be removed at any time after the first 90 calendar days as long as the source can demonstrate that uncontrolled actual emissions from the storage tank are below the threshold in Section XVII.C.1.b., above.

XVII.C.2. Capture requirements for storage tanks that are fitted with air pollution control equipment as required by Sections XII.D. or XVII.C.1.

XVII.C.2.a. Beginning on the applicable compliance date specified in Section XVII.C.1.b., owners and operators of storage tanks shall route all hydrocarbon emissions to air pollution control equipment, and shall operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation unless venting is reasonably required for maintenance, gauging, or safety of personnel and equipment.

XVII.C.2.b. Beginning on the applicable compliance date specified in section XVII.C.1.b., owners and operators of storage tanks shall develop, certify, and implement a document Storage Tank Emission Management System (STEM) plan to identify appropriate strategies designed to meet the requirements of XVII.C.2.a. minimize emissions from venting at thief hatches (or other access points to a storage tank) and pressure relief devices during normal operation. As part of STEM, owners and operators shall evaluate and employ appropriate control technologies, monitoring practices, operational practices, and/or other strategies designed to meet the requirements set forth in Section XVII.C.2.a., above, and will update the STEM plan as necessary to achieve or maintain compliance. Owners and operators are not required to develop and implement STEM for storage tanks containing only stabilized liquids. The minimum elements of STEM are listed below.

XVII.C.2.b.(i) STEM must include a monitoring strategy that incorporates the minimum monitoring frequency set forth in Section XVII.F.5.e., procedures for evaluating ongoing storage tank emission capture performance, and, if applicable, the selected strategies.

XVII.C.2.b.(ii) STEM must include a certification by the owner or operator that the selected STEM strategy or strategies are designed to meet the requirements of XVII.C.2.a. minimize emissions from storage tanks and

associated equipment components at the facility or facilities, including thief hatches and pressure relief devices.

XVII.C.3. Monitoring: The monitoring strategy of each STEM plan must include monitoring in accordance with Approved Instrument Based Monitoring Methods, as specified in Section XVII.F.5.

XVII.C.3.a.

In addition

to any applicable Approved Instrument Based Monitoring Methods, audio, visual, olfactory ("AVO") inspection of the storage tank and any associated equipment (i.e. separator, air pollution control equipment, or other pressure reducing equipment), must be completed as often as liquids are loaded out from the storage tank. However, AVO inspection is required no more frequently than every seven (7) days or less frequently than every thirty (30) days. AVO monitoring is not required for components and tanks that are unsafe to monitor. AVO inspection must include, at a minimum:

XVII.C.3.a.(i) Visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are enclosed and properly sealed;

XVII.C.3.a.(ii) Visual inspection or monitoring of the air pollution control equipment to ensure that it is operating, including that the pilot light is lit on combustion devices used as air pollution control equipment;

XVII.C.3.a.(iii) If a flare or other combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light, to ensure they are functioning properly;

XVII.C.3.a.(iv) Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the storage tank to the air pollution control equipment are open; and

XVII.C.3.a.(v) If a flare or other combustion device is used, inspection of the device for the presence of absence of smoke. If smoke is observed, either the equipment will be immediately shut-in to investigate that potential cause for smoke and perform repairs, as necessary, or Method 22 shall be conducted to determine whether visible emissions are present for a period of at least one (1) minute in fifteen (15) minutes.

XVII.C.4. Recordkeeping and Reporting: The owner or operator of each storage tank subject to XII.D. or XVII.C. must maintain records of STEM as applicable, including the plan, any updates, and the certification, and submit them to the Division by the applicable compliance date specified in section XVII.C.1.b. to be made available to the Division upon request. In addition, for a period of five years, the owner or operator

must maintain records of any required monitoring and make them available to the Division upon request, including:

- XVII.C.4.a. The AIRS ID for the storage tank.
- XVII.C.4.b. The date and duration of any period where the thief hatch, pressure relief device, or other access point are found to be venting hydrocarbon emissions.
- XVII.C.4.c. The date and duration of any period where the air pollution control equipment is not operating.
- XVII.C.4.d. Where a flare or other combustion device is being used, the date and result of any Method 22 test.
- XVII.C.4.e. The timing of and efforts made to eliminate venting, restore operation of air pollution control equipment, and mitigate visible emissions.

XVII.D. (State Only) Emission reductions from glycol natural gas dehydrators

- XVII.D.1. Beginning May 1, 2008, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, drip station or gas-processing plant subject to control requirements pursuant to Section XVII.D.2., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent through the use of a condenser or air pollution control equipment.
- XVII.D.2. The control requirement in Section XVII.D.1. shall apply where:
 - XVII.D.2.a. Actual uncontrolled emissions of volatile organic compounds from the glycol natural gas dehydrator are equal to or greater than two tons per year; and
 - XVII.D.2.b. The sum of actual uncontrolled emissions of volatile organic compounds from any single glycol natural gas dehydrator or grouping of glycol natural gas dehydrators at a single stationary source is equal to or greater than 15 tons per year. To determine if a grouping of dehydrators meets or exceeds the 15 tons per year threshold, sum the total actual uncontrolled emissions of volatile organic compounds from all individual dehydrators at the stationary source, including those with emissions less than two tons per year.
- XVII.D.3. Beginning May 1, 2015, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, and drip station or gas-processing plant subject to control requirements pursuant to Section XVII.D.4., shall reduce

uncontrolled actual emissions of hydrocarbons by at least 95 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons.

XVII.D.4. The control requirement in Section XVII.D.3. shall apply where:

XVII.D.4.a. Actual uncontrolled emissions of volatile organic compounds from a single new glycol natural gas dehydrator are equal to or greater than two tons per year; or

XVII.D.4.b. Actual uncontrolled emissions of volatile organic compounds from a single existing glycol natural gas dehydrator are equal to or greater than six (6) tons per year, or two (2) tons per year if the glycol natural gas dehydrator is located within 1,320 feet of a building unit or designated outside activity area.

XVII.D.4.c. For purposes of Section XVII.D.4.:

XVII.D.4.c.(i) Building Unit shall mean a residential building unit, and every five thousand (5,000) square feet of building floor area in commercial facilities or every fifteen thousand (15,000) square feet of building floor area in warehouses that are operating and normally occupied during working hours.

XVII.D.4.c.(ii) A designated outside activity area shall mean an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of public assembly owned or operated by a local government, which the local government seeks to have established as a Designated Outside Activity Area; or an outdoor venue or recreation area where ingress to or egress from could be impeded in the event of an emergency condition at an oil and gas location less than three hundred and fifty (350) feet from the venue due to the configuration of the venue and the number of persons known or expected to simultaneously occupy the venue on a regular basis.

XVII.E. Control of emissions from new, modified, existing, and relocated natural gas fired reciprocating internal combustion engines.

XVII.E.1. (State Only) The requirements of this Section XVII.E. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.2. (State Only) New, Modified and Relocated Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.2.a. Except as provided in Section XVII.E.2.b. below, the owner or operator on any natural gas fired reciprocating internal combustion engine that is either constructed or relocated to the state of Colorado from another state, on or after the date listed in the table below shall operate and maintain each engine according to the manufacturer's written instructions or procedures to the extent practicable and consistent with technological limitations and good engineering and maintenance practices over the entire life of the engine so that it achieves the emission standards required in Section XVII.E.2.b. Table 1 below.

XVII.E.2.b. Actual emissions from natural gas fired reciprocating internal combustion engines shall not exceed the emission performance standards in Table 1 below as expressed in units of grams per horsepower-hour (G/hp-hr)

TABLE 1				
Maximum Engine Hp	Construction or Relocation Date	Emission Standards in G/hp-hr		
		NOx	CO	VOC
< 100 Hp	Any	NA	NA	NA
≥100 Hp	On or after January 1, 2008	2.0	4.0	1.0
and < 500 Hp	On or after January 1, 2011	1.0	2.0	0.7
≥500 Hp	On or after July 1, 2007	2.0	4.0	1.0
	On or after July 1, 2010	1.0	2.0	0.7

XVII.E.3. Existing Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.3.a. (Regional Haze SIP) Rich Burn Reciprocating Internal Combustion Engines

XVII.E.3.a.(i) Except as provided in Sections XVII.3.1.(i)(b) and (c) and XVII.E.3.a.(ii), all rich burn reciprocating internal combustion engines with a manufacturer's name plate design rate greater than 500 horsepower, constructed or modified before February 1, 2009 shall install and operate both a non-selective catalytic reduction system and an air fuel controller by July 1, 2010. A rich burn reciprocating internal

combustion engine is one with a normal exhaust oxygen concentration of less than 2% by volume.

XVII.E.3.a.(i)(a) All control equipment required by this Section XVII.E.3.a. shall be operated and maintained pursuant to manufacturer specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file.

XVII.E.3.a.(i)(b) Internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63, a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard under 40 CFR Part 60 are not subject to this Section XVII.E.3.a.

XVII.E.3.a.(i)(c) The requirements of this Section XVII.E.3.a. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.3.a.(ii) Any rich burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than \$ 5,000 per ton of combined volatile organic compound and nitrogen oxides emission reductions (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.a. Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

XVII.E.3.b. (State Only) Lean Burn Reciprocating Internal Combustion Engines

XVII.E.3.b.(i) Except as provided in Section XVII.E.3.b.(ii), all lean burn reciprocating internal combustion engines with a manufacturer's nameplate design rate greater than 500 horsepower shall install and operate an oxidation catalyst by July 1, 2010. A lean burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of 2% by volume, or greater.

XVII.E.3.b.(ii) Any lean burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than \$ 5,000 per ton of volatile organic compound emission reduction (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.b.(i). Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

XVII.F. (State Only) Leak detection and repair program for well production facilities, storage tanks, and compressor stations

XVII.F.1. Beginning January 1, 2015, owners and operators of well production facilities and compressor stations will identify and repair leaks from components at these facilities in accordance with the requirements of this Section XVII.F. The following shall apply in lieu of any directed inspection and maintenance program requirements established pursuant to Regulation Number 3, Part B, Section III.D.2.

XVII.F.2. Owners and operators of well production facilities or natural gas compressor stations that monitor components as part of this Section XVII.F. may opt to estimate emissions from components for the purpose of evaluating the applicability of component fugitive emissions to Regulation Number 3 by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017).

XVII.F.3. Owners and operators of well production facilities or natural gas compressor stations shall utilize the Approved Instrument Based Monitoring Method and AVO program as outlined in Section XVII.F. AVO monitoring is not required of components and tanks that are unsafe to monitor or inaccessible to monitor, pursuant to XVII.F.5.g.

XVII.F.4. Inspection schedules for natural gas compressor stations: Beginning January 1, 2015, owners and operators of natural gas compressor stations shall inspect components for leaks using an Approved Instrument Based Monitoring Method, in accordance with the following Table 2, except for components subject to XVII.F.5.g. For purposes of this Section XVII.F.4., fugitive emissions shall be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), or other Division approved method.

Table 2	
Fugitive VOC Emissions (tpy) VOC Emissions – PTE (tpy)	Inspection Frequency
>0 and $\leq$ 12	Annually <u>with monthly AVO</u>
> 12 and $\leq$ 50	Quarterly <u>with monthly AVO</u>
> 50	Monthly

XVII.F.5. Requirements for well production facilities and/or storage tanks

XVII.F.5.a. Beginning August 1, 2014, all new well production facilities shall have a documented pressure test performed on all equipment and piping prior to start up. Documentation of this 90 day testing and monitoring shall be provided in the first annual report to the Division, as required by Section XVII.F.9.

XVII.F.5.b. Beginning January 1, 2015, within 90 days of startup of all new well production facilities and/or storage tanks, owners and/or operators shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method. Such action shall qualify as an inspection pursuant to the inspection frequency schedule in Table 3.

XVII.F.5.c. ~~Consistent with the provisions of XVII.F.5.f.~~ Beginning January 1, 2015, owners and operators of existing well production facilities and/or storage tanks shall identify and repair leaks using an Approved Instrument Based Monitoring Method, in accordance with the implementation schedule in XVII.F.5.e. Inspection frequency shall be determined according to Table 3.

XVII.F.5.d. Consistent with the provisions of XVII.F.5.f., owners and operators of new well production facilities and/or storage tanks shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method beginning on January 1, 2015. Inspection frequency shall be determined according to Table 3.

XVII.F.5.e. The estimated uncontrolled actual emissions from storage tanks determine the frequency at which inspections must be performed. If no storage tanks are located at the well production facility or multi-well site, operators will rely on the potential to emit of VOC for all of the emissions sources, including emissions from components located at the facility. All components at a well production facility or storage tank must be inspected:

Table 3	
Threshold (per XVII.F.5.e.) VOC Emissions (tpy, uncontrolled actual for sites with tanks or PTE for sites without tanks)	Inspection Frequency
> 0 and ≤ 126	Annually with monthly AVO One time using Approved Instrument Based Monitoring Method and thereafter using monthly AVO
> 6 and ≤ 12	Annually with monthly AVO
> 12 and ≤ 50	Quarterly with monthly AVO
> 50	Monthly
Multi-well sites without storage tanks after April 15, 2014, that have a PTE > 20 tpy VOC	Monthly

XVII.F.5.f. Phase in of Approved Instrument Based Monitoring Methods: Owners and operators of existing well production facilities and/or storage tanks shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method, in accordance with the following schedule:

XVII.F.5.f.(i) Beginning January 1, 2015, facilities with uncontrolled actual VOC emissions greater than 50 tpy or multi well sites.

XVII.F.5.f.(ii) Beginning July 1, 2015, facilities with uncontrolled actual VOC emissions greater than 20 tpy but less than or equal to 50 tpy.

XVII.F.5.f.(iii) Beginning January 1, 2016, facilities with uncontrolled actual VOC emissions greater than 6 tpy but less than or equal to 20 tpy.

XVII.F.5.g.(iv) By July 1, 2016, facilities with uncontrolled actual VOC emissions less than or equal to 6 tpy.

XVII.F.5.g. If a component is difficult, unsafe, or inaccessible to monitor, the owner or operator shall not be required to monitor the component until it becomes feasible to do so.

XVII.F.5.g.(i) Difficult to monitor components are those that cannot be monitored without elevating the monitoring personnel more than two meters above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

XVII.F.5.g.(ii) Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

XVII.F.5.g.(iii) Inaccessible to monitor components are those that are buried, insulated in a manner that prevents access to the components by a monitor probe, or obstructed by equipment or piping that prevents access to the components by a monitor probe.

XVII.F.6 Leak detection requiring repair: Leaks shall be identified utilizing the methods listed in this Section XVII.F.6.a. through XVII.F.6.d. Only leaks detected pursuant to this Section XVII.F.6. shall require repair under Section XVII.F.

XVII.F.6.a. For Method 21 monitoring at existing facilities, a leak is any concentration of hydrocarbon above 2,000 parts per million (ppm), except for existing well production facilities where leak is defined as any concentration of hydrocarbon above 500 ppm.

XVII.F.6.b. For Method 21 monitoring at facilities constructed after May 1, 2014, a leak is any concentration of hydrocarbon above 500 ppm.

XVII.F.6.c. For infra-red camera and AVO monitoring, a leak is any detectable emissions not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

XVII.F.6.d. For other Division approved monitoring devices or methods, leak identification requiring repair will be established as set forth in the Division's approval.

XVII.F.7. Repair and remonitoring

XVII.F.7.a. First attempt to repair a leak shall be made no later than five (5) working days after discovery, unless parts are unavailable ~~or~~ the equipment requires shutdown to complete repair, ~~or other good cause exists~~. If parts are unavailable, they shall be ordered promptly and the repair shall be made within five (5) ~~fifteen (15)~~ working days of receipt of the parts. If shutdown is required, the leak shall be repaired during the next scheduled shutdown. ~~If delay is attributable to other good cause,~~

repairs shall be completed within fifteen (15) working days after the cause of delay ceases to exist.

XVII.F.7.b. Within fifteen (15) working days of completion of a repair, the leaks shall be remonitored to verify the repair was effective.

XVII.F.7.c. Leaks discovered pursuant to the leak detection methods of Section XVII.F. shall not be subject to enforcement by the Division unless the owner or operator fails to perform the required repairs in accordance with Section XVII.F.7.

XVII.F.7.d. For leaks identified using an Approved Instrument Based Monitoring Method, owners and operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section XVII.F.7. or conducting follow-up monitoring using Method 21 within five (5) working days of the leak detected. If the follow-up Method 21 monitoring shows that the leak concentration is less than or equal to 2,000 ppm hydrocarbon for existing facilities (other than existing well production facilities), or 500 ppm for new facilities or existing well production facilities, then the emission shall not be considered a leak for purposes of this Section.

XVII.F.8. Recordkeeping: The owner or operator of each facility subject to the inspection and maintenance requirements in this Section XVII.F. shall maintain the following for a period of five (5) ~~two (2)~~ years and make them available to the Division upon request.

XVII.F.8.a. Documentation of the pre-start-up pressure tests for new well production facilities;

XVII.F.8.b. The date and site information for each inspection;

XVII.F.8.c. A list of the leaking components and the monitoring method used to determine the presence of the leak;

XVII.F.8.d. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;

XVII.F.8.e. The date the leak was repaired;

XVII.F.8.f. The delayed repair list including the basis for placing leaks on the list;

XVII.F.8.g. The date the leak was remonitored to verify the effectiveness of the repair, and the results of the remonitoring; and

XVII.F.8.h. A list of identification numbers for components that are designated as unsafe or inaccessible to monitor, as described in Section XVII.F.5.g., an

explanation for each component stating why the component is so designated, and the plan for monitoring such component(s).

XVII.F.9. Reporting: The owner or operator of each facility subject to the inspection and maintenance requirements in Section XVII.F. shall submit a single annual report on or before April 30th of each year summarizing inspection and maintenance activities at all of their subject facilities during the previous calendar year. This report shall contain at a minimum the following information:

- XVII.F.9.a. The number of facilities inspected;
- XVII.F.9.b. The total number of inspections;
- XVII.F.9.c. The total number of leaks identified, broken out by component type;
- XVII.F.9.d. The total number of leaks repaired;
- XVII.F.9.e. The number of leaks on the delayed repair list as of December 31st; and
- XVII.F.9.f. Each report shall be accompanied by a self-certification form. The form shall contain a certification by a responsible official of the truth, accuracy, and completeness of such form, report, or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

XVII.G. (State Only) Control of emissions from well production facilities

XVII.G.1. Well Operation and Maintenance: On or after August 1, 2014, during normal operation gas coming off a separator produced from any newly constructed, hydraulically fractured, or recompleted oil and gas well must either be routed to a gas gathering line or controlled by air pollution control equipment that achieves an average hydrocarbon control efficiency of 95% from the date of first production. If a combustion device is used, it shall have a design destruction efficiency of at least 98% of hydrocarbons.

XVII.H. (State Only) Venting during downhole well maintenance and unloading events

XVII.H.1. Well Maintenance: Beginning May 1, 2014, hydrocarbon emissions from flowing wells must be captured or controlled during downhole well maintenance or servicing activities, unless venting is necessary for safety.

XVII.H.1.a. Operators shall use best management practices to minimize the need for well venting associated with downhole well maintenance and liquids unloading. During liquids unloading events, any means of creating differential pressure will first be used to attempt to unload the liquids from the well without venting. If these methods are not successful in unloading the liquids from the

well, the well may be vented to the atmosphere to create the necessary differential pressure to bring the liquids to the surface.

XVII.H.1.b. Venting will be minimized to the extent possible, using best management practices during the well maintenance and liquids unloading events in XVII.H.1.a. The owner and/or operator shall be present on-site during any planned well maintenance and liquids unloading event in XVII.H.1.a. and shall ensure that any venting to the atmosphere is limited to the maximum extent practicable.

XVII.H.1.c. Records of the best management practices employed under this Section XVII.H., and the cause, date, time, and duration of venting events under this Section XVII.H., will be kept and submitted annually made available to the Division upon request.

XVIII. (State Only) Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations

XVIII.A. Applicability

This section applies to pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations, natural gas compressor stations, and/or natural gas drip stations).

XVIII.B. Definitions

XVIII.B.1. "Affected Operations" shall mean pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations, natural gas compressor stations, and/or natural gas drip stations).

XVIII.B.2. "Enhanced Maintenance" is specific to high-bleed devices and shall include but is not limited to cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; and eliminating unnecessary valve positioners.

XVIII.B.3. "High-Bleed Pneumatic Controller" shall mean a pneumatic controller that is designed to have a constant bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.

XVIII.B.4. "Low-Bleed Pneumatic controller" shall mean a pneumatic controller that is designed to have a constant bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.

XVIII.B.5. "Natural Gas Processing Plant" shall mean any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

XVIII.B.6. "No-bleed Pneumatic Controller" shall mean any pneumatic controller that is not using hydrocarbon gas as the valve's actuating gas.

XVIII.B.7. "Pneumatic Controller" shall mean an instrument that is actuated using natural gas pressure and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow and temperature.

XVIII.C. Emission Reduction Requirements

The owners and operators of affected operations shall reduce emissions of volatile organic compounds from pneumatic controllers associated with affected operations as follows:

XVIII.C.1. In the 8-Hour Ozone Control Area:

XVIII.C.1.a. All pneumatic controllers placed in service on or after February 1, 2009, shall emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.1.c.

XVIII.C.1.b. All high-bleed pneumatic controllers in service prior to February 1, 2009 shall be replaced or retrofit such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, by May 1, 2009, unless allowed pursuant to Section XVIII.C.1.c.

XVIII.C.1.c. All high-bleed pneumatic controllers that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.1.c.(i) For high-bleed pneumatic controllers in service prior to February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and /or process purposes by March 1, 2009. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.1.c.(ii) For high-bleed pneumatic controllers placed in service on or after February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and /or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.2. Statewide:

XVIII.C.2.a. All pneumatic controllers placed in service on or after May 1, 2014, shall:

XVIII.C.2.c.(i) Emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.; or

XVIII.C.2.c.(ii) Utilize no-bleed pneumatic controllers where on-site electrical grid power is being used and is technically and economically feasible.

XVIII.C.2.b. All ~~high-bleed~~ pneumatic controllers in service prior to May 1, 2014 with VOC emissions greater than a low-bleed pneumatic controller, shall be replaced or retrofitted by May 1, 2015, such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.

XVIII.C.2.c. All ~~high-bleed~~ controllers with VOC emissions greater than a low-bleed pneumatic controller that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.2.c.(i) ~~A For all high-bleed~~ pneumatic controllers in service prior to May 1, 2014, the owner/operator shall submit justification for ~~high-bleed all~~ pneumatic controllers with VOC emissions greater than a low-bleed pneumatic controller to remain in service due to safety and/or process purposes by March 1, 2015. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.2.c.(ii) For ~~high-bleed~~ pneumatic controllers placed in service on or after May 1, 2014, the owner/operator shall submit justification for ~~high-bleed all~~ pneumatic controllers with VOC emissions greater than a low-bleed pneumatic controller to be installed due to safety and/or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.D. Monitoring

This section applies only to high-bleed pneumatic controllers identified in Sections XVIII.C.1.c. and XVIII.C.2.c.

XVIII.D.1. In the 8-Hour Ozone Control Area

XVIII.D.1.a. Effective May 1, 2009, each high-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.1.b. Effective May 1, 2009, each high-bleed pneumatic controller shall be inspected on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2, and maintain the device according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.D.2. Statewide:

XVIII.D.2.a. Effective May 1, 2015, each ~~high-bleed pneumatic controller~~ with VOC emissions greater than a low-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique ~~high-bleed pneumatic controller~~ number that is assigned and maintained by the owner/operator.

XVIII.D.2.b. Effective May 1, 2015, each ~~high-bleed pneumatic controller~~ with VOC emissions greater than a low-bleed pneumatic controller shall be inspected on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2, and maintain the device according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.E. Recordkeeping

This section applies only to ~~high-bleed pneumatic controllers~~ with VOC emissions greater than a low-bleed pneumatic controller identified in Sections XVIII.C.1.c. and XVIII.C.2.c.

XVIII.E.1. The owner or operator of affected operations shall maintain a log of the total number of ~~high-bleed pneumatic controllers~~ with VOC emissions greater than a low-bleed pneumatic controller and their associated controller numbers per facility, the total number of ~~high-bleed~~ such pneumatic controllers per company and the associated justification that ~~those high-bleed pneumatic controllers~~ must be used pursuant to Sections XVIII.C.1.c. and XVIII.C.2.c. The log shall be updated on a monthly basis.

XVIII.E.2. The owner or operator shall maintain a log of enhanced maintenance which shall include, at a minimum, inspection dates, the date of the maintenance activity, ~~high-bleed pneumatic controller~~ number, description of the maintenance performed, results and date of any corrective action taken, and the printed name and signature of the individual performing the maintenance. The log shall be updated on a monthly basis.

XVIII.E.3. Records of enhanced maintenance of pneumatic controllers shall be maintained for a minimum of five (5) ~~three~~ years and readily made available to the Division upon request.

XXXXX-1. The system shall be designed to provide a means of monitoring the system's performance and to provide a means of detecting and reporting any failure of the system's performance.

XXXXX-2. The system shall be designed to provide a means of monitoring the system's performance and to provide a means of detecting and reporting any failure of the system's performance.

XXXXX-3. The system shall be designed to provide a means of monitoring the system's performance and to provide a means of detecting and reporting any failure of the system's performance.

XXXXX-4. The system shall be designed to provide a means of monitoring the system's performance and to provide a means of detecting and reporting any failure of the system's performance.

XXXXX-5. The system shall be designed to provide a means of monitoring the system's performance and to provide a means of detecting and reporting any failure of the system's performance.

XXXXX-6. The system shall be designed to provide a means of monitoring the system's performance and to provide a means of detecting and reporting any failure of the system's performance.

XXXXX-7. The system shall be designed to provide a means of monitoring the system's performance and to provide a means of detecting and reporting any failure of the system's performance.

XXXXX-8. The system shall be designed to provide a means of monitoring the system's performance and to provide a means of detecting and reporting any failure of the system's performance.

FINAL
ECONOMIC IMPACT ANALYSIS
PER § 25-7-110.5(4), C.R.S.

For Conservation Groups' Alternate Proposal modifying proposed revisions to
Colorado Air Quality Control Commission
Regulation Number 7 (5 CCR 1001-9)

I. INTRODUCTION

This economic analysis addresses the impact of the Conservation Groups' alternate proposal on the Division-proposed revisions to Regulation 7. The alternate proposal includes the following changes covered in this analysis:¹

1. Leak detection requirements for compressors should be expanded in two ways:
 - a. The definition of "Natural Gas Compressor Station" in Rule XVII.A.10 should be expanded so that it is not limited to those compressors upstream of processing facilities.
 - b. The inspection frequencies for compressor stations in Rule XVII.F should be calculated based on total VOC emissions (potential to emit), similar to the approach for well production facilities, rather than based only on fugitive VOC emissions.
2. For well production facilities and tanks with uncontrolled actual emissions of less than 6 tpy, the leak detection schedule in Rule XVII.F should require an instrument-based inspection on an annual basis – not just a single time.
3. Under Rule XVIII.C, the requirement to retrofit existing high-bleed pneumatic controllers should be clarified to ensure that it requires retrofitting all pneumatics emitting VOCs at a rate higher than a low-bleed pneumatic. This would include retrofitting intermittent-bleed pneumatics.

¹ The alternate proposal includes several other proposed changes, such as shortening excessively long phase-in periods and requiring that records be kept for a longer time period. These proposed requirements are not separately analyzed in the discussion below because they are not expected to involve any material costs to companies. This is consistent with the approach taken by the Division in its initial economic analysis, which does not alter its analysis of a requirement's cost-effectiveness based on when the requirement takes effect, or how long records must be retained, for example.

The discussion below uses the relevant sections from the Division's initial economic analysis, with modifications reflecting the limited changes proposed by the Conservation Groups.

II. COST/BENEFIT ANALYSIS:

A. Leak Detection and Repair Requirements for Compressor Stations and Well Production Facilities

AQCC Regulation Number 7 requires owners and operators of gas processing plants in Colorado to implement leak detection and repair programs to identify and repair fugitive emission leaks from components at these facilities. Under this requirement, owners and operators must conduct periodic inspections using EPA Reference Method 21² and repair leaks within a prescribed time frame.

Although component leaks at compressor stations and well production facilities in Colorado are also a significant source of VOC and methane emissions, Regulation No. 7 does not currently include leak detection and repair requirements for these facilities.³ To address these emissions, the Division is proposing regulatory changes that would establish leak detection and repair requirements for compressor stations and well production facilities. Pursuant to this proposal, owners and operators of compressor stations and well production facilities will be required to conduct periodic leak inspections, and repair identified leaks. As specified, required inspections may be done either in accordance with Method 21 or utilizing an IR camera. The proposed language also allows the Division to approve other inspection methods as new leak detection technologies are demonstrated to be effective.

The Division's Proposal would establish a tiered system to determine inspection frequency. For well production facilities, the tiering is based on the uncontrolled actual emissions from the largest storage tank at the facility.⁴ This approach creates a Method 21/IR camera monitoring schedule that is consistent with the monitoring schedule proposed as part of the STEM emission capture requirements. The Conservation Groups would use the same approach, but require that facilities with emissions under 6 tpy conduct annual instrument-based inspections (instead of just a one-time inspection as proposed by the Division). For compressor stations, the Division proposes tiers based on the station's fugitive emissions. The Conservation Groups tiering is based instead on the facility's potential to emit (PTE) VOCs.

² While Method 21 sets performance standards for inspection equipment rather than specifying technology, typically Method 21 inspections utilize photo ionization detectors (PIDs) to assess leak levels.

³ Although leak detection is not currently required at most of these facilities, some operators currently conduct voluntary leak detection and repair programs. Additionally, the Division has issued a limited number of permits that include some leak detection requirements. For the purposes of this analysis, however, the Division assumes that there is no leak detection occurring at well production facilities and compressor stations. Accordingly the actual additional costs that operators may incur may be less than the costs calculated in this analysis.

⁴ Because there may be instances where facilities do not have storage tanks, the proposal also provides that for tank-less facilities, the inspection schedule will be based on the facility's potential to emit (PTE) VOC.

For compressor stations and well production facilities, the frequencies proposed by the Conservation Groups are described as follows in Tables 1-2:

Table 1: Conservation Groups' Proposed Tiering for Leak Inspections at Compressor Stations	
PTE VOCs	Inspection Frequency
≤ 12 tpy	Annually, with monthly AVO
>12 tpy to ≤ 50 tpy	Quarterly, with monthly AVO
> 50 tpy	Monthly

Table 2: Conservation Groups' Proposed Tiering for Leak Inspections at Well Production Facilities	
Tank Uncontrolled Actual VOC Emissions or PTE	Inspection Frequency
≤ 12 tpy	Annually (and monthly AVO)
>12 tpy to ≤ 50 tpy	Quarterly (and monthly AVO)
> 50 tpy	Monthly

1. Well production facilities

To evaluate the cost-effectiveness of the alternate proposal with regard to well production facilities, the Conservation Groups followed the approach used by the Division in its initial economic analysis. The Division utilized a multi-step process to calculate the estimated costs and benefits associated with the proposed leak detection and repair requirements. First, the Division calculated an hourly inspection rate based on the total annual cost for each inspector divided by an assumed 1,880 annual work hours.⁵ To calculate the total annual cost for each inspector, the Division included salary and fringe benefits for each inspector, annualized equipment and vehicle costs, and add-ons to account for supervision, overhead, travel, record keeping, and reporting. Based on the assumptions set forth in the Division's EIA Table 20 (reproduced below), the total annual cost for each inspector will be \$186,129, which equates to an hourly inspection rate of \$99.

Leak Detection and Repair (LDAR) Inspector – Annualized Cost Analysis (Division EIA Table 20)			
Item	Capital Costs (one time)	Annual Costs	Annualized Total Costs
FLIR Camera	\$122,000		
Photo Ionization Detector	\$5,000		
Vehicle (4x4 Truck)	\$22,000		
Inspection Staff		\$75,000	
Supervision (@ 20%)		\$15,000	
Overhead (@10%)		\$7,500	
Travel (@15%)		\$11,250	

⁵ This assumes a 40 hour work week with ten holidays, two weeks of vacation, and one week of sick leave.

Recordkeeping (@10%)		\$7,500	
Reporting (@10%)		\$7,500	
Fringe (@30%)		\$22,500	
Subtotal Costs	\$149,000	\$146,250	
Annualized Costs*	\$39,879	\$146,250	\$186,129
*over 5 years at 6% ROR	Annualized Hourly Rate		\$99

Second, the Division calculated the average amount of time that it would take to conduct a Method 21 inspection at well production facilities based on the number of components to be inspected and assuming that a component could be inspected every 30 seconds. The proposed rule also allows owners and operators to use IR cameras either as the sole inspection tool, or as a screening tool to identify potential leaking components followed by a Method 21 inspection. An IR camera inspection or IR Camera/Method 21 hybrid inspection can be conducted more quickly than a Method 21 inspection of each component. While the Division does not currently have actual data regarding how much faster an inspection could be completed using an IR camera, for the purpose of its analysis the Division assumed that an IR camera based inspection would take 50% of the time required for a Method 21 inspection. Discussions with multiple private contractors that perform these inspections at well production and oil and gas processing facilities indicates that, on average, the value of 30 seconds per component for camera-based inspections errs on the side of over-estimation of time. One contractor with extensive experience with camera-based inspections stated that inspections can be conducted for 300 to 400 components per hour, when components are generally accessible.

For well production facilities, the Division has limited data on the number of components per facility. Based on this limitation, the Division did not attempt to calculate a separate inspection time for each of the proposed facility tiers, and instead used the overall average component count. Based on this overall average component count each Method 21 inspection will take 9.5 hours and each IR camera based inspection will take 4.75 hours.

Next, the Division calculated the projected inspection costs for well production facilities. To make this calculation the Division used industry reported emission data to determine the number of facilities that will be subject to annual, quarterly and monthly inspections to determine the total number of inspections for each tier, and multiplied these inspections by the calculated inspection time and projected hourly inspection rate. The calculated inspection costs for well production facilities do not include the cost to repair leaking components or re-monitor these components post-repair to verify that the repair was effective. Conversely, the calculated costs also do not account for the cost savings from capturing additional product as a result of repairs. For the purposes of its initial cost analysis the Division assumes that the cost savings from additional product capture will be equal to or greater than the cost of repair and re-inspection. The Division's estimated annual inspection costs for well production facilities are set forth in its EIA Table 23.⁶

⁶ The Division's proposal also requires monthly AVO inspections at facilities. Based on information provided during the stakeholder process, the Division reports that AVO inspections are part of current standard operational practice. Accordingly, the regulatory provisions should not result in additional costs.

Taking the same approach, the Conservation Groups' estimated annual inspection costs for well production facilities are set forth in Table 3.

Table 3: Well Production Facility Leak Inspection Costs Using IR Camera/Method 21 Hybrid

Uncontrolled Tank Battery VOCs/PTE Tier [tpy]	Number of Facilities	Annual Inspection Frequency	Inspection Time Per Inspection [hours]	Total Inspection Time [hours]	Total Annual Inspection Cost
≤12	4,200	1	4.75	19,950	\$1,975,050
> 12 to ≤ 50	2,916	4	4.75	55,404.0	\$5,484,996
> 50	964	12	4.75	54,498.0	\$5,439,852
Total:	8,080			129,852	\$12,899,898

Finally, the Division calculated the cost effectiveness of the proposed leak detection and repair requirements based on the costs identified above and the projected emission reductions. To determine emission reductions the Division first calculated pre-inspection program VOC and methane emissions based on the reported component counts, standard emission factors for these components, and the average fraction of VOC and non-VOC emissions (methane/ethane). Based on EPA reported information, the Division calculated a 40% reduction for annual inspections, a 60% reduction for quarterly inspections, and an 80% reduction for monthly inspections. The Division estimated total emissions reductions at well production facilities from its proposal would be 14,153 tpy VOC and 22,461 tpy methane/ethane. This resulted in a Division estimate that its proposal would cost \$818/ton VOC controlled, and \$516/ton methane/ethane controlled, at well production facilities. These were calculated in Tables 26-27 of the Division's EIA.

The Conservation Groups have used a similar approach. The total emissions reductions and cost-effectiveness at well production facilities from the alternate proposal are set forth in Tables 4-5. Under the alternate proposal, the cost effectiveness of conducting ongoing instrument based inspections at well production facilities is estimated to be \$668/ton VOC and \$421/ton methane/ethane. Thus, the Conservation Groups' alternate proposal for well production facilities is more cost-effective than the Division proposal.

Table 4: Well Production Facility Leak Inspection Emission Reductions

Uncontrolled Tank Battery VOCs/PTE Tier [tpy]	Number of Facilities	LDAR Program Reduction %	Fugitive VOC Emissions for each Tank Battery [tpy]	Total VOC Reduction [tpy]	Fugitive Methane-Ethane Emissions for each Tank Battery [tpy]	Total Methane-Ethane Reduction [tpy]
≤ 12	4,200	40%	4.6	7,728	7.3	12,264
> 12 to ≤ 50	2,916	60%	4.6	8,048.2	7.3	12,772.1
> 50	964	80%	4.6	3,547.5	7.3	5,629.8
Total:	8,080			19,323.7		30,665.9

Table 5: Well Production Facility Leak Cost-Effectiveness Using IR Camera/Method 21

Uncont. Tank Battery VOCs/PTE Tier [tpy]	Number of Tanks	Total Annual Inspection Cost	LDAR Program Reduction %	Total VOC Reduction [tpy]	VOC Control Cost [\$/ton]	Total Methane-Ethane Reduction [tpy]	Methane-Ethane Control Cost [\$/ton]
≤ 12	4,200	\$1,975,050	40%	7,728	\$256	12,264	\$161
> 12 to ≤ 50	2,919	\$5,484,996	60%	8,048.2	\$682	12,772.1	\$429
> 50	964	\$5,439,852	80%	3,547.5	\$1533	5,629.8	\$966
Total:	8,080	\$12,899,898		19,323	\$668	30,665.9	\$421

Finally, it should be noted that the Division's methodology for calculating the cost-effectiveness of LDAR at well production facilities is conservative in several respects. An analysis by the Clean Air Task Force of data from actual inspections found that costs are lower than those estimated by the Division. Testimony of David McCabe at 7-8.

2. Compressor stations

The Division's analysis of cost-effectiveness for compressor stations was similar to its analysis for well production facilities. It concluded that VOCs would be controlled at a cost of \$667/ton, and methane/ethane controlled for \$321/ton. These estimates are summarized in Table 25 of the Division's initial EIA.

Division Proposal - Compressor Station Leak Inspection Cost Effectiveness using IR Camera/Method 21 (Division EIA Table 25)

Comp. Station Fugitive VOC Tier	Number of Comp Stations	Total Annual Inspection Cost	LDAR Program Reduction %	Total VOC Reduction [tpy]	VOC Control Cost [\$/ton]	Total Methane-Ethane Reduction	Methane-Ethane Control Cost [\$/ton]
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[tpy]						[tpy]	
≤ 12	147	\$154,262	40%	593.9	\$260	911.4	\$169
> 12 to ≤ 50	53	\$589,763	60%	521.5	\$1,131	1,408.7	\$419
> 50			80%				
	200	\$744,025		1,115.4	\$667	2,320.1	\$321

For compressor stations, the Conservation Groups do not have data that allows for a comparable calculation of the cost-effectiveness of their alternate proposal. Testimony of Maureen Barrett at 3-4. As a result, the Conservation Groups cannot provide numeric estimates of: (a) how many additional facilities would be affected if the LDAR provisions cover compressor stations downstream of processing plants; (b) how many compressor stations would fall into each inspection tier based on total VOCs (instead of fugitive VOCs); and (c) the potential to emit of each compressor station.

With regard to the estimated 200 compressor stations upstream of processing plants, the Conservation Groups expect that their alternate proposal will be cost-effective. For these compressors, the alternate proposal is expected to require more frequent inspections because total facility VOC emissions are typically much greater than the fugitive emissions counted by the Division Proposal. Barrett testimony at 2-3. While the increased inspections will result in greater costs, that expense will be offset by greater reductions of VOCs and methane/ethane at compressors than would result from the Division Proposal. An analysis by Clean Air Task Force estimates that quarterly instrument-based inspections of compressor stations controls VOC emissions at a cost of \$800/metric ton, and the cost for monthly inspections is under \$3,500/metric ton. See McCabe testimony at 8. The control costs for methane are only about \$10/metric ton with quarterly inspections, and just over \$50/metric ton for monthly inspections. Id. at 4.

With regard to compressor stations downstream of processing plants, the cost of controlling methane/ethane reductions is likely to be even lower than for their upstream counterparts. The CATF figures indicate that methane control costs at transmission compressor stations are somewhat lower than those for gathering stations. McCabe testimony at 8-9.⁷

The cost per ton of VOC reductions for transmission compressor stations, however, likely would be greater than for compressors upstream of processing plants. Limited data is available, but the Title V permits for two such compressor stations, Kerr McGee's Fort Lupton station and DCP Midstream's Enterprise station, include limits for VOC fugitive emissions that allow for a conservative estimate of cost-effectiveness. The Kerr-McGee permit has a limit of 30.8 tpy fugitive VOCs, Supp. Testimony of Maureen Barrett at 2, and the DCP permit has a limit of 18.22 tpy fugitive VOCs. The Conservation Groups' alternate proposal would subject these two facilities to monthly instrument-based inspections. Assuming that such inspections reduce

⁷ If the value of gas conserved by LDAR programs is not considered in the analysis of abatement costs for transmission compressor stations (because the facility owners may not own the gas), the methane abatement cost for those facilities is slightly higher than for gathering compressor stations, but still very reasonable (under \$3/ metric ton CO₂e). McCabe testimony at 9 n. 5.

100%	147	\$134,345	60%	2978	2380	911.4	2189
> 15 to ≤ 20	37	\$399,563	60%	2978	\$1,131	408.7	2419
> 20			80%				
300		\$144,038	1,112.4	2967	2350.1		2321

For comparison between the Conservation Group's data and those for a comparable calculation of the cost-effectiveness of their abatement program. Testimony of Matthew Hansen at 3-4. As a result, the Conservation Group cannot provide a meaningful estimate of (a) how many additional facilities would be affected if the LBA program were expanded to cover compressor stations downstream of processing plants; (b) how many compressor stations would fall into each inspection tier based on total VOCs (upstream of injection VOCs); and (c) the potential to emit of each compressor station.

With regard to the estimated 100 compressor stations grouping of processing plants, the Conservation Group expects that their abatement program will be cost-effective. For these compressors, the abatement program is expected to require more frequent inspections because total facility VOC emissions are typically much greater than the fugitive emissions counted by the Division Program. Hansen testimony at 3-3. While the increased inspections will result in greater costs, that expense will be offset by greater reductions of VOCs and methane/gasoline at compressors that would result from the Division Program. An analysis by Clean Air Task Force estimates that quarterly instrument-based inspections of compressor stations could reduce emissions at a cost of \$300,000 per ton and the cost for monthly inspections is under \$1,500,000 per ton. See Hansen testimony at 3. The control costs for methane are only about \$100,000 per ton with quarterly inspections, and just over \$300,000 per ton for monthly inspections. Hansen testimony at 3-4.

With regard to compressor stations downstream of processing plants, the cost of controlling methane/gasoline reductions is likely to be even lower than for their upstream counterparts. The CATF figures indicate that methane control costs at transmission compressor stations are somewhat lower than those for gathering stations. Hansen testimony at 3-5.

The cost per ton of VOC reductions for transmission compressor stations, however, likely would be greater than for compressor stations upstream of processing plants. Limited data is available, but the CATF permits for two such compressor stations, New Mexico's Fort Union station and DCP Midstream's Enterprise station, include limits for VOC fugitive emissions that allow for a conservative estimate of cost-effectiveness. The Fort Union permit has a limit of 10.5 gpy fugitive VOCs. See Testimony of Matthew Hansen at 3. And the DCP permit has a limit of 14.35 gpy fugitive VOCs. The Conservation Group's abatement program would subject these two facilities to monthly instrument-based inspections. Assuming that such inspections reduce

¹¹ The value of the abatement by LBA program is not included in the analysis of abatement costs for transmission compressor stations because the CATF permit was adopted in 2011, the abatement program was not in place until 2012, and the abatement program was not in place until 2013. The abatement program was not in place until 2013, and the abatement program was not in place until 2013.

WPX REB EX A

BEFORE THE COLORADO AIR QUALITY CONTROL COMMISSION
COLORADO DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

WPX ENERGY ROCKY MOUNTAIN, LLC'S AND WPX ENERGY PRODUCTION, LLC'S PROPOSED REGULATION TEXT – WPX REB EX A

IN THE MATTER OF OIL & GAS RULEMAKING EFFORTS REGARDING PROPOSED
REVISIONS TO:

REGULATION NUMBER 3, PARTS A, B, AND C;

REGULATION NUMBER 6, PART A;

REGULATION NUMBER 7

WPX ENERGY ROCKY MOUNTAIN, LLC and WPX ENERGY PRODUCTION, LLC (collectively “WPX”) respectfully submit to the Colorado Air Quality Control Commission (“Commission”) WPX’s final proposed regulation text to accompany WPX’s alternate proposal¹ pursuant to Procedural Rule § V.C.3.c.

Based on the revised language of the Proposed Regulation Text circulated by the Division on January 24, 2014, please see the attached revised alternate proposal by WPX indicated by the redlined attachment. See attached WPX ALT EX D REVISED. For clarity, WPX has only included here the sections for which it proposes changes, and has indicated such changes in the attached redline.

¹ Note that WPX does not believe that the minor changes it proposed on January 6, 2014, rise to the level of an alternate proposal. However, out of an abundance of caution, WPX filed its proposed revisions to the Division rules as an alternate proposal with the documents described in 5 CCR 1001-1 (“Procedural Rules”) Section V.C.3.a through k.

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 7

CONTROL OF OZONE PRECURSORS AND CONTROL OF
HYDROCARBONS VIA OIL AND GAS EMISSIONS

XVII.C.1.e.(ii)
(new section)

Unsafe to monitor means it cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring, which includes weather conditions preventing access to the site, or that endanger monitoring personnel or equipment, or prevent use of Approved Instrument Based Monitoring Methods (such as reflection due to precipitation).

XVII.F.5.c.

Owners or operators of well production facilities constructed before January 1, 2015, must identify leaks from components using an approved instrument based monitoring method within ninety (90) days of the Phase-In Schedule in Table 4, within thirty (30) days for > 50 tons per year, or by July 1, 2016, for > 0 and < 6 tons per year tanks. Thereafter, approved instrument based monitoring method and AVO inspections must be conducted in accordance with the Inspection Frequency in Table 4.4 or when a reduced LDAR demonstration is made, the frequency may be determined by Alternative Table 4A pursuant to Section XVII.F.5.d.

XVII.F.5.ed.

The largest estimated uncontrolled actual emissions from a single storage ~~tanks~~ ~~determine~~ ~~tank batteries~~ determines the frequency at which inspections must be performed. If no storage tanks storing oil or condensate are located at the well production facility or multi-well site, owners or operators must rely on the potential to emit of VOC for all of the emissions sources, including emissions from components located at the well production facility in accordance with Table 4 of Alternative Table 4A.

Table 4 – Well Production Facility Component Inspections		
Threshold (per XVII.F.5.d.) VOC Emissions (tpy)	Inspection Frequency	Phase-In Schedule
> 0 and < 6	One time using approved Instrument based monitoring method and thereafter using monthly AVO	July 1, 2016
> 6 and < 12	Annually with monthly AVO	January 1, 2016
> 12 and < 50	Quarterly with monthly AVO	July 1, 2015
> 50	Monthly	January 1, 2015
Well production facilities or multi-well sites without storage tanks storing oil or condensate that have a potential to emit > 20 tpy VOC	Monthly	January 1, 2015

WPX REB EX A
WPX ALT EX D REVISED

An alternative inspection frequency schedule pursuant to Alternative Table 4A may be implemented once a reduced LDAR demonstration is made. A reduced LDAR demonstration requires that an owner or operator identify fewer than either (1) the specified number of leaking components listed in “Demonstration of Reduced LDAR – Monitoring History” in Alternative Table 4A or (2) two percent of the total components for that facility during a single monitoring event, for at least two consecutive monitoring events.

Once the reduced LDAR demonstration is made pursuant to this Section, the alternative inspection frequency pursuant to Alternative Table 4A may remain in place until, during any monitoring event under the alternative inspection frequency, more leaks are identified than allowed under Alternative Table 4A’s “Demonstration of Reduced LDAR – Monitoring History.” Using the alternative inspection frequency identified in Alternative Table 4A, during any monitoring event, if more leaks are identified than listed in the “Demonstration of Reduced LDAR – Monitoring History,” then the original monitoring frequency identified in Table 4 shall become applicable until or if the operator can make another reduced LDAR demonstration for that facility.

<u>Alternative Table 4A</u>		
<u>Threshold (per XVII.F.5.e.) VOC Emissions (tpy, uncontrolled actual for sites with tanks or PTE for sites without tanks)</u>	<u>Demonstration of Reduced LDAR - Monitoring History</u>	<u>Alternative Inspection Frequency</u>
<u>> 0 and < 6</u>		<u>One time using Approved Instrument Based Monitoring Method and thereafter using monthly AVO</u>
<u>> 6 and < 12</u>		<u>Annually with monthly AVO</u>
<u>> 12 and < 50</u>	<u>5 or less component leaks (or 2% of total components) identified in each of two consecutive monitoring events.</u>	<u>Annually with monthly AVO</u>
<u>> 50</u>	<u>10 or less component leaks (or 2% of total components) identified in each of two consecutive monitoring events.</u>	<u>Quarterly with monthly AVO</u>
<u>Multi-well sites without storage tanks after April 15, 2014, that have a PTE > 20 tpy VOC</u>	<u>10 or less component leaks (or 2% of total components) identified in each of two consecutive monitoring events.</u>	<u>Quarterly with monthly AVO</u>

WPX REB EX A
WPX ALT EX D REVISED

- XVII.F.~~5-g-(ii)~~6.b. Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring, which includes weather conditions preventing access to the site, or that endanger monitoring personnel or equipment, or prevent use of Approved Instrument Based Monitoring Methods (such as reflection due to precipitation).
- XVII.F.~~6-7~~a. For EPA Method 21 monitoring at facilities constructed before May 1, 2014, a leak is any concentration of hydrocarbon above 2,000 parts per million (ppm), except for existing well production facilities where a leak is defined as any concentration of hydrocarbon above 500 ppm-after January 1, 2016.
- XVII.F.~~6-7~~b. For EPA Method 21 monitoring at facilities constructed on or after ~~May~~January 1, ~~2014, 2016.~~ a leak is any concentration of hydrocarbon above 500 ppm.

EXHIBIT 9.C

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 7

**CONTROL OF OZONE VIA OZONE PRECURSORS AND CONTROL OF
HYDROCARBONS VIA OIL AND GAS EMISSIONS**

(EMISSIONS OF VOLATILE ORGANIC COMPOUNDS AND NITROGEN OXIDES)

5 CCR 1001-9

>>>>>>>>

II. General Provisions

>>>>>>>>

II.B. Exemptions

Emissions of the organic compounds listed as having negligible photochemical reactivity in the common provisions definition of Negligibly Reactive Volatile Organic Compound are exempt from the provisions of this regulation.

(State Only) Notwithstanding the foregoing exemption, hydrocarbon emissions from oil and gas operations, including methane and ethane, are subject to this regulation as set forth in Sections XVII. and XVIII.

>>>>>>>>

XVII. (State Only, except Section XVII.E.3.a. which was submitted as part of the Regional Haze SIP) Statewide Controls for Oil and Gas Operations and Natural Gas-Fired Reciprocating Internal Combustion Engines

XVII.A. (State Only) Definitions

XVII.A.1 "Air Pollution Control Equipment," as used in this Section XVII, means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment and pollution prevention devices and processes intended to reduce uncontrolled actual emissions that comply with the requirements of Section XVII.B.2.e.

XVII.A.2. "Approved Instrument Based Monitoring Method," as used in this Section XVII. means an infra-red camera, Method 21, or other Division approved instrument based monitoring device or method. If an owner/operator elects to use a Division approved Continuous Emission Monitoring program, the Division may approve a streamlined inspection and reporting program for such operations. Any instrument based monitoring method approved by the Division under this definition must be at least as effective as Method 21 or an infra-red camera.

XVII.A.3. "Auto-Igniter" means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust volatile organic compound emissions.

XVII.A.4. "Building Unit" shall mean a residential building unit, and every five thousand (5,000) square feet of building floor area in commercial facilities or every fifteen thousand (15,000) square feet of building floor area in warehouses that are operating and normally occupied during working hours.

XVII.A.54. "Component" means each pump seal, compressor seal, flange, pressure relief device, connector, open ended line, and valve that contains or contacts a process stream with hydrocarbons. Process streams consisting of glycol, amine, produced water, or methanol are not components for purposes of this Section XVII.

XVII.A.65. "Connector" means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Jointed fittings welded completely around the circumference of the interface are not considered connectors.

XVII.A.76. "Date of First Production" means the date reported to the COGCC as the "first date of production."

XVII.A.8. "Designated Outside Activity Area" shall mean an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of public assembly owned or operated by a local government, which the local government seeks to have established as a Designated Outside Activity Area; or an outdoor venue or recreation area where ingress to or egress from could be impeded in the event of an emergency condition at an oil and gas location less than three hundred and fifty (350) feet from the venue due to the configuration of the venue and the number of persons known or expected to simultaneously occupy the venue on a regular basis.

XVII.A.97. "Glycol Natural Gas Dehydrator" means any device in which a liquid glycol (including ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.

XVII.A.10. "Major Gas Leak" shall mean any leak greater than 10,000 ppm hydrocarbon concentration above background as determined through an approved instrument based monitoring method.

XVII.A.118. "Multi-Well Site" means a common well pad from which multiple wells may be drilled to various bottomhole locations.

XVII.A.129. "Natural Gas Compressor Station" means a facility which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure and recompress natural gas prior to processing.

XVII.A.130. "Normal Operation" means all periods of operation, excluding malfunctions as defined in Section I.G. of the Common Provisions regulation. For storage tanks at well production facilities, normal operation includes but is not limited to liquid dumps from the separator.

XVII.A.141. "Stabilized" when used to refer to crude oil, condensate, intermediate hydrocarbon liquids, or produced water means that the vapor pressure of the liquid is sufficiently low to prevent the production of vapor phase upon transferring the liquid to an atmospheric pressure in a storage tank, and that any emissions that occur are limited to

those commonly referred to within the industry as working, breathing, and standing losses.

XVII.A.1~~52~~. “Storage Tank” means any fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. Storage vessel is as defined in 40 CFR Part 60, Subpart OOOO. Storage tanks may be located at a well production facility or other location.

XVII.A.1~~63~~. “Unsafe to Monitor” means a component is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of such monitoring.

XVII.A.1~~74~~. “Visible Emissions” means observations of smoke and/or hydrocarbon vapors for any period or periods of duration greater than or equal to one (1) minute in any fifteen (15) minute period during normal operation. Visible emissions do not include radiant energy ~~or water vapor~~.

XVII.A.1~~85~~. “Well Production Facility” means all equipment at a single stationary source directly associated with one or more oil wells or gas wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

XVII.B. (State Only) General Provisions

XVII.B.1. General requirements for prevention of emissions and good air pollution control practices for all oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.

XVII.B.1.a. All intermediate hydrocarbon liquids collection, storage, processing, and handling operations, regardless of size, shall be designed, operated, and maintained so as to minimize leakage of volatile organic compounds to the atmosphere to the extent reasonably practicable.

XVII.B.1.b. At all times, including periods of start-up and shutdown, the facility and air pollution control equipment shall be maintained and operated in a manner consistent with ~~good air pollution control~~ best management practices for minimizing emissions. Determination of whether or not acceptable operating and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

XVII.B.2. General requirements for air pollution control equipment, flares, and combustion devices used to comply with Section XVII.

XVII.B.2.a. All air pollution control equipment shall be operated and maintained pursuant to the manufacturing specifications or equivalent ~~to the extent practicable~~, and consistent with technological limitations and good best engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file. In addition, all such air pollution control equipment shall be adequately designed and sized to achieve the control efficiency rates and to handle reasonably foreseeable fluctuations in emissions of volatile organic compounds and hydrocarbons during normal operations.

Fluctuations in emissions that occur when the separator dumps into the tank are reasonably foreseeable.

XVII.B.2.b. If a flare or other combustion device is used to control emissions of hydrocarbons, it shall be enclosed, have no visible emissions during normal operations, and be designed so that an observer can, by means of visual observation from the outside of the enclosed flare or combustion device, or by other means approved by the Division, determine whether it is operating properly.

XVII.B.2.c. Any of the effective dates for installation of controls on storage tanks, dehydrators, and/or internal combustion engines may be extended at the Division's discretion for good cause shown.

XVII.B.2.d. Auto-igniters: All combustion devices used to control emissions of hydrocarbons shall be equipped with and operate an auto-igniter as follows:

XVII.B.2.d.(i) All combustion devices installed on or after May 1, 2014, will be equipped with an operational auto-igniter upon installation of the combustion device.

XVII.B.2.d.(ii) All combustion devices installed before May 1, 2014, will be equipped with an operational auto-igniter by or before May 1, 2016, or after the next combustion device planned shutdown, whichever comes first.

XVII.B.2.e. Alternative emissions control equipment shall qualify as air pollution control equipment, and may be used in lieu of, or in combination with, combustion devices and vapor recovery units to achieve the emission reductions required by this Section XVII, if the Division approves the equipment, device or process. As part of the approval process the Division, at its discretion, may specify a different control efficiency than the control efficiencies required by this Section XVII.

XVII.B.3. Oil refineries are not subject to Section XVII.

XVII.B.4. Glycol natural gas dehydrators and internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63, a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard ("NSPS") under 40 CFR Part 60 are not subject to this Section XVII.

XVII.C. (State Only) Emission reduction from storage tanks at oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.

XVII.C.1. Control requirements for storage tanks

XVII.C.1.a. Beginning May 1, 2008, owners or operators of all storage tanks storing condensate with uncontrolled actual emissions of volatile organic compounds equal to or greater than twenty (20) tons per year based on a rolling twelve-month total must operate air pollution control equipment that has an average control efficiency of at least 95% for VOCs.

XVII.C.1.b. Owners or operators of all storage tanks with uncontrolled actual emissions of volatile organic compounds, based on a rolling twelve-month total, equal to or greater than six (6) tons per year, based on a rolling twelve-month total or two (2) tons per year if the storage tanks is located within 1,320 feet of a building unit or designated outside activity area, must operate air pollution control equipment that achieves an average hydrocarbon control efficiency of no less than 95%. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons.

XVII.C.1.b.(i) A storage tank constructed on or after May 1, 2014, must be in compliance by the date that the storage tank commences operation.

XVII.C.1.b.(ii) A storage tank constructed before May 1, 2014, must be in compliance by May 1, 2015.

XVII.C.1.b.(iii) A storage tank not otherwise subject to Sections XVII.C.1.b.(i) or XVII.C.1.b.(ii), above, that increases uncontrolled actual emissions to six (6) tons VOC or more per year on a rolling twelve month basis after May 1, 2014, or two tons VOC or more per year if located within 1,320 feet of a building unit or designated outside activity area, must be in compliance within sixty days of discovery of the emissions increase.

XVII.C.1.c. Control requirements within 90 days of the date of first production.

XVII.C.1.c.(i) Beginning May 1, 2014, owners or operators of storage tanks at well production facilities shall collect and control emissions by routing emissions to operating air pollution control equipment during the first 90 calendar days after the date of first production. The air pollution control equipment shall achieve an average hydrocarbon control efficiency of 95%. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons. Except that this requirement does not apply to storage tanks that are projected to have emissions less than 1.5 tons of VOC during the first 90 days after the date of first production, or 0.5 tons of VOC emissions during the first 90 days after the date of first production if located 1,320 feet from a building unit or designated outdoor activity area.

XVII.C.1.c.(ii) The air pollution control equipment and any associated monitoring equipment required pursuant to Section XVII.C.1.c., above, may be removed at any time after the first 90 calendar days as long as the source can demonstrate that uncontrolled actual emissions from the storage tank are below the thresholds in Section XVII.C.1.b., above.

XVII.C.2. Capture requirements for storage tanks that are fitted with air pollution control equipment as required by Sections XII.D. or XVII.C.1.

XVII.C.2.a. Beginning on the applicable compliance date specified in Section XVII.C.1.b., owners and operators of storage tanks shall route all hydrocarbon emissions to air pollution control equipment, and shall operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation unless venting is reasonably required for maintenance, gauging, or safety of personnel and equipment.

XVII.C.2.b. Beginning on the applicable compliance date specified in section XVII.C.1.b., owners and operators of storage tanks shall develop, certify, and

implement a document Storage Tank Emission Management System (STEM) plan to identify appropriate strategies to minimize emissions from venting at thief hatches (or other access points to a storage tank) and pressure relief devices during normal operation. As part of STEM, owners and operators shall evaluate and employ appropriate control technologies, monitoring practices, operational practices, and/or other strategies designed to meet the requirements set forth in Section XVII.C.2.a., above, and will update the STEM plan as necessary to achieve or maintain compliance. Owners and operators are not required to develop and implement STEM for storage tanks containing only stabilized liquids. The minimum elements of STEM are listed below.

XVII.C.2.b.(i) STEM must include a monitoring strategy that incorporates the minimum monitoring frequency set forth in Section XVII.F.5.e., procedures for evaluating ongoing storage tank emission capture performance, and, if applicable, the selected strategies.

XVII.C.2.b.(ii) STEM must include a certification by the owner or operator that the selected STEM strategy or strategies are designed to minimize emissions from storage tanks and associated equipment components at the facility or facilities, including thief hatches and pressure relief devices.

XVII.C.3. Monitoring: The monitoring strategy of each STEM plan must include monitoring in accordance with Approved Instrument Based Monitoring Methods, as specified in Section XVII.F.5.

XVII.C.3.a. In addition to any applicable Approved Instrument Based Monitoring Methods, audio, visual, olfactory ("AVO") inspection of the storage tank and any associated equipment (i.e. separator, air pollution control equipment, or other pressure reducing equipment), must be completed as often as liquids are loaded out from the storage tank. However, AVO inspection is required no more frequently than every seven (7) days or less frequently than every thirty (30) days. AVO monitoring is not required for components and tanks that are unsafe to monitor. AVO inspection must include, at a minimum:

XVII.C.3.a.(i) Visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are enclosed and properly sealed;

XVII.C.3.a.(ii) Visual inspection or monitoring of the air pollution control equipment to ensure that it is operating, including that the pilot light is lit on combustion devices used as air pollution control equipment;

XVII.C.3.a.(iii) If a flare or other combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light, to ensure they are functioning properly;

XVII.C.3.a.(iv) Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the storage tank to the air pollution control equipment are open; and

XVII.C.3.a.(v) If a flare or other combustion device is used, inspection of the device for the presence ~~of or~~ absence of smoke ~~or vapors~~. If smoke ~~or vapors are~~ observed, either the equipment will be immediately shut-in to investigate that potential cause for smoke and perform repairs, as necessary, or Method 22 shall be conducted to determine whether visible

emissions are present for a period of at least one (1) minute in fifteen (15) minutes.

XVII.C.4. Recordkeeping: The owner or operator of each storage tank subject to XII.D. or XVII.C. must maintain records of STEM as applicable, including the plan, any updates, and the certification, to be made available to the Division upon request. In addition, for a period of two years, the owner or operator must maintain records of any required monitoring and make them available to the Division upon request, including:

XVII.C.4.a. The AIRS ID for the storage tank.

XVII.C.4.b. The date and duration of any period where the thief hatch, pressure relief device, or other access point are found to be venting hydrocarbon emissions.

XVII.C.4.c. The date and duration of any period where the air pollution control equipment is not operating.

XVII.C.4.d. Where a flare or other combustion device is being used, the date and result of any Method 22 test.

XVII.C.4.e. The timing of and efforts made to eliminate venting, restore operation of air pollution control equipment, and mitigate visible emissions.

XVII.D. (State Only) Emission reductions from glycol natural gas dehydrators

XVII.D.1. Beginning May 1, 2008, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, drip station or gas-processing plant subject to control requirements pursuant to Section XVII.D.2., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent through the use of a condenser or air pollution control equipment.

XVII.D.2. The control requirement in Section XVII.D.1. shall apply where:

XVII.D.2.a. Actual uncontrolled emissions of volatile organic compounds from the glycol natural gas dehydrator are equal to or greater than two tons per year; and

XVII.D.2.b. The sum of actual uncontrolled emissions of volatile organic compounds from any single glycol natural gas dehydrator or grouping of glycol natural gas dehydrators at a single stationary source is equal to or greater than 15 tons per year. To determine if a grouping of dehydrators meets or exceeds the 15 tons per year threshold, sum the total actual uncontrolled emissions of volatile organic compounds from all individual dehydrators at the stationary source, including those with emissions less than two tons per year.

XVII.D.3. Beginning May 1, 2015, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, and drip station or gas-processing plant subject to control requirements pursuant to Section XVII.D.4., shall reduce uncontrolled actual emissions of hydrocarbons by at least 95 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons.

XVII.D.4. The control requirement in Section XVII.D.3. shall apply where:

XVII.D.4.a. Actual uncontrolled emissions of volatile organic compounds from a single new glycol natural gas dehydrator are equal to or greater than two (2) tons per year; or

XVII.D.4.b. Actual uncontrolled emissions of volatile organic compounds from a single existing glycol natural gas dehydrator are equal to or greater than six (6) tons per year, or two (2) tons per year if the glycol natural gas dehydrator is located within 1,320 feet of a building unit or designated outside activity area.

~~XVII.D.4.c. For purposes of Section XVII.D.4.:~~

~~XVII.D.4.c.(i) Building Unit shall mean a residential building unit, and every five thousand (5,000) square feet of building floor area in commercial facilities or every fifteen thousand (15,000) square feet of building floor area in warehouses that are operating and normally occupied during working hours.~~

~~XVII.D.4.c.(ii) A designated outside activity area shall mean an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of public assembly owned or operated by a local government, which the local government seeks to have established as a Designated Outside Activity Area; or an outdoor venue or recreation area where ingress to or egress from could be impeded in the event of an emergency condition at an oil and gas location less than three hundred and fifty (350) feet from the venue due to the configuration of the venue and the number of persons known or expected to simultaneously occupy the venue on a regular basis.~~

XVII.E. Control of emissions from new, modified, existing, and relocated natural gas fired reciprocating internal combustion engines.

XVII.E.1. (State Only) The requirements of this Section XVII.E. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.2. (State Only) New, Modified and Relocated Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.2.a. Except as provided in Section XVII.E.2.b. below, the owner or operator on any natural gas fired reciprocating internal combustion engine that is either constructed in or relocated to the state of Colorado from another state, on or after the date listed in the table below shall operate and maintain each engine according to the manufacturer's written instructions or procedures to the extent practicable and consistent with technological limitations and good engineering and maintenance practices over the entire life of the engine so that it achieves the emission standards required in Section XVII.E.2.b. Table 1 below.

XVII.E.2.b. Actual emissions from natural gas fired reciprocating internal combustion engines shall not exceed the emission performance standards in Table 1 below as expressed in units of grams per horsepower-hour (G/hp-hr)

TABLE 1

Maximum Engine Hp	Construction or Relocation Date	Emission Standards is G/hp-hr		
		NOx	CO	VOC
< 100 Hp	Any	NA	NA	NA
≥100 Hp and < 500 Hp	On or after January 1, 2008	2.0	4.0	1.0
	On or after January 1, 2011	1.0	2.0	0.7
≥500 Hp	On or after July 1, 2007	2.0	4.0	1.0
	On or after July 1, 2010	1.0	2.0	0.7

XVII.E.3. Existing Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.3.a. (Regional Haze SIP) Rich Burn Reciprocating Internal Combustion Engines

XVII.E.3.a.(i) Except as provided in Sections XVII.3.1.(i)(b) and (c) and XVII.E.3.a.(ii), all rich burn reciprocating internal combustion engines with a manufacturer's name plate design rate greater than 500 horsepower, constructed or modified before February 1, 2009 shall install and operate both a non-selective catalytic reduction system and an air fuel controller by July 1, 2010. A rich burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of less than 2% by volume.

XVII.E.3.a.(i)(a) All control equipment required by this Section XVII.E.3.a. shall be operated and maintained pursuant to manufacturer specifications or equivalent to the extent practicable, and consistent with technological limitations and ~~best~~good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file.

XVII.E.3.a.(i)(b) Internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63, a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard under 40 CFR Part 60 are not subject to this Section XVII.E.3.a.

XVII.E.3.a.(i)(c) The requirements of this Section XVII.E.3.a. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.3.a.(ii) Any rich burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than \$ 5,000 per ton of combined volatile

organic compound and nitrogen oxides emission reductions (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.a. Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

XVII.E.3.b. (State Only) Lean Burn Reciprocating Internal Combustion Engines

XVII.E.3.b.(i) Except as provided in Section XVII.E.3.b.(ii), all lean burn reciprocating internal combustion engines with a manufacturer's nameplate design rate greater than 500 horsepower shall install and operate an oxidation catalyst by July 1, 2010. A lean burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of 2% by volume, or greater.

XVII.E.3.b.(ii) Any lean burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than \$ 5,000 per ton of volatile organic compound emission reduction (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.b.(i). Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

XVII.F. (State Only) Leak detection and repair program for well production facilities, storage tanks, and compressor stations

XVII.F.1. Beginning January 1, 2015, owners and operators of well production facilities and compressor stations will identify and repair leaks from components at these facilities in accordance with the requirements of this Section XVII.F. The following shall apply in lieu of any directed inspection and maintenance program requirements established pursuant to Regulation Number 3, Part B, Section III.D.2.

XVII.F.2. Owners and operators of well production facilities or natural gas compressor stations that monitor components as part of this Section XVII.F. may opt to estimate emissions from components for the purpose of evaluating the applicability of component fugitive emissions to Regulation Number 3 by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017).

XVII.F.3. Owners and operators of well production facilities or natural gas compressor stations shall utilize the Approved Instrument Based Monitoring Method and AVO program as outlined in Section XVII.F. AVO monitoring is not required of components and tanks that are unsafe to monitor or inaccessible to monitor, pursuant to XVII.F.5.g.

XVII.F.4. Inspection schedules for natural gas compressor stations: Beginning January 1, 2015, owners and operators of natural gas compressor stations shall inspect components for leaks using an Approved Instrument Based Monitoring Method, in accordance with the following Table 2, except for components subject to XVII.F.5.g. For purposes of this

Section XVII.F.4., fugitive emissions shall be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), of other Division approved method.

Table 2	
Fugitive VOC Emissions (tpy)	Inspection Frequency
>0 and $\leq$ 12	Annually
> 12 and $\leq$ 50	Quarterly
> 50	Monthly

XVII.F.5. Requirements for well production facilities and/or storage tanks

XVII.F.5.a. Beginning August 1, 2014, all new well production facilities shall have a documented pressure test performed on all equipment and piping prior to start up. Documentation of this 90 day testing and monitoring shall be provided in the first annual report to the Division, as required by Section XVII.F.9.

XVII.F.5.b. Beginning January 1, 2015, within 90 days of startup of all new well production facilities and/or storage tanks, owners and/or operators shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method. Such action shall qualify as an inspection pursuant to the inspection frequency schedule in Table 3.

XVII.F.5.c. Consistent with the provisions of XVII.F.5.f., owners and operators of existing well production facilities and/or storage tanks shall identify and repair leaks using an Approved Instrument Based Monitoring Method, in accordance with the implementation schedule in XVII.F.5.e. Inspection frequency shall be determined according to Table 3.

XVII.F.5.d. Consistent with the provisions of XVII.F.5.f., owners and operators of new well production facilities and/or storage tanks shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method beginning on January 1, 2015. Inspection frequency shall be determined according to Table 3.

XVII.F.5.e. The estimated uncontrolled actual emissions from storage tanks determine the frequency at which inspections must be performed. If no storage tanks are located at the well production facility or multi-well site, operators will rely on the potential to emit of VOC for all of the emissions sources, including emissions from components located at the facility. All components at a well production facility or storage tank must be inspected:

Table 3		
Threshold (per XVII.F.5.e.) VOC	Threshold within 1,320 feet of a building	Inspection Frequency

Emissions (tpy, uncontrolled actual for sites with tanks or PTE for sites without tanks)	<u>unit or designated outside activity area (per XVII.F.5.e.) VOC Emissions (tpy, uncontrolled actual for sites with tanks or PTE for sites without tanks)</u>	
> 0 and $\leq$ 6		One time using Approved Instrument Based Monitoring Method and thereafter using monthly AVO
> 6 and $\leq$ 12	<u>> 0 and < 6</u>	Annually with monthly AVO
> 12 and $\leq$ 50	<u>> 6 and < 12</u>	Quarterly with monthly AVO
> 50	<u>> 12</u>	Monthly
Multi-well sites without storage tanks after April 15, 2014, that have a PTE > 20 tpy VOC	<u>Multi-well sites without storage tanks after April 15, 2014, that have a PTE > 12 tpy VOC</u>	Monthly

XVII.F.5.f. Phase-in of Approved Instrument Based Monitoring Methods: Owners and operators of existing well production facilities and/or storage tanks shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method, in accordance with the following schedule:

XVII.F.5.f.(i) Beginning January 1, 2015, facilities with uncontrolled actual VOC emissions greater than 50 tpy or multi-well sites.

XVII.F.5.f.(ii) Beginning July 1, 2015, facilities with uncontrolled actual VOC emissions greater than 20 tpy but less than or equal to 50 tpy.

XVII.F.5.f.(iii) Beginning January 1, 2016, facilities with uncontrolled actual VOC emissions greater than 6 tpy but less than or equal to 20 tpy.

XVII.F.5.g.(iv) By July 1, 2016, facilities with uncontrolled actual VOC emissions less than or equal to 6 tpy.

XVII.F.5.g. If a component is difficult, unsafe, or inaccessible to monitor, the owner or operator shall not be required to monitor the component until it becomes feasible to do so.

XVII.F.5.g.(i) Difficult to monitor components are those that cannot be monitored without elevating the monitoring personnel more than two meters above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

XVII.F.5.g.(ii) Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

XVII.F.5.g.(iii) Inaccessible to monitor components are those that are buried, insulated in a manner that prevents access to the components by a

monitor probe, or obstructed by equipment or piping that prevents access to the components by a monitor probe.

XVII.F.6 Leak detection requiring repair: Leaks shall be identified utilizing the methods listed in this Section XVII.F.6.a. through XVII.F.6.d. Only leaks detected pursuant to this Section XVII.F.6. shall require repair under Section XVII.F.

XVII.F.6.a. For Method 21 monitoring at existing facilities, a leak is any concentration of hydrocarbon above 2,000 parts per million (ppm), except for existing well production facilities where leak is defined as any concentration of hydrocarbon above 500 ppm.

XVII.F.6.b. For Method 21 monitoring at facilities constructed after May 1, 2014, a leak is any concentration of hydrocarbon above 500 ppm.

XVII.F.6.c. For infra-red camera and AVO monitoring, a leak is any detectable emissions not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

XVII.F.6.d. For other Division approved monitoring devices or methods, leak identification requiring repair will be established as set forth in the Division's approval.

XVII.F.7. Repair and remonitoring

XVII.F.7.a. Except as provided in Section XVII.F.7.b. below, the first attempt to repair a leak shall be made no later than five (5) working days after discovery, unless parts are unavailable, the equipment requires shutdown to complete repair, or other good cause exists. If parts are unavailable, they shall be ordered promptly and the repair shall be made within fifteen (15) working days of receipt of the parts. If shutdown is required, the leak shall be repaired during the next scheduled shutdown. If delay is attributable to other good cause, repairs shall be completed within fifteen (15) working days after the cause of delay ceases to exist.

XVII.F.7.b. Repairs to major gas leaks that are discovered within 1,320 feet of a building unit or designated outside activity area shall be made no later than 24 hours after discovery. If a repair is not possible with 24 hours, the well shall be shut down until a repair can be made. If shutting down the well will not stop the leak, demonstrable efforts should be made to minimize the leak within the first 24 hours.

XVII.F.7.c. Within fifteen (15) working days of completion of a repair, the leaks shall be remonitored to verify the repair was effective.

XVII.F.7.d. Leaks discovered pursuant to the leak detection methods of Section XVII.F. shall not be subject to enforcement by the Division unless the owner or operator fails to perform the required repairs in accordance with Section XVII.F.7.

XVII.F.7.e. For leaks identified using an Approved Instrument Based Monitoring Method, owners and operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section XVII.F.7. or conducting follow-up monitoring using Method 21 within five (5) working days of the leak detected. If the follow-up Method 21 monitoring shows that the leak concentration is less than or equal to 2,000 ppm hydrocarbon for existing

facilities (other than existing well production facilities), or 500 ppm for new facilities or existing well production facilities, then the emission shall not be considered a leak for purposes of this Section.

XVII.F.8. Recordkeeping: The owner or operator of each facility subject to the inspection and maintenance requirements in this Section XVII.F. shall maintain the following for a period of two (2) years and make them available to the Division upon request.

XVII.F.8.a. Documentation of the pre-start-up pressure tests for new well production facilities;

XVII.F.8.b. The date and site information for each inspection;

XVII.F.8.c. A list of the leaking components and the monitoring method used to determine the presence of the leak;

XVII.F.8.d. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;

XVII.F.8.e. The date the leak was repaired~~ed~~;

XVII.F.8.f. The delayed repair list including the basis for placing leaks on the list;

XVII.F.8.g. The date the leak was remonitored to verify the effectiveness of the repair, and the results of the remonitoring; and

XVII.F.8.h. A list of identification numbers for components that are designated as unsafe or inaccessible to monitor, as described in Section XVII.F.5.g., an explanation for each component stating why the component is so designated, and the plan for monitoring such component(s).

XVII.F.9. Reporting: The owner or operator of each facility subject to the inspection and maintenance requirements in Section XVII.F. shall submit a single annual report on or before April 30th of each year summarizing inspection and maintenance activities at all of their subject facilities during the previous calendar year. Reports will be made publicly available on the APCD Website and searchable by API well number, APEN permit number, operator, date, and geographic area. In addition to this information, This-the report shall also contain ~~at a minimum~~ the following information:

XVII.F.9.a. The number of facilities inspected;

XVII.F.9.b. The total number of inspections;

XVII.F.9.c. The total number of leaks identified, broken out by component type;

XVII.F.9.d. The total number of leaks repaired;

XVII.F.9.e. Each major gas leak discovered and how quickly it was repaired;

XVII.F.9.~~fe~~. The number of leaks on the delayed repair list as of December 31st; and

XVII.F.9.~~gf~~. Each report shall be accompanied by a self-certification form. The form shall contain a certification by a responsible official of the truth, accuracy, and completeness of such form, report, or certification stating that, based on

information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

XVII.G. (State Only) Control of emissions from well production facilities

XVII.G.1. Well Operation and Maintenance: On or after August 1, 2014, during normal operation gas coming off a separator produced from any newly constructed, hydraulically fractured, or recompleted oil and gas well must either be routed to a gas gathering line or controlled by air pollution control equipment that achieves an average hydrocarbon control efficiency of 95% from the date of first production. If a combustion device is used, it shall have a design destruction efficiency of at least 98% of hydrocarbons.

XVII.H. (State Only) Venting during downhole well maintenance and unloading events

XVII.H.1. Well Maintenance: Beginning May 1, 2014, hydrocarbon emissions from flowing wells must be captured or controlled during downhole well maintenance or servicing activities, unless venting is necessary for safety.

XVII.H.1.a. Operators shall use best management practices to minimize the need for well venting associated with downhole well maintenance and liquids unloading. During liquids unloading events, any means of creating differential pressure will first be used to attempt to unload the liquids from the well without venting. If these methods are not successful in unloading the liquids from the well, the well may be vented to the atmosphere to create the necessary differential pressure to bring the liquids to the surface.

XVII.H.1.b. Venting will be minimized to the extent possible, using best management practices during the well maintenance and liquids unloading events in XVII.H.1.a. The owner and/or operator shall be present on-site during any planned well maintenance and liquids unloading event in XVII.H.1.a. and shall ensure that any venting to the atmosphere is limited to the maximum extent practicable.

XVII.H.1.c. Records of the cause, date, time, and duration of venting events under this Section XVII.H. will be kept and made available to the Division upon request.

XVIII. (State Only) Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations

XVIII.A. Applicability

This section applies to pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations, natural gas compressor stations, and/or natural gas drip stations).

XVIII.B. Definitions

XVIII.B.1. "Affected Operations" shall mean pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations, natural gas compressor stations, and/or natural gas drip stations).

XVIII.B.2. "Enhanced Maintenance" is specific to high-bleed devices and shall include but is not limited to cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; and eliminating unnecessary valve positioners.

- XVIII.B.3. "High-Bleed Pneumatic Controller" shall mean a pneumatic controller that is designed to have a constant bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.
- XVIII.B.4. "Low-Bleed Pneumatic controller" shall mean a pneumatic controller that is designed to have a constant bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.
- XVIII.B.5. "Natural Gas Processing Plant" shall mean any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.
- XVIII.B.6. "No-bleed Pneumatic Controller" shall mean any pneumatic controller that is not using hydrocarbon gas as the valve's actuating gas.
- XVIII.B.7. "Pneumatic Controller" shall mean an instrument that is actuated using natural gas pressure and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow and temperature.

XVIII.C. Emission Reduction Requirements

The owners and operators of affected operations shall reduce emissions of volatile organic compounds from pneumatic controllers associated with affected operations as follows:

XVIII.C.1. In the 8-Hour Ozone Control Area:

XVIII.C.1.a. All pneumatic controllers placed in service on or after February 1, 2009, shall emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.1.c.

XVIII.C.1.b. All high-bleed pneumatic controllers in service prior to February 1, 2009 shall be replaced or retrofit such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, by May 1, 2009, unless allowed pursuant to Section XVIII.C.1.c.

XVIII.C.1.c. All high-bleed pneumatic controllers that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.1.c.(i) For high-bleed pneumatic controllers in service prior to February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and /or process purposes by March 1, 2009. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.1.c.(ii) For high-bleed pneumatic controllers placed in service on or after February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and /or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.2. Statewide:

XVIII.C.2.a. All pneumatic controllers placed in service on or after May 1, 2014, shall:

XVIII.C.2.c.(i) Emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.; or

XVIII.C.2.c.(ii) Utilize no-bleed pneumatic controllers where on-site electrical grid power is being used and is technically and economically feasible.

XVIII.C.2.b. All high-bleed pneumatic controllers in service prior to May 1, 2014, shall be replaced or retrofitted by May 1, 2015, such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.

XVIII.C.2.c. All high-bleed controllers that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.2.c.(i) All high-bleed pneumatic controllers in service prior to May 1, 2014, the owner/operator shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and/or process purposes by March 1, 2015. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.2.c.(ii) For high-bleed pneumatic controllers placed in service on or after May 1, 2014, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and/or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.D. Monitoring

This section applies only to high-bleed pneumatic controllers identified in Sections XVIII.C.1.c. and XVIII.C.2.c.

XVIII.D.1. In the 8-Hour Ozone Control Area

XVIII.D.1.a. Effective May 1, 2009, each high-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.1.b. Effective May 1, 2009, each high-bleed pneumatic controller shall be inspected on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2 , and maintain the device according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.D.2. Statewide:

XVIII.D.2.a. Effective May 1, 2015, each high-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.2.b. Effective May 1, 2015, each high-bleed pneumatic controller shall be inspected on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2 , and maintain the device according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.E. Recordkeeping

This section applies only to high-bleed pneumatic controllers identified in Sections XVIII.C.1.c. and XVIII.C.2.c.

XVIII.E.1. The owner or operator of affected operations shall maintain a log of the total number of high-bleed pneumatic controllers and their associated controller numbers per facility, the total number of high-bleed pneumatic controllers per company and the associated justification that the high-bleed pneumatic controllers must be used pursuant to Sections XVIII.C.1.c. and XVIII.C.2.c. The log shall be updated on a monthly basis.

XVIII.E.2. The owner or operator shall maintain a log of enhanced maintenance which shall include, at a minimum, inspection dates, the date of the maintenance activity, high-bleed pneumatic controller number, description of the maintenance performed, results and date of any corrective action taken, and the printed name and signature of the individual performing the maintenance. The log shall be updated on a monthly basis.

XVIII.E.3. Records of enhanced maintenance of pneumatic controllers shall be maintained for a minimum of three years and readily made available to the Division upon request.

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XIX. Statements of Basis, Specific Statutory Authority and Purpose

The Local Community Organizations adopt the Statement of Basis and Purpose proposed by the APCD.

EXHIBIT I.

LOCAL COMMUNITY ORGANIZATIONS’ FINAL ECONOMIC IMPACT ANALYSIS PER § 25-7-110.5(4), C.R.S.

For proposed revisions to
Colorado Air Quality Control Commission
Regulation Number 7 (5 CCR 1001-9)

I. INTRODUCTION

This final economic impact analysis will cover only the changes the Local Community Organizations have made to the Air Quality Control Division’s (APCD) proposal. The Local Community Organizations appreciate the assistance from the APCD in the creation of this final economic impact analysis.

II. OVERVIEW OF PROPOSED REGULATORY CHANGES

The Local Community Organizations are proposing revisions to the APCD’s proposed AQCC Regulation Number 7. This Regulation Number 7 rulemaking package adopts nearly all of the changes proposed by the Colorado Air Pollution Control Division but amends specific sections to accomplish the following:

- 1) Reduce nearby residents’ exposure to air toxics by requiring operators of facilities within 1,320 feet of a building unit or outdoor activity area to
 - a. control VOCs down to 2 TPY,
 - b. conduct more frequent inspections, and
 - c. repair “major leaks” within 24 hours.
- 2) Increase transparency by requiring annual inspection reports to be posted online and accessible by the public.

III. COST/BENEFIT ANALYSIS:

A. Control Requirements for Petroleum Storage Tanks

The Local Community Organizations have proposed changes to require that tanks within 1,320 feet (1/4 mile) of a building unit or designated outdoor activity area must utilize air pollution control equipment if the tanks have uncontrolled actual emissions of equal or greater than two (2) tons per year.

The proposed APCD regulations would require operators with tanks that have uncontrolled emissions of at least **six (6) tons** per year to use emission control devices capable of achieving 95% control efficiency of volatile organic compounds (VOCs). Currently, the Colorado Oil and Gas Conservation Commission (COGCC) requires all tanks with uncontrolled emissions of VOCs

of five (5) tons per year or greater that are located within 1,320 feet of a Building Unit, or a Designated Outside Activity Area to use an emission control device capable of achieving 95% control efficiency of VOCs. (COGCC Rule 805.b.(2)). Therefore, this change only will affect those tanks that emit from 2-5 tons of VOCs per year.

1. General Cost Estimates for Flares

Using the data obtained from the APCD Initial Economic Impact Analysis, we assume that the estimated annualized cost of a flare control device with auto-igniter is about \$6,287.

2. Annualized Cost for Buffer Bottles

As reported in the Division's initial economic impact analysis, the annualized costs for buffer bottles is \$3,024 per unit.

3. Lowering Statewide Condensate Tank Control Threshold (from 6(5) tpy to 2 tpy)

The Local Community Organization is proposing to lower the uncontrolled VOC emission control threshold from the state-proposed 6 tpy to 2 tpy on all tanks within 1,320 feet of a Building Unit, or a Designated Outside Activity Area.

As stated above, the COGCC currently requires tanks to control VOCs to five (5) tons per year within 1,320 feet of a home so the regulation only affects those tanks that emit two (2) to five (5) tpy.

Using numbers obtained from the APCD, there are 1,506 tanks that are emitting between 2-5 tpy VOCs.

Of this number, at least 2/3 of the tanks would not be located within 1,320 feet of a home or designated outdoor recreation area. The COGCC supplied data during the setback hearing that indicated that approximately 26% of new and expanded well sites were located within 1,000 feet of a building unit. (COGCC analysis is attached). Expanding the area from 1,000 to 1,320 feet we have allowed for the percentage of wells affected to climb to 1/3 or 33%. Therefore, 2/3 of the potential tanks affected will not be affected by this regulation and are listed in Table 1 as "cancelled tanks".

Using the assumption of 33% of tanks being within 1,230 feet of a building unit we get 497 tanks.

Table 1: Tank Battery Analysis						
	2-3 TPY	3-4 TPY	4-5 TPY	5-6 TPY	Total Tanks 2-5 TPY	Total Tanks 2-6 TPY
Tanks	610	485	411	374	1,506	1,880
Cancelled Tanks	409	325	275	251	1,009	1,260
TOTAL AFFECTED TANKS (2-5 tpy)	201	160	136	123	497	620

The annual cost of installing 497 flare control devices is about \$3,125,000 with an average cost effectiveness of about \$1,884.5 per ton of VOCs reduced. See Table 2. VOC reduction in the 497 tanks that are within 1,320 feet of a building unit or designated outside activity area AND emit ≥ 2 tpy of VOCs but less than 5 tpy of VOCs was calculated by summing the VOC emissions of ALL tanks that emit ≥ 2 tpy but less than 5 tpy and then multiplying this sum by 0.33, assuming only 33% of all such tanks lie within 1,320 feet of a building unit or designated outside activity area. The emission data came from the APCD.

Table 2: Tanks over 6 tpy – Control Cost Estimates for Flare Control Devices (inc. buffer bottle)				
Affected Tanks [count]	Each Flare + buffer bottle Annualized Cost	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [\$/ton]
497	\$9,310.8	\$4,627,467.6	1,658	\$2,791

B. Emission Capture Requirements for Controlled Petroleum Storage Tanks

In order to prevent leaks and ensure that oil and gas facilities closest to homes and schools are being properly maintained, the Local Community Organizations are proposing that tanks within 1,320 feet of a building unit or designated outdoor recreation area be subject to more frequent instrument based monitoring using Method 21, an IR camera or other Division approved monitoring device or method. As proposed by the APCD, the frequency of this instrument based monitoring will depend on the level of uncontrolled actual emissions from the tank.

Table 3: Proposed Tiering for Instrument Based Tank Inspections - ¼ mile of building units				
Tank Uncontrolled Actual VOC Emissions	Number of Tanks Affected	Inspection Frequency	Additional Number of Inspections	Additional Inspection Costs
≥ 2 tpy to ≤ 6 tpy	497	Annually	497	\$98,406
>6 tpy to ≤ 12 tpy	459	Quarterly	1,376	\$272,448
>12 tpy to 50 tpy	962	Monthly	7,698	\$1,524,204

In assessing the cost-effectiveness of the proposed requirements, the Local Community Organizations first calculated the number of tanks that would be affected (1/3 in each category of tanks) and then the additional inspections necessary. That is, going from annual inspection to quarterly inspections would require an additional three inspections, quarterly to monthly would require an additional eight inspections per tank. These figures were then multiplied by the state's estimate of \$198 per inspection to come up with the figures in Table 3.

C. Leak Detection and Repair Requirements for Compressor Stations and Well Production Facilities

The Local Community Organizations have requested that major leaks of over 10,000 ppm within 1,320 feet of building units should be repaired within 24 hours. We do not believe there will be

any additional costs associated with this practice since the leaks would already have to be repaired within five days and most operators will make immediate repairs if major leaks are discovered for safety purposes and to conserve the oil and gas.

D. Require the APCD to Place Annual Inspection Reports on their Website

The Local Community Organizations have requested that the APCD assist in finalizing this economic impact analysis. They hope to receive that information as to the cost of this provision in the coming weeks. In the meantime, we would expect that the COGCC would be willing to post the annual inspection reports on its website. The cost to post on the COGCC website would be much less given the website is already set-up to allow the public to search by API well number.

IV. CONCLUSION

The Local Community Organizations estimate that their requested revisions to increase tank controls within 1,320 feet of building units will cost \$4,627,467– reducing 1,658 tpy of VOCs at a cost of \$2,791 tons/year. The total cost for the increased inspection schedules within 1,320 feet of homes is \$1,895,058.

The cost to the APCD for design and maintenance of a website that will contain annual inspection reports is still to be determined.

LGC EXHIBIT A. ALTERNATIVE PROPOSED REGULATION

AMENDED REVISIONS BY THE LGC TO:

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT Air Quality Control Commission

REGULATION NUMBER 7

CONTROL OF OZONE VIA OZONE PRECURSORS AND CONTROL OF HYDROCARBONS VIA OIL AND GAS EMISSIONS

(EMISSIONS OF VOLATILE ORGANIC COMPOUNDS AND NITROGEN OXIDES)

Field Code Changed

5 CCR 1001-9

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II. General Provisions

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II.B. Exemptions

Emissions of the organic compounds listed as having negligible photochemical reactivity in the common provisions definition of Negligibly Reactive Volatile Organic Compound are exempt from the provisions of this regulation.

(State Only) Notwithstanding the foregoing exemption, hydrocarbon emissions from oil and gas operations, including methane and ethane, are subject to this regulation as set forth in Sections XVII. and XVIII.

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XVII. (State Only, except Section XVII.E.3.a. which was submitted as part of the Regional Haze SIP) Statewide Controls for Oil and Gas Operations and Natural Gas-Fired Reciprocating Internal Combustion Engines

XVII.A. (State Only) Definitions

XVII.A.1 "Air Pollution Control Equipment," as used in this Section XVII, means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment and pollution prevention devices and processes intended to reduce uncontrolled actual emissions that comply with the requirements of Section XVII.B.2.e.

- XVII.A.2. "Approved Instrument Based Monitoring Method," as used in this Section XVII. means an infra-red camera, Method 21, or other Division approved instrument based monitoring device or method. If an owner/operator elects to use a Division approved Continuous Emission Monitoring program, the Division may approve a streamlined inspection and reporting program for such operations. Any instrument based monitoring method approved by the Division under this definition must be at least as effective as Method 21 or an infra-red camera.
- XVII.A.3. "Auto-Igniter" means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust volatile organic compound emissions.
- XVII.A.4. "Component" means each pump seal, compressor seal, flange, pressure relief device, connector, open ended line, and valve that contains or contacts a process stream with hydrocarbons. Process streams consisting of glycol, amine, produced water, or methanol are not components for purposes of this Section XVII.
- XVII.A.5. "Connector" means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Jointed fittings welded completely around the circumference of the interface are not considered connectors.
- XVII.A.6. "Date of First Production" means the date reported to the COGCC as the "first date of production."
- XVII.A.7. "Glycol Natural Gas Dehydrator" means any device in which a liquid glycol (including ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.
- XVII.A.8. "Multi-Well Site" means a common well pad from which multiple wells may be drilled to various bottomhole locations.
- XVII.A.9. "Natural Gas Compressor Station" means a facility which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure and recompress natural gas prior to processing.
- XVII.A.10. "Normal Operation" means all periods of operation, excluding malfunctions as defined in Section I.G. of the Common Provisions regulation. For storage tanks at well production facilities, normal operation includes but is not limited to liquid dumps from the separator.
- XVII.A.11. "Stabilized" when used to refer to crude oil, condensate, intermediate hydrocarbon liquids, or produced water means that the vapor pressure of the liquid is sufficiently low to prevent the production of vapor phase upon transferring the liquid to an atmospheric pressure in a storage tank, and that any emissions that occur are limited

to those commonly referred to within the industry as working, breathing, and standing losses.

XVII.A.12. “Storage Tank” means any fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. Storage vessel is as defined in 40 CFR Part 60, Subpart OOOO. Storage tanks may be located at a well production facility or other location.

XVII.A.13. “Unsafe to Monitor” means a component is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of such monitoring.

XVII.A.14. “Visible Emissions” means observations of smoke for any period or periods of duration greater than or equal to one (1) minute in any fifteen (15) minute period during normal operation. Visible emissions do not include radiant energy or water vapor.

XVII.A.15. “Well Production Facility” means all equipment at a single stationary source directly associated with one or more oil wells or gas wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

XVII.B. (State Only) General Provisions

XVII.B.1. General requirements for prevention of emissions and good air pollution control practices for all oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.

XVII.B.1.a. All intermediate hydrocarbon liquids collection, storage, processing, and handling operations, regardless of size, shall be designed, operated, and maintained so as to minimize leakage of volatile organic compounds to the atmosphere to the extent reasonably practicable.

XVII.B.1.b. At all times, including periods of start-up and shutdown, the facility and air pollution control equipment shall be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether or not acceptable operating and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

XVII.B.2. General requirements for air pollution control equipment, flares, and combustion devices used to comply with Section XVII.

XVII.B.2.a. All air pollution control equipment shall be operated and maintained pursuant to the manufacturing specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file. In addition, all such air pollution control equipment shall be adequately designed and sized to achieve the control efficiency rates and to handle reasonably foreseeable fluctuations in emissions of volatile organic compounds and hydrocarbons during normal operations. Fluctuations in emissions that occur when the separator dumps into the tank are reasonably foreseeable.

XVII.B.2.b. If a flare or other combustion device is used to control emissions of hydrocarbons, it shall be enclosed, have no visible emissions during normal operations, and be designed so that an observer can, by means of visual observation from the outside of the enclosed flare or combustion device, or by other means approved by the Division, determine whether it is operating properly.

XVII.B.2.c. Any of the effective dates for installation of controls on storage tanks, dehydrators, and/or internal combustion engines may be extended at the Division's discretion for good cause shown.

XVII.B.2.d. Auto-igniters: All combustion devices used to control emissions of hydrocarbons shall be equipped with and operate an auto-igniter as follows:

XVII.B.2.d.(i) All combustion devices installed on or after May 1, 2014, will be equipped with an operational auto-igniter upon installation of the combustion device.

XVII.B.2.d.(ii) All combustion devices installed before May 1, 2014, will be equipped with an operational auto-igniter by or before May 1, 2016, or after the next combustion device planned shutdown, whichever comes first.

XVII.B.2.e. Alternative emissions control equipment shall qualify as air pollution control equipment, and may be used in lieu of, or in combination with, combustion devices and vapor recovery units to achieve the emission reductions required by this Section XVII, if the Division approves the equipment, device or process. As part of the approval process the Division, at its discretion, may specify a different control efficiency than the control efficiencies required by this Section XVII.

XVII.B.3. Oil refineries are not subject to Section XVII.

XVII.B.4. Glycol natural gas dehydrators and internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63, a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard ("NSPS") under 40 CFR Part 60 are not subject to this Section XVII.

XVII.C. (State Only) Emission reduction from storage tanks at oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.

XVII.C.1. Control requirements for storage tanks

XVII.C.1.a. Beginning May 1, 2008, owners or operators of all storage tanks storing condensate with uncontrolled actual emissions of volatile organic compounds equal to or greater than twenty (20) tons per year based on a rolling twelve-month total must operate air pollution control equipment that has an average control efficiency of at least 95% for VOCs.

XVII.C.1.b. Owners or operators of all storage tanks with uncontrolled actual emissions of volatile organic compounds equal to or greater than six (6) tons per year based on a rolling twelve-month total must operate air pollution control equipment that achieves an average hydrocarbon control efficiency of 95%. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons.

XVII.C.1.b.(i) A storage tank constructed on or after May 1, 2014, must be in compliance by the date that the storage tank commences operation.

XVII.C.1.b.(ii) A storage tank constructed before May 1, 2014, must be in compliance by May 1, 2015.

XVII.C.1.b.(iii) A storage tank not otherwise subject to Sections XVII.C.1.b.(i) or XVII.C.1.b.(ii), above, that increases uncontrolled actual emissions to six tons VOC or more per year on a rolling twelve month basis after May 1, 2014, must be in compliance within sixty days of discovery of the emissions increase.

XVII.C.1.c. Control requirements within 90 days of the date of first production.

XVII.C.1.c.(i) Beginning May 1, 2014, owners or operators of storage tanks at well production facilities shall collect and control emissions by routing emissions to operating air pollution control equipment during the first 90 calendar days after the date of first production. The air pollution

control equipment shall achieve an average hydrocarbon control efficiency of 95%. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons. Except that this requirement does not apply to storage tanks that are projected to have emissions less than 1.5 tons of VOC during the first 90 days after the date of first production.

XVII.C.1.c.(ii) The air pollution control equipment and any associated monitoring equipment required pursuant to Section XVII.C.1.c., above, may be removed at any time after the first 90 calendar days as long as the source can demonstrate that uncontrolled actual emissions from the storage tank are below the threshold in Section XVII.C.1.b., above.

XVII.C.2. Capture requirements for storage tanks that are fitted with air pollution control equipment as required by Sections XII.D. or XVII.C.1.

XVII.C.2.a. Beginning on the applicable compliance date specified in Section XVII.C.1.b., owners and operators of storage tanks shall route all hydrocarbon emissions to air pollution control equipment, and shall operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation unless venting is reasonably required for maintenance, gauging, or safety of personnel and equipment.

XVII.C.2.b. Beginning on the applicable compliance date specified in section XVII.C.1.b., owners and operators of storage tanks shall develop, certify, and implement a document Storage Tank Emission Management System (STEM) plan to identify appropriate strategies to minimize emissions from venting at thief hatches (or other access points to a storage tank) and pressure relief devices during normal operation. As part of STEM, owners and operators shall evaluate and employ appropriate control technologies, monitoring practices, operational practices, and/or other strategies designed to meet the requirements set forth in Section XVII.C.2.a., above, and will update the STEM plan as necessary to achieve or maintain compliance. Owners and operators are not required to develop and implement STEM for storage tanks containing only stabilized liquids. The minimum elements of STEM are listed below.

XVII.C.2.b.(i) STEM must include a monitoring strategy that incorporates the minimum monitoring frequency set forth in Section XVII.F.5.e., procedures for evaluating ongoing storage tank emission capture performance, and, if applicable, the selected strategies.

XVII.C.2.b.(ii) STEM must include a certification by the owner or operator that the selected STEM strategy or strategies are designed to minimize emissions from storage tanks and associated equipment components at

the facility or facilities, including thief hatches and pressure relief devices.

XVII.C.3. Monitoring: The monitoring strategy of each STEM plan must include monitoring in accordance with Approved Instrument Based Monitoring Methods, as specified in Section XVII.F.5.

XVII.C.3.a. In addition to any applicable Approved Instrument Based Monitoring Methods, audio, visual, olfactory ("AVO") inspection of the storage tank and any associated equipment (i.e. separator, air pollution control equipment, or other pressure reducing equipment), must be completed as often as liquids are loaded out from the storage tank. However, AVO inspection is required no more frequently than every seven (7) days or less frequently than every thirty (30) days. AVO monitoring is not required for components and tanks that are unsafe to monitor. AVO inspection must include, at a minimum:

XVII.C.3.a.(i) Visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are enclosed and properly sealed;

XVII.C.3.a.(ii) Visual inspection or monitoring of the air pollution control equipment to ensure that it is operating, including that the pilot light is lit on combustion devices used as air pollution control equipment;

XVII.C.3.a.(iii) If a flare or other combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light, to ensure they are functioning properly;

XVII.C.3.a.(iv) Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the storage tank to the air pollution control equipment are open; and

XVII.C.3.a.(v) If a flare or other combustion device is used, inspection of the device for the presence of absence of smoke. If smoke is observed, either the equipment will be immediately shut-in to investigate that potential cause for smoke and perform repairs, as necessary, or Method 22 shall be conducted to determine whether visible emissions are present for a period of at least one (1) minute in fifteen (15) minutes.

XVII.C.4. Recordkeeping: The owner or operator of each storage tank subject to XII.D. or XVII.C. must maintain records of STEM as applicable, including the plan, any updates, and the certification, to be made available to the Division upon request. In addition, for a period of two years, the owner or operator must maintain records of any required monitoring and make them available to the Division upon request, including:

XVII.C.4.a. The AIRS ID for the storage tank.

XVII.C.4.b. The date and duration of any period where the thief hatch, pressure relief device, or other access point are found to be venting hydrocarbon emissions.

XVII.C.4.c. The date and duration of any period where the air pollution control equipment is not operating.

XVII.C.4.d. Where a flare or other combustion device is being used, the date and result of any Method 22 test.

XVII.C.4.e. The timing of and efforts made to eliminate venting, restore operation of air pollution control equipment, and mitigate visible emissions.

XVII.D. (State Only) Emission reductions from glycol natural gas dehydrators

XVII.D.1. Beginning May 1, 2008, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, drip station or gas-processing plant subject to control requirements pursuant to Section XVII.D.2., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent through the use of a condenser or air pollution control equipment.

XVII.D.2. The control requirement in Section XVII.D.1. shall apply where:

XVII.D.2.a. Actual uncontrolled emissions of volatile organic compounds from the glycol natural gas dehydrator are equal to or greater than two tons per year; and

XVII.D.2.b. The sum of actual uncontrolled emissions of volatile organic compounds from any single glycol natural gas dehydrator or grouping of glycol natural gas dehydrators at a single stationary source is equal to or greater than 15 tons per year. To determine if a grouping of dehydrators meets or exceeds the 15 tons per year threshold, sum the total actual uncontrolled emissions of volatile organic compounds from all individual dehydrators at the stationary source, including those with emissions less than two tons per year.

XVII.D.3. Beginning May 1, 2015, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, and drip station or gas-processing plant subject to control requirements pursuant to Section XVII.D.4., shall reduce uncontrolled actual emissions of hydrocarbons by at least 95 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons.

XVII.D.4. The control requirement in Section XVII.D.3. shall apply where:

XVII.D.4.a. Actual uncontrolled emissions of volatile organic compounds from a single new glycol natural gas dehydrator are equal to or greater than two tons per year; or

XVII.D.4.b. Actual uncontrolled emissions of volatile organic compounds from a single existing glycol natural gas dehydrator are equal to or greater than six (6) tons per year, or two (2) tons per year if the glycol natural gas dehydrator is located within 1,320 feet of a building unit or designated outside activity area.

XVII.D.4.c. For purposes of Section XVII.D.4.:

XVII.D.4.c.(i) Building Unit shall mean a residential building unit, and every five thousand (5,000) square feet of building floor area in commercial facilities or every fifteen thousand (15,000) square feet of building floor area in warehouses that are operating and normally occupied during working hours.

XVII.D.4.c.(ii) A designated outside activity area shall mean an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of public assembly owned or operated by a local government, which the local government seeks to have established as a Designated Outside Activity Area; or an outdoor venue or recreation area where ingress to or egress from could be impeded in the event of an emergency condition at an oil and gas location less than three hundred and fifty (350) feet from the venue due to the configuration of the venue and the number of persons known or expected to simultaneously occupy the venue on a regular basis.

XVII.E. Control of emissions from new, modified, existing, and relocated natural gas fired reciprocating internal combustion engines.

XVII.E.1. (State Only) The requirements of this Section XVII.E. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.2. (State Only) New, Modified and Relocated Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.2.a. Except as provided in Section XVII.E.2.b. below, the owner or operator on any natural gas fired reciprocating internal combustion engine that is either constructed or relocated to the state of Colorado from another state, on or after the date listed in the table below shall operate and maintain each engine according to the manufacturer's written instructions or procedures to the

extent practicable and consistent with technological limitations and good engineering and maintenance practices over the entire life of the engine so that it achieves the emission standards required in Section XVII.E.2.b. Table 1 below.

XVII.E.2.b. Actual emissions from natural gas fired reciprocating internal combustion engines shall not exceed the emission performance standards in Table 1 below as expressed in units of grams per horsepower-hour (G/hp-hr)

TABLE 1				
Maximum Engine Hp	Construction or Relocation Date	Emission Standards is G/hp-hr		
		NOx	CO	VOC
< 100 Hp	Any	NA	NA	NA
≥100 Hp	On or after January 1, 2008	2.0	4.0	1.0
and < 500 Hp	On or after January 1, 2011	1.0	2.0	0.7
≥500 Hp	On or after July 1, 2007	2.0	4.0	1.0
	On or after July 1, 2010	1.0	2.0	0.7

XVII.E.3. Existing Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.3.a. (Regional Haze SIP) Rich Burn Reciprocating Internal Combustion Engines

XVII.E.3.a.(i) Except as provided in Sections XVII.3.1.(i)(b) and (c) and XVII.E.3.a.(ii), all rich burn reciprocating internal combustion engines with a manufacturer's name plate design rate greater than 500 horsepower, constructed or modified before February 1, 2009 shall install and operate both a non-selective catalytic reduction system and an air fuel controller by July 1, 2010. A rich burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of less than 2% by volume.

XVII.E.3.a.(i)(a) All control equipment required by this Section XVII.E.3.a. shall be operated and maintained pursuant to manufacturer specifications or equivalent to the extent

practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file.

XVII.E.3.a.(i)(b) Internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63, a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard under 40 CFR Part 60 are not subject to this Section XVII.E.3.a.

XVII.E.3.a.(i)(c) The requirements of this Section XVII.E.3.a. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.3.a.(ii) Any rich burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than \$ 5,000 per ton of combined volatile organic compound and nitrogen oxides emission reductions (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.a. Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

XVII.E.3.b. (State Only) Lean Burn Reciprocating Internal Combustion Engines

XVII.E.3.b.(i) Except as provided in Section XVII.E.3.b.(ii), all lean burn reciprocating internal combustion engines with a manufacturer's nameplate design rate greater than 500 horsepower shall install and operate an oxidation catalyst by July 1, 2010. A lean burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of 2% by volume, or greater.

XVII.E.3.b.(ii) Any lean burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than \$ 5,000 per ton of volatile organic compound emission reduction (this value shall be adjusted for future applications according to the current day consumer price index)

is exempt complying with Section XVII.E.3.b.(i). Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

XVII.F. (State Only) Leak detection and repair program for well production facilities, storage tanks, and compressor stations

XVII.F.1. Beginning January 1, 2015, owners and operators of well production facilities and compressor stations will identify and repair leaks from components at these facilities in accordance with the requirements of this Section XVII.F. The following shall apply in lieu of any directed inspection and maintenance program requirements established pursuant to Regulation Number 3, Part B, Section III.D.2.

XVII.F.2. Owners and operators of well production facilities or natural gas compressor stations that monitor components as part of this Section XVII.F. may opt to estimate emissions from components for the purpose of evaluating the applicability of component fugitive emissions to Regulation Number 3 by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017).

XVII.F.3. Owners and operators of well production facilities or natural gas compressor stations shall utilize the Approved Instrument Based Monitoring Method and AVO program as outlined in Section XVII.F. AVO monitoring is not required of components and tanks that are unsafe to monitor or inaccessible to monitor, pursuant to XVII.F.5.g.

XVII.F.4. Inspection schedules for natural gas compressor stations: Beginning January 1, 2015, owners and operators of natural gas compressor stations shall inspect components for leaks using an Approved Instrument Based Monitoring Method, in accordance with the following Table 2, except for components subject to XVII.F.5.g. For purposes of this Section XVII.F.4., fugitive emissions shall be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), of other Division approved method.

Table 2	
Fugitive VOC Emissions (tpy)	Inspection Frequency
>0 and ≤ 12	<u>Semi-Annually</u>

> 12 and ≤ 50	Quarterly
> 50	Monthly

XVII.F.5. Requirements for well production facilities and/or storage tanks

XVII.F.5.a. Beginning August 1, 2014, all new well production facilities shall have a documented pressure test performed on all equipment and piping prior to start up. Documentation of this 90 day testing and monitoring shall be provided in the first annual report to the Division, as required by Section XVII.F.9.

XVII.F.5.b. Beginning January 1, 2015, within 90 days of startup of all new well production facilities and/or storage tanks, owners and/or operators shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method. Such action shall qualify as an inspection pursuant to the inspection frequency schedule in Table 3.

XVII.F.5.c. Consistent with the provisions of XVII.F.5.f., owners and operators of existing well production facilities and/or storage tanks shall identify and repair leaks using an Approved Instrument Based Monitoring Method, in accordance with the implementation schedule in XVII.F.5.e. Inspection frequency shall be determined according to Table 3.

XVII.F.5.d. Consistent with the provisions of XVII.F.5.f., owners and operators of new well production facilities and/or storage tanks shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method beginning on January 1, 2015. Inspection frequency shall be determined according to Table 3.

XVII.F.5.e. The estimated uncontrolled actual emissions from storage tanks determine the frequency at which inspections must be performed. If no storage tanks are located at the well production facility or multi-well site, operators will rely on the potential to emit of VOC for all of the emissions sources, including emissions from components located at the facility. All components at a well production facility or storage tank must be inspected:

Table 3	
Threshold (per XVII.F.5.e.) VOC Emissions (tpy, uncontrolled actual for sites with	Inspection Frequency

tanks or PTE for sites without tanks)	
> 0 and ≤ 6	One time using Approved Instrument Based Monitoring Method and thereafter using monthly AVO Every two years with monthly AVO
> 6 and ≤ 12	Semi-annual Annually with monthly AVO
> 12 and ≤ 50	Quarterly with monthly AVO
> 50	Monthly
Multi-well sites without storage tanks after April 15, 2014, that have a PTE > 20 tpy VOC	Monthly

XVII.F.5.f. Phase-in of Approved Instrument Based Monitoring Methods: Owners and operators of existing well production facilities and/or storage tanks shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method, in accordance with the following schedule:

XVII.F.5.f.(i) Beginning January 1, 2015, facilities with uncontrolled actual VOC emissions greater than ~~50~~ 6 tpy or multi-well sites.

~~XVII.F.5.f.(ii) Beginning July January May 1, 2015, facilities with uncontrolled actual VOC emissions greater than 20 6 tpy but less than or equal to 50 tpy.~~

XVII.F.5.f.(iii) Beginning January 1, 2016, facilities with uncontrolled actual VOC emissions ~~greater less than or equal to~~ 6 tpy ~~but less than or equal to 20 tpy.~~

~~XVII.F.5.g.(iv) By July 1, 2016, facilities with uncontrolled actual VOC emissions less than or equal to 6 tpy.~~

XVII.F.5.g. If a component is difficult, unsafe, or inaccessible to monitor, the owner or operator shall not be required to monitor the component until it becomes feasible to do so.

XVII.F.5.g.(i) Difficult to monitor components are those that cannot be monitored without elevating the monitoring personnel more than two meters above a supported surface or are unable to be reached via a

wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

XVII.F.5.g.(ii) Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

XVII.F.5.g.(iii) Inaccessible to monitor components are those that are buried, insulated in a manner that prevents access to the components by a monitor probe, or obstructed by equipment or piping that prevents access to the components by a monitor probe.

XVII.F.6 Leak detection requiring repair: Leaks shall be identified utilizing the methods listed in this Section XVII.F.6.a. through XVII.F.6.d. Only leaks detected pursuant to this Section XVIII.F.6. shall require repair under Section XVII.F.

XVII.F.6.a. For Method 21 monitoring at existing facilities, a leak is any concentration of hydrocarbon above 2,000 parts per million (ppm), except for existing well production facilities where leak is defined as any concentration of hydrocarbon above 500 ppm.

XVII.F.6.b. For Method 21 monitoring at facilities constructed after May 1, 2014, a leak is any concentration of hydrocarbon above 500 ppm.

XVII.F.6.c. For infra-red camera and AVO monitoring, a leak is any detectable emissions not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

XVII.F.6.d. For other Division approved monitoring devices or methods, leak identification requiring repair will be established as set forth in the Division's approval.

XVII.F.7. Repair and remonitoring

XVII.F.7.a. First attempt to repair a leak shall be made no later than five (5) working days after discovery, unless parts are unavailable, the equipment requires shutdown to complete repair, or other good cause exists. If parts are unavailable, they shall be ordered promptly and the repair shall be made within fifteen (15) working days of receipt of the parts. If shutdown is required, the leak shall be repaired during the next scheduled shutdown. If delay is attributable to other good cause, repairs shall be completed within fifteen (15) working days after the cause of delay ceases to exist.

XVII.F.7.b. Within fifteen (15) working days of completion of a repair, the leaks shall be remonitored to verify the repair was effective.

XVII.F.7.c. Leaks discovered pursuant to the leak detection methods of Section XVII.F. shall not be subject to enforcement by the Division unless the owner or operator fails to perform the required repairs in accordance with Section XVII.F.7.

XVII.F.7.d. For leaks identified using an Approved Instrument Based Monitoring Method, owners and operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section XVII.F.7. or conducting follow-up monitoring using Method 21 within five (5) working days of the leak detected. If the follow-up Method 21 monitoring shows that the leak concentration is less than or equal to 2,000 ppm hydrocarbon for existing facilities (other than existing well production facilities), or 500 ppm for new facilities or existing well production facilities, then the emission shall not be considered a leak for purposes of this Section.

XVII.F.8. Recordkeeping: The owner or operator of each facility subject to the inspection and maintenance requirements in this Section XVII.F. shall maintain the following for a period of two (2) years and make them available to the Division upon request.

XVII.F.8.a. Documentation of the pre-start-up pressure tests for new well production facilities;

XVII.F.8.b. The date and site information for each inspection;

XVII.F.8.c. A list of the leaking components and the monitoring method used to determine the presence of the leak;

XVII.F.8.d. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;

XVII.F.8.e. The date the leak was repaired;

XVII.F.8.f. The delayed repair list including the basis for placing leaks on the list;

XVII.F.8.g. The date the leak was remonitored to verify the effectiveness of the repair, and the results of the remonitoring; and

XVII.F.8.h. A list of identification numbers for components that are designated as unsafe or inaccessible to monitor, as described in Section XVII.F.5.g., an explanation for each component stating why the component is so designated, and the plan for monitoring such component(s).

XVII.F.9. Reporting: The owner or operator of each facility subject to the inspection and maintenance requirements in Section XVII.F. shall submit a single annual report on or before April 30th of each year summarizing inspection and maintenance activities at all

of their subject facilities during the previous calendar year. This report shall contain at a minimum the following information:

- XVII.F.9.a. The number of facilities inspected;
- XVII.F.9.b. The total number of inspections;
- XVII.F.9.c. The total number of leaks identified, broken out by component type;
- XVII.F.9.d. The total number of leaks repaired;
- XVII.F.9.e. The number of leaks on the delayed repair list as of December 31st; and
- XVII.F.9.f. Each report shall be accompanied by a self-certification form. The form shall contain a certification by a responsible official of the truth, accuracy, and completeness of such form, report, or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

XVII.G. (State Only) Control of emissions from well production facilities

XVII.G.1 Control Standards

XVII.G.1.A Well Operation and Maintenance: On or after ~~August-January~~ 1, 2015⁴, ~~during normal operation~~ gas coming off a separator produced from any newly ~~—~~constructed, hydraulically fractured, or recompleted oil and gas well must either ~~—~~be routed to a gas gathering line or controlled by air pollution control equipment ~~—~~that achieves an average hydrocarbon control efficiency of 95% from the date of ~~—~~first production. If a combustion device is used, it shall have a design destruction ~~—~~efficiency of at least 98% of hydrocarbons.

XVII.G.1.B Unless otherwise approved by the Division, on or before 90 days from the date of first production from the well or [January 1, 2015], whichever is later, the well must be connected to a gas gathering line. In determining whether to approve an extension of the 90 day period, the Division will consider the economic feasibility of connecting the well to a gas gathering line, the amount of gas being routed to air pollution equipment, the economic feasibility of alternative uses of the gas, the owner/operators' future plans for connecting the well to a gas line, and any other relevant information from the owner or operator. The division will also consider input received from the Colorado Oil & Gas Conservation Commission and will assess economic feasibility subject to a feasibility criterion of \$2,500 per ton.

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XVII.G.2Monitoring: The owner or operator of any well production facility that is using air pollution control equipment to comply with section XVII.G.1.A. shall visually inspect or monitor the air pollution control equipment to ensure that it is operating. In addition, if a flare or other combustion device is used, the owner or operator shall visually inspect the device for visible emissions. These inspections shall occur as often as liquids are loaded out from the well production facility. However, these inspections are required no more frequently than every seven days or less frequently than every 90 days.

XVII.G.3Recordkeeping: The owner or operator of an oil or gas well shall maintain the following records for a period of five years and make them available to the Division upon request.

XVII.G.3.A The date of each visual inspection required under Section XVII.G.2

XVII.G.3.B The date, time and duration of any period where the air pollution control equipment is not operating. The duration of a period of non-operation is from the time that the air pollution control equipment was last observed to be operating until the time the equipment recommences operation.

XVII.G.3.C Where a flare or other combustion device is being used, the date and time of any instances where visible emissions are observed from the device.

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XVII.H. (State Only) Venting during downhole well maintenance and unloading events

XVII.H.1. Well Maintenance: Beginning May 1, 2014, hydrocarbon emissions from flowing wells must be captured or controlled during downhole well maintenance or servicing activities, unless venting is necessary for safety.

XVII.H.1.a. Operators shall use best management practices to minimize the need for well venting associated with downhole well maintenance and liquids unloading. During liquids unloading events, any means of creating differential pressure will first be used to attempt to unload the liquids from the well without venting. If these methods are not successful in unloading the liquids from the well, the well may be vented to the atmosphere to create the necessary differential pressure to bring the liquids to the surface.

XVII.H.1.b. Venting will be minimized to the extent possible, using best management practices during the well maintenance and liquids unloading events in XVII.H.1.a. The owner and/or operator shall be present on-site during any planned well maintenance and liquids unloading event in XVII.H.1.a. and

shall ensure that any venting to the atmosphere is limited to the maximum extent practicable.

XVII.H.1.c. Records of the cause, date, time, and duration of venting events under this Section XVII.H. will be kept and made available to the Division upon request.

XVIII. (State Only) Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations

XVIII.A. Applicability

This section applies to pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations, natural gas compressor stations, and/or natural gas drip stations).

XVIII.B. Definitions

- XVIII.B.1. "Affected Operations" shall mean pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations, natural gas compressor stations, and/or natural gas drip stations).
- XVIII.B.2. "Enhanced Maintenance" is specific to high-bleed devices and shall include but is not limited to cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; and eliminating unnecessary valve positioners.
- XVIII.B.3. "High-Bleed Pneumatic Controller" shall mean a pneumatic controller that is designed to have a constant bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.
- XVIII.B.4. "Low-Bleed Pneumatic controller" shall mean a pneumatic controller that is designed to have a constant bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.
- XVIII.B.5. "Natural Gas Processing Plant" shall mean any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.
- XVIII.B.6. "No-bleed Pneumatic Controller" shall mean any pneumatic controller that is not using hydrocarbon gas as the valve's actuating gas.
- XVIII.B.7. "Pneumatic Controller" shall mean an instrument that is actuated using natural gas pressure and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow and temperature.

XVIII.C. Emission Reduction Requirements

The owners and operators of affected operations shall reduce emissions of volatile organic compounds from pneumatic controllers associated with affected operations as follows:

XVIII.C.1. In the 8-Hour Ozone Control Area:

XVIII.C.1.a. All pneumatic controllers placed in service on or after February 1, 2009, shall emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.1.c.

XVIII.C.1.b. All high-bleed pneumatic controllers in service prior to February 1, 2009 shall be replaced or retrofit such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, by May 1, 2009, unless allowed pursuant to Section XVIII.C.1.c.

XVIII.C.1.c. All high-bleed pneumatic controllers that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.1.c.(i) For high-bleed pneumatic controllers in service prior to February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and /or process purposes by March 1, 2009. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.1.c.(ii) For high-bleed pneumatic controllers placed in service on or after February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and /or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.2. Statewide:

XVIII.C.2.a. All pneumatic controllers placed in service on or after May 1, 2014, shall:

XVIII.C.2.c.(i) Emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.; or

XVIII.C.2.c.(ii) Utilize no-bleed pneumatic controllers where on-site electrical grid power is being used and is technically and economically feasible.

XVIII.C.2.b. All high-bleed pneumatic controllers in service prior to May 1, 2014, shall be replaced or retrofitted by May 1, 2015, such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.

XVIII.C.2.c. All high-bleed controllers that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.2.c.(i) All high-bleed pneumatic controllers in service prior to May 1, 2014, the owner/operator shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and/or process purposes by March 1, 2015. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.2.c.(ii) For high-bleed pneumatic controllers placed in service on or after May 1, 2014, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and/or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.D. Monitoring

This section applies only to high-bleed pneumatic controllers identified in Sections XVIII.C.1.c. and XVIII.C.2.c.

XVIII.D.1. In the 8-Hour Ozone Control Area

XVIII.D.1.a. Effective May 1, 2009, each high-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.1.b. Effective May 1, 2009, each high-bleed pneumatic controller shall be inspected on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2, and maintain the device according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.D.2. Statewide:

XVIII.D.2.a. Effective May 1, 2015, each high-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed

pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.2.b. Effective May 1, 2015, each high-bleed pneumatic controller shall be inspected on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2 , and maintain the device according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.E. Recordkeeping

This section applies only to high-bleed pneumatic controllers identified in Sections XVIII.C.1.c. and XVIII.C.2.c.

XVIII.E.1. The owner or operator of affected operations shall maintain a log of the total number of high-bleed pneumatic controllers and their associated controller numbers per facility, the total number of high-bleed pneumatic controllers per company and the associated justification that the high-bleed pneumatic controllers must be used pursuant to Sections XVIII.C.1.c. and XVIII.C.2.c. The log shall be updated on a monthly basis.

XVIII.E.2. The owner or operator shall maintain a log of enhanced maintenance which shall include, at a minimum, inspection dates, the date of the maintenance activity, high-bleed pneumatic controller number, description of the maintenance performed, results and date of any corrective action taken, and the printed name and signature of the individual performing the maintenance. The log shall be updated on a monthly basis.

XVIII.E.3. Records of enhanced maintenance of pneumatic controllers shall be maintained for a minimum of three years and readily made available to the Division upon request.

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XIX. Statements of Basis, Specific Statutory Authority and Purpose

XIX.N. February 21, 2014 (Sections II., XVII., and XVIII.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's ("Commission") Procedural Rules.

Basis

The oil and gas industry is a source of volatile organic compounds ("VOCs"), an ozone precursor. Additionally, oil and gas operations are a source of other hydrocarbon emissions, such as methane, through the leaking and venting of natural gas.

On October 18, 2012, the Commission partially adopted federal Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution found in 40 C.F.R. Part 60, Subpart OOOO ("NSPS OOOO") into Regulation Number 6, Part A. During the partial adoption of NSPS OOOO, the Commission requested the Air Pollution Control Division ("Division") to consider full adoption at a later date and directed the Division to identify additional oil and gas control measures that complement and expand upon NSPS OOOO. This rulemaking is the result.

The Commission supports the EPA's development of NSPS OOOO, and believes that additional hydrocarbon control measures are warranted in Colorado for several reasons. The Denver Metropolitan Area/North Front Range is in nonattainment with EPA's current 8-Hour Ozone National Ambient Air Quality Standard ("NAAQS"). It is also likely that EPA will lower the ozone NAAQS in the near future. In addition, Colorado has seen significant growth of oil and gas development in recent years, and that growth is expected to continue in the foreseeable future. The oil and gas industry is a significant source of VOC emissions (an ozone precursor). This is particularly true of oil and gas storage tanks. Oil and gas operations also emit methane, a negligibly reactive ozone precursor and a potent greenhouse gas. Division air monitors and other sampling indicate elevated levels of oil and gas related compounds in oil and gas development areas. Improved technologies and business practices can reduce emissions of hydrocarbons such as VOCs and methane in a cost effective manner. Many Colorado operators are already utilizing such technologies and practices to some degree including, without limitation, auto-igniters, low- or no-bleed pneumatic controllers, stabilized liquids or reduced tank pressures, flares achieving at least 98% destruction efficiency, and leak detection and repair (including the use of infrared ("IR") cameras). These technologies and practices have the added benefit of reducing several types of hydrocarbon emissions at the same time.

Colorado has vast experience with the regulation of oil and gas sources. In 2004, 2006, and 2008, the Commission established oil and gas industry emissions controls in Regulation Number 7, Sections XII., XVII., and XVIII. In March 2004, the Commission required condensate tank, controlled under the system-wide approach in what was known as the 8-Hour Ozone Control Area, to meet a 95% control efficiency requirement. This provision was approved into the State Implementation Plan ("SIP"). In December 2006, the Commission determined that on a state-wide, state-only basis, all (new and existing) condensate storage tanks must install air pollution control equipment and meet 95% destruction of VOC, if the total VOC emissions from the tank were equal to or greater than twenty (20) tons per year ("tpy"). Due to "flash," operators have had difficulty consistently meeting this 95% control requirement.

For these reasons and more, the Commission believes additional control measures beyond the current requirements in Regulation Number 7 and NSPS OOOO are appropriate. These regulations apply on a state-wide, state-only basis, and are not a part of Colorado's SIP. This approach gives the Commission, the Division, and stakeholders the opportunity to further assess the implementation and effectiveness of these requirements, to better inform future actions.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., (“Act”), C.R.S. § 25-7-105(1) directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in Section 25-7-102 and are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant and provides the Commission broad authority to regulate air pollutants. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Section 109(1)(a), (2), and (3) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides broad authority to regulate hydrocarbons.

Purpose

The Commission adopts revisions throughout Regulation Number 7 to address hydrocarbon emissions from oil and gas facilities, including well production facilities and compressor stations. The revisions expand existing oil and gas control requirements and establish additional monitoring, recordkeeping, and reporting requirements. For example, regarding oil and gas storage tanks, the revisions increase control requirements and improve capture efficiency requirements. The Commission also seeks to minimize fugitive emissions from leaking components at compressor stations and well production facilities. Further, the Commission intends to minimize emissions at new and modified oil and gas wells, and wells undergoing maintenance. The Commission also expands control requirements for pneumatic devices and glycol dehydrators. The Commission believes that this combination of revisions is appropriate to fully adopt NSPS OOOO, and to further reduce emissions produced by the oil and gas industry.

Among other things, these revisions:

- Expressly address hydrocarbon emissions in Section XVII. and XVIII.;
- Amend definitions in Section XVII.A. and XVIII.B.;
- Strengthen good air pollution control practices, require use of auto-igniters, and remove the off-ramp for condensate tanks if subject to NSPS, MACT, or BACT in Section XVII.B.;
- Expand condensate tank control requirements to apply state-wide, to all hydrocarbon liquid storage tanks, and to smaller storage tanks in Section XVII.C.;

- Limit venting and establish a storage tank emissions monitoring system (“STEM”), and associated recordkeeping and reporting requirements in Section XVII.C.;
- Expand glycol dehydrator control requirements in Section XVII.D.;
- Establish a leak detection and repair program for compressor stations and well production facilities in Section XVII.F.;
- Establish control measures for oil and gas wells in Section XVII.G.;
- Limit venting during well maintenance in Section XVII.H.; and
- Expand pneumatic device requirements in Section XVII.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The Commission intends that all the revisions to Regulation Number 7, are state-only requirements.

The following explanations provide further insight into the Commission’s intention for certain revisions.

Joint Applicability of NSPS OOOO and Regulation Number 7 Sections XII. and XVII.

It is possible for storage tanks to be subject to NSPS OOOO and Regulation Number 7, Sections XII. and XVII. While this creates an overlap between the different requirements, the requirements secure different emissions reductions. Regulation Number 7, Section XII. applies to condensate storage tanks in the 8-Hour Ozone Nonattainment Area, whereas NSPS OOOO applies to storage vessels that contain more than just condensate, such as produced water and crude oil storage vessels. NSPS OOOO also applies to individual storage vessels, whereas Regulation Number 7, Sections XII. and XVII. apply to single tanks and, if manifolded together, the series of tanks in tank batteries. In addition, NSPS OOOO applies to storage vessels with 6 tpy of controlled actual VOC emissions, whereas Regulation Number 7, Sections XII. and XVII. base applicability on uncontrolled actual emissions. For these reasons, and considering that portions of Regulation Number 7, Section XII. are approved in Colorado’s SIP, the Commission intends for the federal and state rules to jointly apply to storage tanks in Colorado. Thus, the Commission intentionally removed storage tanks from the exemption in Section XVII.B.4. that allowed sources subject to an NSPS, MACT, or BACT requirement to avoid having to comply with overlapping requirements in Section XVII.

Furthermore, because NSPS OOOO allows oil and gas operators to avoid applicability by establishing enforceable emission limits below NSPS OOOO applicability thresholds through a state, federal, or local requirement, most storage tanks subject to Regulation Number 7 will not be subject to NSPS OOOO monitoring or recordkeeping requirements. In those limited cases where storage tanks are subject to

both NSPS OOOO and current Regulation Number 7 control requirements, Regulation Number 7 will require some additional emissions monitoring.

However, joint applicability is anticipated to be limited to those storage tanks whose uncontrolled actual VOC emissions are one hundred and twenty (120) tpy (the equivalent of six (6) tpy VOC on a controlled actual basis). While this means that more storage tanks are regulated under Regulation Number 7, Section XVII., they are regulated on a state-only basis, and are not federally enforceable like NSPS OOOO. Thus, the Commission believes joint applicability is necessary.

It is the Commission's intent that compliance with Sections XII. and XVII. shall serve to establish legally and practically enforceable limits for the purpose of estimating emissions.

Applicability of Parts of Regulation Number 7 to Hydrocarbons

Many of the control measures set forth in these revisions have the benefit of reducing both VOC emissions and emissions of other hydrocarbons such as methane. Sections XVII. and XVIII. have been revised to reflect the Commission's intent that the provisions contained therein reduce emissions of the broader category of hydrocarbons.

Visible Emissions

Regulation Number 7, Sections XII. and XVII. have historically contained a prohibition on visible emissions from combustion devices, such as flares. The Commission is not proposing to relax this requirement. To address comments from diverse stakeholders, the Commission is clarifying how the Division inspectors and the regulated community are to determine compliance with the prohibition on visible emissions going forward. The Commission has qualified that visible emissions are emissions of smoke that are observed for a period in duration of one (1) minute during a fifteen (15) minute time period. The Commission expects that both Division inspectors and the regulated community will, if any smoke is observed, determine whether the emissions are considered visible emissions for purposes of Regulation Number 7.

Definitions (Section XVII.A.)

The Commission has revised or added definitions for several terms. Further explanation for a few of these terms is set forth below.

"Normal operation" is considered to include all operation, including maintenance and other activities, as long as the operation does not meet the definition of "malfunction" as set forth in the Common Provision regulations.

"Date of first production" is meant to coincide with the date reported to the Colorado Oil and Gas Conservation Commission's ("COGCC") as the "date of first production," as currently used in COGCC Form 5A. The Commission intends for oil and gas sources to use only one date for compliance with both the COGCC and Commission requirements.

“Storage tank,” means a single tank, as well as a tank battery if the tanks are manifolded together. In recent years, it has become more common for multiple tank batteries, sometimes containing different hydrocarbon liquids, to be manifolded at the emissions line and routed to a common control device. To further clarify the concept of manifolded within the definition of “storage tank,” the Commission revises the definition of storage tank to specify that a tank battery must be manifolded by liquid line, and not just be gas or emission line. This revision is in keeping with the rationale that a single tank could have been used to capture liquids in place of multiple small tanks in a battery. The Commission’s definition differs from EPA’s definition of “storage vessel” and the description of an affected storage vessel facility in NSPS OOOO. EPA considers each individual tank, even those in a battery manifolded by liquid line, to be a storage vessel for comparison against the applicability threshold. However, this approach differs from how Colorado has required emissions reporting and permitting for storage tanks, and the Commission intends to maintain that distinction. The Commission, therefore, deletes the previously used definition of “atmospheric condensate storage tank” and creates a new definition of “storage tank” which expands upon the definition of storage vessel in NSPS OOOO to include storage vessels manifolded together by liquid line.

“Well production facilities” are subject to leak detection and maintenance requirements. This definition is meant to include all of the emission points, as well as any other equipment and associated piping and components, located at the same stationary source (a defined term specific to permitting).

Good Air Pollution Control Practices (Section XVII.B.)

The Commission intends that all oil and gas sources, including those below the control threshold or even below Regulation Number 3 APEN and permitting thresholds, be required to adhere to good general air pollution control practices. Examples of what the Commission considers to be a good air pollution control practice include, but are not limited to:

- Keeping the thief hatch, pressure relief valve, or other access point on storage tanks closed and properly sealed during normal operation, unless being actively used during periods of maintenance or liquids loadout from the storage tank;
- Inspecting and repairing seals on their hatches, access points, or other openings of storage tanks;
- Initiating timely action to address leaks or unpermitted emissions; and
- Maintaining equipment and facility in good operating condition.

Controls for Storage Tanks Over 6 tpy (Section XVII.C.)

EPA established a six (6) tpy VOC threshold for applying storage vessel controls. This threshold differs from Regulation Number 7, Section XVII. in that it applies to individual tanks on a controlled actual emissions basis. In contrast, Colorado uses the sum total emissions from a tank battery, where multiple tanks are manifolded together, on an uncontrolled actual emissions basis for reporting, permitting, and

control requirements. This means that the EPA's six (6) tpy threshold on a controlled actual emissions basis applies to individual tanks having the equivalent of one hundred and twenty (120) tpy VOC on an uncontrolled actual basis. Thus, more storage tanks are regulated under Regulation Number 7, Section XVII. than under NSPS OOOO.

The Commission intends that under Regulation Number 7, Section XVII., air pollution control devices can be removed if the following conditions are met: (1) storage tank (including manifolded tanks) emissions are below the uncontrolled actual six (6) tpy threshold, on a rolling twelve month basis and (2) controls are not required by other applicable requirements. Conversely, if storage tank emissions increase above the six (6) tpy threshold, control equipment must be installed within sixty (60) days of discovery of the increase.

Control Efficiency (Section XVII.C.)

The Commission expands the 95% control efficiency requirement to apply to storage tanks containing any hydrocarbon liquids (including condensate, crude oil, produced water, and intermediate hydrocarbon liquids), for consistency with NSPS OOOO. Produced water and crude oil storage tanks, which in years past were thought to have insignificant emissions, can instead be significant sources of emissions. This rule change is also a result, in part, of the removal of the APEN exemption in 2008 for tanks containing crude oil and less than 1% crude. The Commission intends that the air pollution control equipment achieve an average hydrocarbon control efficiency of at least 95%, and if a combustion device is used, it must have a design destruction efficiency of at least 98%. The Commission recognizes and expects that most flares can control hydrocarbon emissions by 98% or more than properly operated.

Venting vs. Leaking (Sections XVII.B., XVII.C., and XVII.F.)

The Commission believes that emissions caused by over pressurization of oil and gas equipment are foreseeable, are not adequately addressed by NSPS OOOO, and should be addressed in Colorado specific regulations. Venting includes emissions from equipment such as a storage tank at the thief hatch, pressure relief valve, or other access point. Access points are not limited to points of entry of liquids or gas into the storage tank, but include any route from which emissions can escape. However, there are limited circumstances which should not be considered venting, such as where storage tanks emit in emergency situations, during maintenance, gauging, or where necessary to ensure the safety of personnel and equipment. For example, an unplanned third party outage resulting in increased pressure along the system may be the type of malfunction or scenario where venting may be necessary for safety purposes. Inadequate design of a storage tank emissions capture system is not a legitimate reason for venting. The Commission intends that the burden remain on the owner/operator to demonstrate that an emission should not be considered venting as provided in Section XVII.C.2.

The Commission further intends that the malfunction affirmative defense in the Common Provisions regulation continue to be available to operators, provided that the operators demonstrate that the elements of the malfunction affirmative defense have been met. The Commission recognizes that pressure release valves and other devices are meant to operate as safety devices, and not as emission

devices. Nothing in this revision is intended to increase risk or compromise safety of personnel and equipment. The Commission recognizes that venting for safety purposes may occur due to sudden, unavoidable equipment failures or surges beyond normal or usual activities that could not have been reasonably foreseeable, avoided, or planned.

In contrast with venting, leaking as used in Section XVII.F. more specifically relates to unintended emissions from components at well production facilities and compressor stations. Identification and repair of leaks in accordance with these revisions benefits the public, the environment, and the oil and gas industry. The Commission has determined that leaks discovered pursuant to the detection methods specified in Section XVII.F. shall not be subject to enforcement by the Division under certain circumstances. For example, if an operator has identified a leak and is in the process of timely and properly addressing the leak in accordance with these revisions, the Division should afford the operator the opportunity to fix the leak absent enforcement. However, by this provision, the Commission does not intend to exempt owners and operators from their obligation to operate without venting or to utilize good air pollution control practices at all times.

Storage Tank Emission Management System (STEM) Plan, Monitoring, and Recordkeeping (Section XVII.C.)

All owners and operators of any storage tank not containing only stabilized liquid must develop, certify, and implement a STEM plan designed, in part, to ensure compliance with the “without venting” requirement of Section XVII.C., among other requirements. Through STEM, owners and operators must evaluate and employ appropriate control technologies and monitoring, maintenance, and operational practices, to avoid venting of emissions from storage tanks. The Commission intends that sources have flexibility in the development of individualized STEM plans. STEM plans may be developed on an individual basis for each storage tank or may be developed for a swath of similarly designed or sized tanks. However, upon request, the owner or operator must be able to identify to the Division what STEM plan applies to a storage tank and make that plan available for review.

Owners and operators of storage tanks containing only stabilized liquids are not required to develop and implement a STEM plan. However, these tanks must still comply with applicable control, capture, monitoring, and recordkeeping requirements.

For purposes of clarification, the STEM plan is intended to include the following elements:

- A monitoring strategy with a minimum of the applicable inspection frequency and methodology;
- An identification of the personnel conducting the monitoring, and any training program, materials, or training schedule for such personnel. This element does not require training, but ensures that any training be documented to permit the operator to demonstrate the quality and achievements of its STEM plan;

- The calibration methodology and schedule for emission detection equipment used in the monitoring;
- An analysis of the engineering design of the storage tank and air pollution control equipment, and where applicable, the technological or operational methods employed to preventing venting;
- An identification of the procedures to be employed to evaluate ongoing capture performance after implementation of the STEM plan;
- A procedures to update the STEM plan when capture performance is not adequate, the STEM design is not operating properly, when otherwise desired by the owner or operator, or when required by the Division; and
- The certification made by the appropriate personnel with actual knowledge of the STEM design for each storage tank.

Monitoring for storage tanks must be conducted utilizing an Approved Instrument Based Monitoring Method, on a frequency schedule that is tied to an emissions from the tank. In addition to any applicable Approve Instrument Based Monitoring Method, the Commission intends that all owners or operators of a storage tank (whether or not it contains stabilized liquids) conduct applicable audio, visual, olfactory (“AVO”) monitoring. AVO inspection is not required to occur at the same time as loadout. Instead, loadout triggers the requirement for AVO inspection, and indicates the frequency with which AVO inspection is required.

Documentation of the STEM plan should be maintained by the owner or operator for the life of the storage tank, while records of STEM monitoring only need to be retained for a period of two years. Upon sale or transfer of ownership of a storage tank, the relevant documentation and records should be transferred with the ownership. Owners and operators are encouraged to reevaluate any existing STEM plan for the storage tank upon purchase or acquisition of the storage tank.

Glycol dehydrators (Section XVII.D.)

The Commission expanded the state-wide control requirements for glycol natural gas dehydrators. Currently, any glycol natural gas dehydrator with uncontrolled actual VOC emissions of two tons per year or greater that is located at a facility where the sum of uncontrolled actual VOC emissions from all of the dehydrators at the facility is greater than fifteen tpy must be equipped with a control device that reduces emissions by at least 90%. This revision requires that all existing dehydrators with uncontrolled actual emissions of six (6) tpy or greater VOC must be controlled with air pollution control equipment achieving at least 95% reduction. This revision also provides that existing dehydrator with uncontrolled actual emissions of two (2) tpy or greater VOC must be controlled if they are located within 1,320 feet of a building unit or designated outside activity area. The definitions for building unit and designated outside activity area are taken from COGCC regulations. Finally, this revision requires that all new dehydrators with uncontrolled actual emissions of two (2) tpy or greater VOC must be controlled. The

Commission intends that the air pollution control equipment achieves an average hydrocarbon control efficiency of at least 95%, and if a combustion device is used, it must have a design destruction efficiency of at least 98%. The Commission recognizes and expects that most flares can control hydrocarbon emissions by 98% or more when properly operated.

Leak Detection and Repair Requirements (Section XVII.F.)

The Commission believes the detection and timely repair of leaks is important in the efforts to reduce hydrocarbon emissions. The use of appropriate inspection instruments and methods, such as IR cameras, enhances the detection and reduction of emissions. STEM targets venting from storage tanks, while the detection and repair program more broadly targets leaks from components at compressor stations and well production facilities, even if they do not include storage tanks. The use of an Approved Instrument Based Monitoring Method as it relates to leak detection and repair frequency is generally intended to complement the STEM monitoring schedule. The Commission has created a phased schedule and tiered approach for leak detection and repair that is based on emissions, recognizing that smaller operators and facilities may need or want additional time to comply and may have lower emissions. Owner and operators have flexibility in how to meet the leak detection and repair requirements, including utilizing their own equipment and personnel or hiring a third party contractor.

The Commission has defined a leak in a manner that is dependent on the monitoring methodology used in detection. Leak detection methodologies have varied abilities to identify emission quantity and chemical makeup. EPA Reference Method 21, for example, detects and quantifies hydrocarbon emission concentration, but does not speciate hydrocarbons (e.g., methane from other hydrocarbons) or identifies the emission rate. IR cameras are becoming much more prevalent as a more affordable, time-saving, and user-friendly tool, but they also do not speciate hydrocarbons or quantify the emission concentration. The Commission provides owners and operators flexibility in choosing instrument based detection methodology.

If Method 21 is utilized, the Commission has set the threshold at which component leaks must be repaired at 2,000 parts per million ("ppm") hydrocarbons for existing compressor stations and 500 ppm for new (constructed after May 1, 2014) compressor stations and new and existing well production facilities. Where IR camera or AVO monitoring is used, a leak is any detectable emission not associated with normal equipment operation. These values were determined based in part on a review of current federal or state leak detection and repair requirements for natural gas processing plants, refineries, and other oil and gas sources. Leak detection values have decreased over time, in recognition of improved technologies and business practices. NSPS OOOO establishes leak detection at natural gas processing component type. Prior to NSPS OOOO, leaks were identified in other New Source Performance Standards (NSPS KKK and NSPS VVa) at 10,000 ppm. In addition, California, Wyoming, and Pennsylvania have varying leak detection and repair requirements and approaches to defining a leak. Some California air quality districts generally define a minor leak as between 1,000 and 10,000 ppm. Wyoming does not have a numerical limit. Pennsylvania essentially defines a leak at a well pad as anything with detectable emissions utilizing Method 21, as more than 2.5% methane or 500 ppm VOC, or no visible leaks using an

IR camera. Upon consideration of all of the evidence presented, the Commission chose to define component leak at the foregoing thresholds.

The Commission anticipates that many operators will choose to utilize IR cameras, in light of their relative ease of use and increased reliance by both by industry and regulators within Colorado and across the country. The Commission expects that leaks that are not located specifically at a component will be addressed and repaired, in accordance with the general requirements to minimize emissions and employ good air pollution control practices.

The Commission expects that in most instances the leak detection and repair requirements of this regulation will apply in lieu of leak detection and repair requirements in existing permits. The Commission recognizes that leak detection and repair requirements in a few state permits may be federally enforceable, and this state-only regulation cannot supersede federal requirements. The Commission expects the Division and operators to work cooperatively on the efficient implementation of leak detection and repair requirements, in those rare instances where there may be duplicative or competing requirements.

Well Maintenance and Unloading (Section XVII.H.)

Over time, liquids build up inside a well and reduce flow out of the well. These liquids can slow and even block gas flow in wet gas wells and are removed during a well blowdown, also called liquids unloading. As a result of recent information, EPA has significantly increased their emission factor for liquids unloading. The uncontrolled emission factor is based upon fluid equilibrium calculations used to estimate the amount of gas needed to blow down a column of fluids blocking a well and Natural Gas STAR partner data on the amount of additional venting after a blowdown. Similar to the issues with well completion emissions, considerable uncertainty for liquid unloading emissions arises from the limited data sources used and the applicability of Natural Gas STAR program activities to calculate industry baseline emissions. This is especially important as liquid unloading is estimated to comprise 33% of the uncontrolled methane emissions from the natural gas industry in the latest greenhouse gas inventory. EPA's Natural Gas STAR program advocates the use of a plunger lift system to reduce the need for liquids unloading, and indicates that such systems may pay for themselves in about one year. The Commission has determined that the use of technologies and practices to minimize venting, including plunger lift systems, are available and economically feasible, and encourages their use in Colorado.

Pneumatic Controllers (Section XVIII.)

The Commission recognized in a December 2008 rulemaking that pneumatic devices are a significant source of emissions. In addition, a 2013 University of Texas study concluded that methane emissions from pneumatics are higher than EPA previously estimated. Therefore, expanding the current low-bleed pneumatic device requirements statewide and further reducing emissions is appropriate and cost-effective. While the use of low-bleed pneumatics will result in a significant reduction of VOC and methane emissions from Colorado oil and gas facilities, no-bleed pneumatic controllers are currently commercially available to further reduce emissions from these sources. However, because these devices can only be used at facilities with adequate electric power, and given the high cost of electrifying

a facility, the Commission is requiring the use of no-bleed pneumatics at facilities that are connected to the electric grid and using electricity to power equipment, but only where technically and economically feasible.

ADDITIONAL CONSIDERATIONS

In accordance with C.R.S. §§ 25-7-105.1 and 25-7-133(3) the Commission states the rules in Section XVII. and XVIII. of Regulation Number 7 adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to be incorporated into Colorado's SIP at this time.

In accordance with C.R.S. § 25-7-110.5(5)(b), the Commission determines:

- I. The revisions to Regulation Number 7 address hydrocarbon emissions from oil and gas facilities, including well production facilities and compressor stations. The majority of sources subject to the revised rules will not also be subject to NSPS OOOO or other federal law for such emissions. One goal of the revisions is to address individual sources below NSPS OOOO thresholds, yet that collectively contribute significantly to ozone formation in Colorado. Additionally, it is the Commission's determination that the venting of emissions from storage tanks at oil and gas facilities, caused primarily by over pressurization, is not adequately addressed under NSPS OOOO and therefore warrants Colorado-specific regulations. Moreover, leaks or fugitive emissions of hydrocarbons, such as VOCs and methane, particularly from well production facilities and compressor stations, are not adequately addressed under NSPS OOOO. Thus, Colorado specific regulations are appropriate. Finally, some very large sources (e.g. storage vessels emitting 120 tpy uncontrolled VOC) will be subject to both the revised rules and NSPS OOOO, including the reporting and monitoring requirements.

In addition to NSPS OOOO, several other federal NSPS, as well as National Emission Standards for Hazardous Air Pollutants ("NESHAP") that apply Maximum Achievable Control Technologies ("MACT") may apply to the tanks, dehydrators, leaking components, and pneumatic devices at oil and gas facilities subject to these revisions. These include, but are not limited to, NSPS Kb and NSPS KKK (which incorporate NSPS VV or VVa) and NESHAP HH and HHH. However, the Regulation Number 7 revisions apply on a broader basis to more tanks, dehydrators, leaking components, and pneumatic devices, and address more hydrocarbon emissions. Some examples include: tank and dehydrator control measures that apply at lower thresholds; leak detection and repair requirements applicable to components beyond gas processing plants; and pneumatic device provisions that require the use of lower emitting devices.

- II. NSPS OOOO is primarily technology-based in that it largely prescribes the use of specific technologies in order to comply. EPA has provided some flexibility by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold (greater than or equal to 6 tpy controlled actual VOCs). The

Commission chose to set the revised Regulation Number 7 controls at 6 tpy on an uncontrolled actual emissions basis, and therefore provide Colorado's oil and gas operators a limit for calculating the controlled PTE of their storage vessels, which may be used to avoid NSPS OOOO applicability.

- III. There are no federal requirements related to the revisions to Regulation Number 7 that specifically and fully address the issues of concern to Colorado, or take into account concerns that are unique to Colorado. NSPS OOOO addresses VOC emissions and certain co-benefits of reducing such emissions, but does not address hydrocarbon emissions in the more comprehensive manner addressed by these revisions. Following these revisions, Regulation Number 7 will surpass federal requirements in several ways, including, without limitation: (a) Regulation Number 7 will apply to a broader class of tanks than NSPS OOOO; (b) Regulation Number 7 will require a leak detection and repair program for more categories and components than NSPS OOOO; and (c) Regulation Number 7 will require storage tanks with uncontrolled actual emissions equal to or greater than 6 tpy VOC to control emissions with 95% efficiency, while NSPS OOOO's threshold is 6 tpy controlled actual emissions (i.e. 120 tpy uncontrolled actual emissions). It is the Commission's determination that, given the current and projected levels of oil and gas development in Colorado, combined with the advances in technology and business practices utilized by oil and gas operators, the revisions to Regulation Number 7 are appropriate to address hydrocarbon emissions from this sector. Such emission reductions will, among other things, protect public health and the environment, address current and future ozone concerns specific to Colorado, reduce greenhouse gas emissions, and ensure the maximum beneficial use of a valuable natural resource.
- IV. Compliance with the control requirements in the revisions to Regulation Number 7 provide Colorado's oil and gas operators a limit for calculating the controlled potential to emit of their storage vessels, thereby allowing many of these sources to avoid regulation under NSPS OOOO. Additionally, the revisions may prevent or reduce the need for more costly retrofits at a later date. The Denver Metro/North Front Range area is currently in nonattainment with the ozone NAAQS. Other areas in the State are seeing elevated ozone levels, including areas of increasing oil and gas development. Colorado may also be required to comply with a future ozone NAAQS that is lower than the current standard. The revised rules are intended to reduce ozone levels now by utilizing controls and techniques already being used or readily available. Utilizing these controls and techniques may prevent the need for more costly retrofitting in the future by addressing ozone precursor emissions now and not waiting until after ozone levels have increased.
- V. Adoption at this time allows many of Colorado's oil and gas operators to utilize the controls established in the revisions to Regulation Number 7 to avoid being subject to

NSPS OOOO storage vessel requirements. Postponement of adoption would potentially subject these sources to compliance with NSPS OOOO and then compliance with State requirements once State controls become effective.

- VI. The revisions to Regulation Number 7 do not place limits on the growth of Colorado's oil and gas industry. Instead, the rules address hydrocarbon emissions from the sector to assure air quality is maintained while also allowing for continued growth of Colorado's oil and gas industry. Indeed, the oil and gas industry has already grown in Colorado while widely utilizing many of the technologies and practices set forth in these revisions.
- VII. The revisions to Regulation Number 7 establish reasonable equity for oil and gas facilities subject to these rules by providing the same standards for similarly situated sources. The revisions to Regulation Number 7 were proposed after a lengthy stakeholder process. Rules of general applicability have been developed along with tiered requirements and exclusions that tailor the rules to the regulated sources within the oil and gas sector.
- VIII. The oil and gas industry is a large anthropogenic stationary source of VOCs, a precursor pollutant to ozone. If the revisions to Regulation Number 7 are not adopted, other aspects of oil and gas operations or other sectors may be looked to for additional emission reductions.
- IX. The majority of sources subject to the revised rules in Regulation Number 7 will not be subject to federal procedural, reporting, or monitoring requirements. Those few sources subject to both NSPS OOOO and Regulation Number 7 will be required to comply with both regulations. The procedural, reporting, and monitoring requirements of Regulation Number 7, to the extent different than federal requirements, are necessary to achieve the Commission's goals while maintaining flexibility for the operators.
- X. Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand requirements already applicable in the 8-Hour Ozone Nonattainment Area state-wide, such as the auto-igniters and pneumatic devices. In addition, many oil and gas operators are already using the control devices and techniques intended to be used to comply with these revisions. The lead-in time provides operators time to install control devices and develop plans for compliance. Should unanticipated events occur, such as a lack of availability of control devices, the rules provide for Division approved extensions to compliance.
- XI. As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will contribute to the prevention of hydrocarbon emissions in a cost-effective manner. Significantly, the Commission expressly finds that the cost-effectiveness of the VOC emission reductions alone supports the revisions to Regulation Number 7. The

reductions of other hydrocarbon emissions such as methane add to the already cost-effective and appropriate emission reduction requirements.

- XII. Alternative rules requiring differing or additional controls for oil and gas facilities could also provide reductions in hydrocarbon emissions. The Commission could adopt some or all of these proposed revisions. However, the revisions to Regulation Number 7 were proposed after a lengthy stakeholder process and provide a balanced approach, reducing emissions from the oil and gas industry while allowing the sector to continue to play a critical role in Colorado's economy and the nation's energy independence. A no action alternative would very likely only delay future reductions in hydrocarbon emissions, including ozone precursors pollutants, necessary for attaining or maintaining the ozone NAAQS in Colorado.
- XIII. The Commission has taken into consideration any evidence submitted regarding the factors set forth in C.R.S. § 25-7-109(1)(b).

The incorporation by reference of NSPS OOOO in Regulation Number 6 does not affect the requirements of these revisions to Regulation Number 7. Instead, these revisions to Regulation Number 7 are designed and intended to address the differences and overlaps between NSPS OOOO and current state requirements, and to include additional emission control measures for oil and gas production and equipment. To the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, the Commission hereby makes the determination that:

- I. These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.
- II. Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of hydrocarbon emissions.
- III. Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.
- IV. The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.
- V. The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

LEAK DETECTION AND REPAIR (LDAR) INSPECTION PROGRAM - ESTIMATED TRAVEL, EQUIPMENT AND LABOR COSTS

1.0 INTRODUCTION

There is economic burden for oil and gas (O&G) companies in the State of Colorado to implement leak detection and repair (LDAR) programs for their Colorado O&G facilities. Recently, a proposed amendment to Regulation 7 of the Colorado Department of Public Health and Environment (CDPHE), Air Pollution and Control Division (APCD) air regulations would lower the volatile organic compound (VOC) emissions threshold for which LDAR would be required. For this task, Boulder County requested that Terracon analyze the estimated travel time, labor and equipment costs for three typical mid-size Colorado O&G companies with multiple well production facilities (with the potential to emit 6 to 12 tons of uncontrolled VOC emissions per year per facility) and assuming that the company would self-perform its LDAR inspection program with leased monitoring equipment.

Terracon's task was to prepare geographical information system (GIS) simulations to estimate O&G company travel times, labor and equipment costs to self-perform LDAR inspections for their well production facilities in Colorado. Three "mid-sized" O&G companies (2013 statewide gas production volumes of 1.2 to 42 million MCF of gas) in Colorado were evaluated. Production values were obtained from the Colorado Oil and Gas Conservation Commission (COGCC) online database.

2.0 MODELING APPROACH

The initial modeling approach was to evaluate one worst-case scenario where an O&G company would conduct LDAR inspections for its well production facilities in both "urban" and "rural" settings. For purposes of this model, an "urban" setting includes the Denver-Julesburg (DJ) Basin north of Denver, and a "rural" setting includes the Piceance or Paradox Basins on the western slope. Additionally, the modeling approach was intended to evaluate two O&G companies in "rural" settings. However, based on our review of the COGCC database, we were unable to identify companies with well production facilities in the 6 to 12 tons per year uncontrolled VOC emissions range in only "rural" areas. Therefore, the remaining two modeling approaches included two companies with 6 to 12 ton emission well production facilities in "urban" Colorado.

For these simulations, Terracon used ESRI's Network Analyst to compute a least-cost (least-time) path using ESRI's Detailed Streets Layer (2007) and well production facility locational information provided by CDPHE.

3.0 MODELING ASSUMPTIONS AND ATTRIBUTES

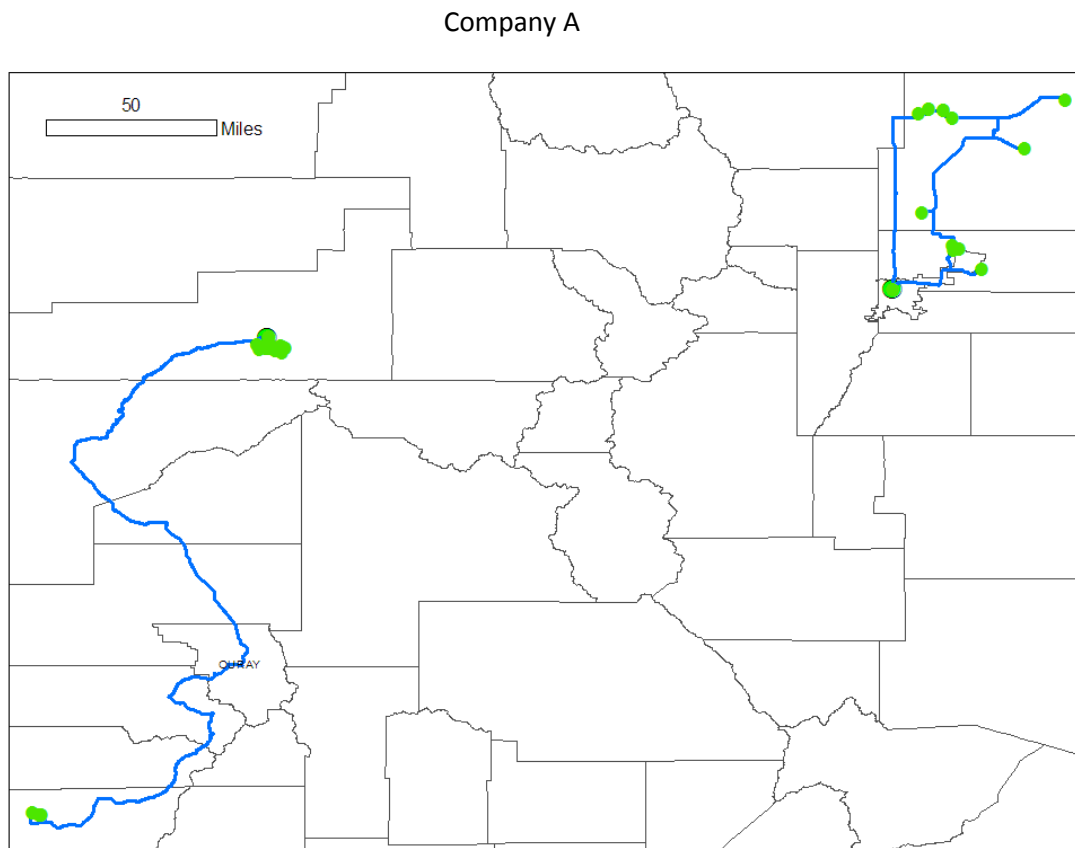
The following assumptions were made in preparing the following LDAR inspection travel time and cost estimates:

1. An LDAR inspection/monitoring loop consists of a round trip circuit to each well production facility containing equipment with uncontrolled VOC emissions ranging from 6 to 12 tons per year.
2. Each O&G operator self-performs the LDAR inspections using rented monitoring equipment, either a total vapor analyzer (TVA) or an infrared (IR) camera.
3. An average of three hours of monitoring time are required at each facility regardless of the instrument used. This time estimate is based on discussions with several LDAR vendors in Colorado.
4. One technician and one LDAR monitoring instrument is used
5. The ESRI 2007 street network is conservative for estimating distances between sites.
6. Although actual well production facility location information was provided by CDPHE, minor modifications to the latitude and/or longitude values were inputted into the GIS to preserve the anonymity of the O&G companies used for the GIS evaluation.

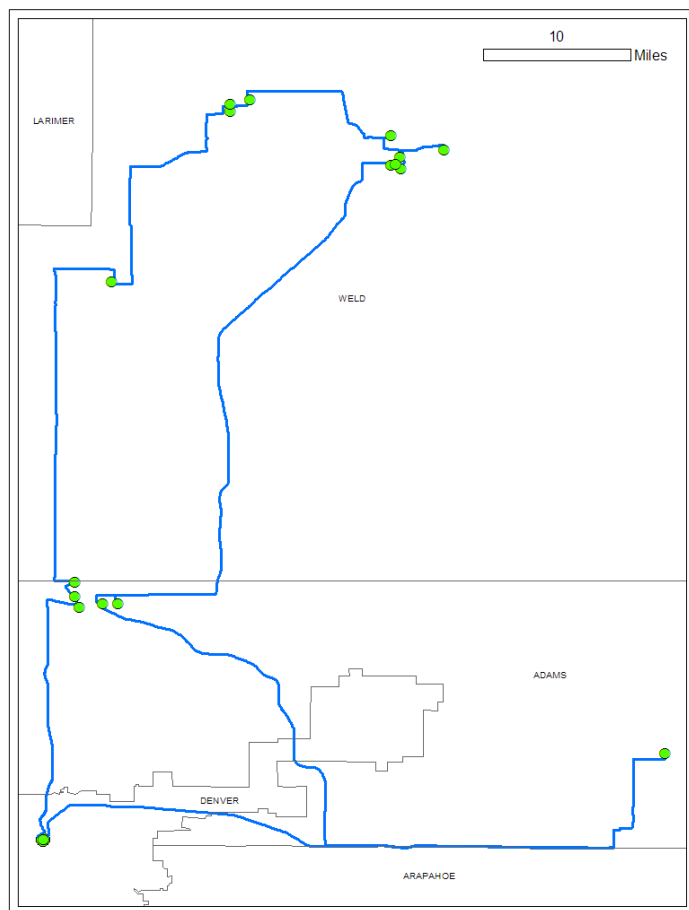
The following attributes were used to prepare ESRI's Detailed North America Street Map into a network dataset with least-cost routing capability.

Name	Usage	Units	Data Type
Length	Cost	Miles	Double
Oneway	Restriction	Unknown	Boolean
RoadClass	Descriptor	Unknown	Integer
Minutes	Cost	Minutes	Double
Hierarchy	Hierarchy	Unknown	Integer

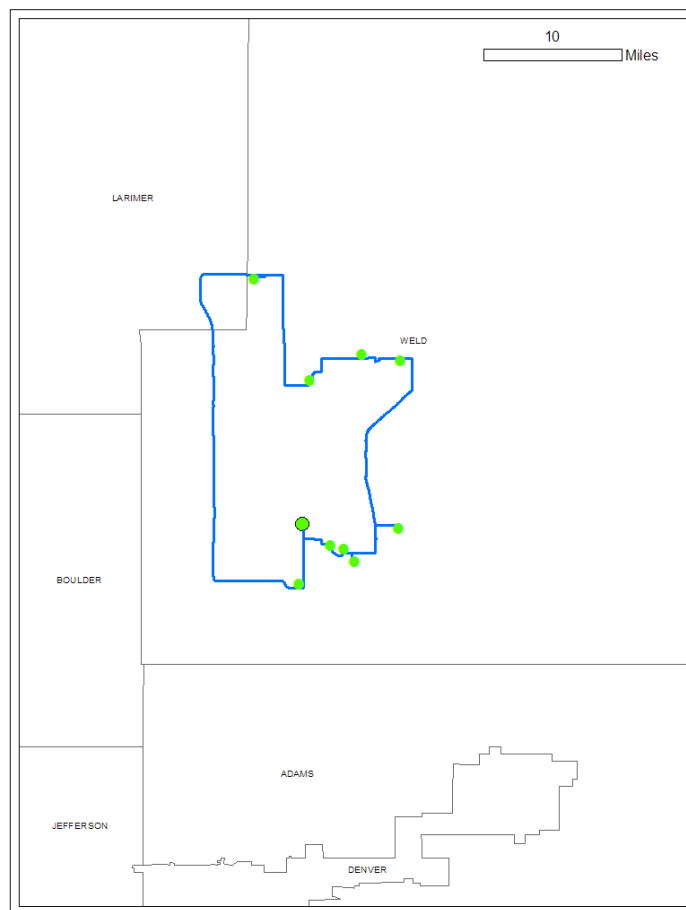
Figure 1 – Optimized Travel Routes for Companies A, B and C



Company B



Company C



Map Legend

1. Green points represent well production facilities with tanks or equipment with 6 - 12 tons per year in uncontrolled VOC emissions.
2. The Blue route lines between points represent the calculated shortest distance along the road network between every facility, starting and finishing at a point of origin.
3. Company A has two loops. One loop in the DJ Basin. The second loop in the Piceance and Paradox Basins with a starting point at an office in proximity to the Basin.
4. Companies B and C each have one loop with their starting points originating near Denver.

4.0 CALCULATION OF ESTIMATED LDAR INSPECTION PROGRAM LABOR AND EQUIPMENT COSTS

The total time to complete one LDAR monitoring loop includes the travel time between well production sites and the LDAR monitoring time at each site. The total labor cost, in dollars, is the total time to complete one LDAR monitoring loop times the monitoring technician's hourly rate. The total equipment cost is the total time to complete one LDAR monitoring loop times the daily rental rate for the monitoring equipment. Table 1 (see Attachment A) provides a summary of estimated labor and equipment costs for Companies A, B and C to complete one LDAR inspection and annual LDAR inspection costs assuming biannual inspections.

4.1 Method 21 – TVA 1000B Instrument

As indicated in Table 1 (Attachment A), one-time estimated LDAR inspection costs with a TVA 1000B instrument ranged from \$2,094 for Company C ("rural" setting) to \$8,891 for Company A ("rural" and "urban" setting). Annual LDAR inspection costs using a TVA 1000B instrument, assuming two inspections per year, ranged from \$4,188 for Company C ("rural" setting) to \$17,782 for Company A ("rural" and "urban" setting).

4.2 Method 21 – IR Camera

As indicated in Table 1 (Attachment A), one-time estimated LDAR inspection costs with an IR camera ranged from \$4,494 for Company C ("rural" setting) to \$18,491 for Company A ("rural" and "urban" setting). Annual LDAR inspection costs using an IR camera, assuming two inspections per year, ranged from \$8,988 for Company C ("rural" setting) to \$36,982 for Company A ("rural" and "urban" setting). Inspection times with an IR camera were assumed to be the same as a TVA 1000B (3 hours per site). Actual inspection times may be less using an IR camera, but are not quantified in this analysis.

4.3 Cost Exceptions

The estimated costs do not include the following:

1. LDAR program development costs
2. Method 21 certification or employee LDAR training
3. Purchase of leak detection Instruments
4. Preparation of LDAR reports for submittal to CDPHE
5. Repair or replacement of faulty equipment
6. Internal auditing
7. Per diem (meals and lodging) expenses
8. Supervisor and administrative support
9. Equipment calibration or accessories

5.0 CONCLUSIONS

Terracon used GIS simulations to estimate travel time and costs for three O&G companies to self-perform LDAR inspections for multiple well production facilities in Colorado. The analysis only included facilities with uncontrolled VOC emissions between 6 to 12 tons per year. Three companies were evaluated; one “rural and urban” company (Company A) with facilities in the DJ, Piceance and Paradox Basins and two “urban” companies (Companies B and C) with facilities only in the DJ Basin area.

One-time estimated LDAR inspection costs with a TVA 1000B instrument ranged from \$2,094 for Company C (“rural” setting) to \$8,891 for Company A (“rural” and “urban” setting). Annual LDAR inspection costs using a TVA 1000B instrument, assuming two inspections per year, ranged from \$4,188 for Company C (“rural” setting) to \$17,782 for Company A (“rural” and “urban” setting).

One-time estimated LDAR inspection costs with an IR camera ranged from \$4,494 for Company C (“rural” setting) to \$18,491 for Company A (“rural” and “urban” setting). Annual LDAR inspection costs using an IR camera, assuming two inspections per year, ranged from \$8,988 for Company C (“rural” setting) to \$36,982 for Company A (“rural” and “urban” setting).

6.0 QUALIFICATIONS AND LIMITATIONS

GIS simulations were developed to provide Boulder County with estimates of reasonable costs that may potentially be incurred by three mid-sized O&G companies to conduct LDAR inspections at Colorado well production facilities with tanks having uncontrolled VOC emissions ranging from 6 to 12 tons per year. This is an order-of-magnitude evaluation that provides the basis for more detailed cost evaluations. Our estimates are based on metropolitan and field office origination points, use of a least-time travel route, and average labor and equipment rates provided by LDAR inspection vendors. An actual LDAR inspection cost proposal could be obtained from a vendor provided that the number and locations of facilities and number of components at each facility are specified.

Terracon has endeavored to use a reasonable cost estimate approach to derive the conceptual LDAR inspection cost estimates given the stated assumptions. Potential inspection costs that were not evaluated or estimated are stated in our assumptions section of this report. In preparing this analysis, our scope was strictly limited to an evaluation of costs associated with travel, equipment and labor for LDAR inspections, and we are not providing opinions as to the cost burden for full implementation of the proposed amendments to Regulation 7 of the APCD CDPHE air regulations.

ATTACHMENT A

TABLE 1

DRAFT

Table 1: Estimated Labor and Equipment Costs for Three Colorado O&G Companies to Perform LDAR Inspections

O&G Company	Facilities ¹	Urban or Rural ²	Total Distance ³ (Miles)	Total Time (Hours) ^{4,5}	Cost per Inspection Event			Cost per Year (Assuming Biannual Inspections)		
					Travel and Inspection Cost ⁶	Travel and Inspection Cost using TVA 1000B ⁷	Travel and Inspection Cost using Infrared Camera ⁸	Travel and Inspection Cost ⁶	Travel and Inspection Cost using TVA 1000B ⁷	Travel and Inspection Cost using Infrared Camera ⁸
A (2 loops combined)	34	Urban and Rural	787	121	\$6,491	\$8,891	\$18,491	\$12,982	\$17,782	\$36,982
B	16	Urban	217	53	\$2,771	\$3,821	\$8,021	\$5,542	\$7,642	\$16,042
C	9	Urban	78	29	\$1,494	\$2,094	\$4,494	\$2,988	\$4,188	\$8,988

NOTES:

(See Figure 1 for route maps)

¹ Facilities with uncontrolled VOC emissions between 6 to 12 tons per year

² Location of facilities

³ Obtained from GIS Model

⁴ Total travel time from the GIS Model

⁵ Includes 3 hours per facility to complete LDAR inspection

⁶ Technician rate of \$ 50 per hour and \$0.56 per mile travelled

⁷ "TVA 1000B" analyzer cost is \$ 150.00 per day. Assume 8 hour days. Shipping costs are not included.

⁸ Infrared camera cost is \$ 750.00 per day. Assume 8 hour days. Shipping costs are not included.

OIL & GAS PRODUCTION FACILITIES POTENTIAL SOURCES OF FUGITIVE VOC EMISSIONS

Prepared for



WHERE CAN FUGITIVE VOC EMISSIONS OCCUR?

Fugitive VOC emissions can occur on various types of equipment and devices involved in the production, storage, and conveyance of oil and gas.



Well Heads



Valve seals
and joints

Compressor Engines



Seals, flanges
and joints

Process Equipment



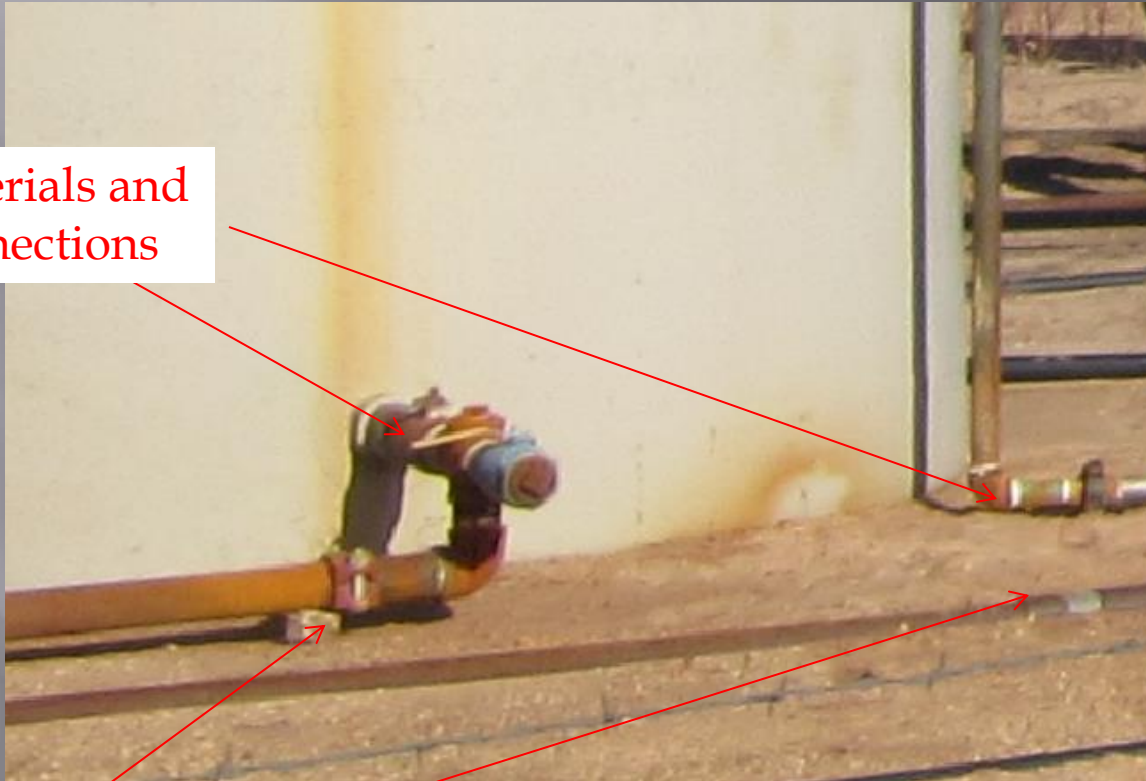
Flanges
and fittings

Tank Battery Site



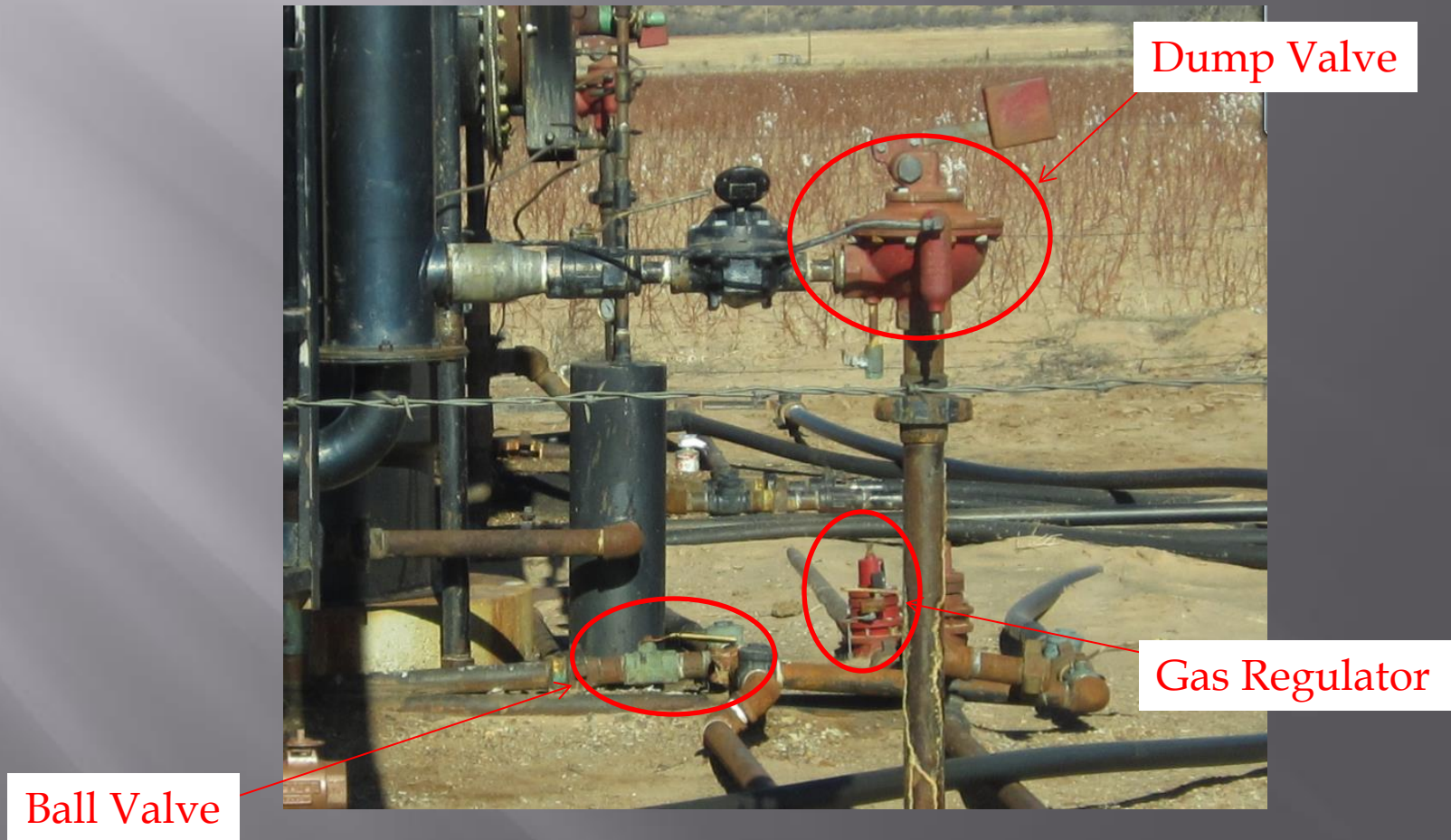
Tank Battery Site

Multiple materials and threaded connections



Inadequate support with threaded connections

Tank Battery Site

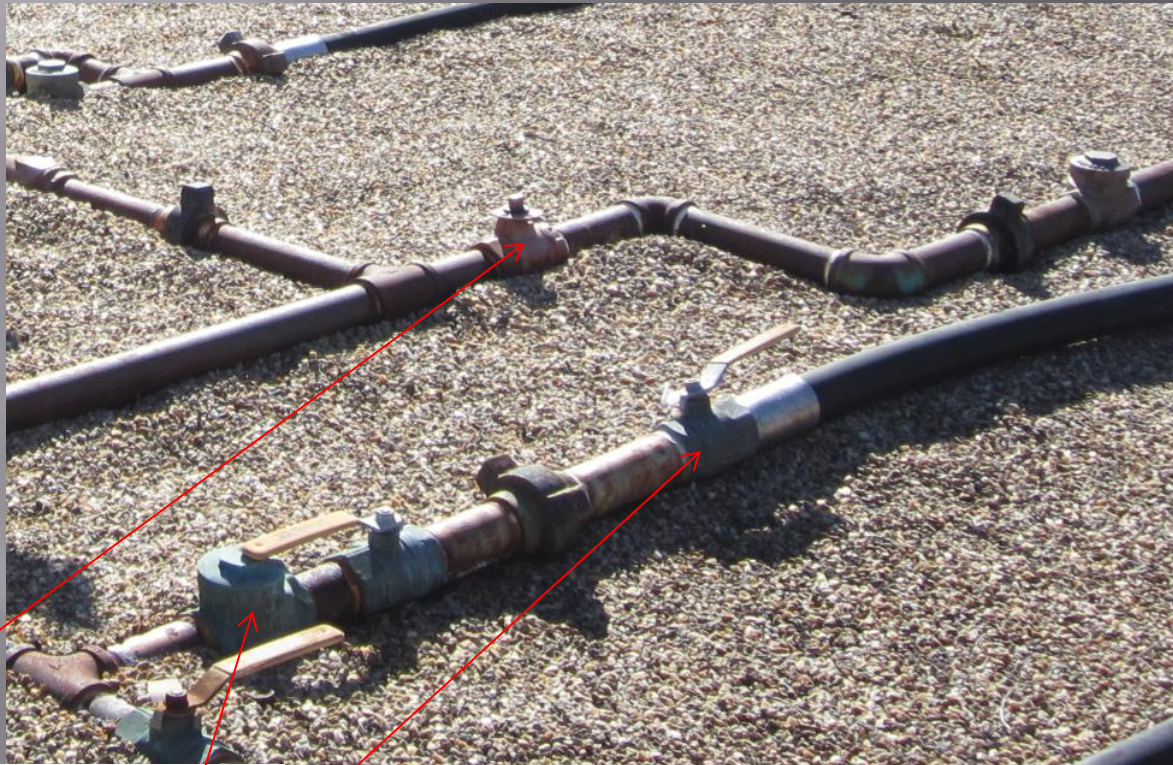


Tank Battery Site



Gas regulator with
threaded connections
and frozen ground
conditions

Tank Battery Site



Valves with
threaded connections

Tank Battery Site



Flanged connections

Tank Battery Site – Heater Treater



Fittings with
threaded connections

Tank Battery Site



Pneumatic
Controller

Tank Battery Site



Elbow fitting with
inadequate support

Tank Battery Site

(Unions, Couplings, Elbows and Valves)



What causes some leaks to occur?

- Threaded Connections:
 - Improper selection and/or application of thread tape can lead to material degradation or inability to create a seal. Thread tapes rated for greater than operating pressure and temperature should be chosen;
 - Inadequate support to pipes can lead to vibrations during pressure variations in the system, resulting in leaks; and
 - Connections near or under the ground in the presence of water may expand unevenly resulting in leaks.

Why do leaks occur? (cont..)

- ▣ Valves, Pressure Relief Valves (PRVs), Compressors, Pumps and Meters
 - Debris in the flow system can prevent the valve from completely closing allowing gas or oil to escape from the system downstream from the valve;
 - A damaged valve seat or seal;
 - Not performing scheduled re-greasing and/or equipment inspections per manufacturer recommendations; and
 - Lack or implementation of a regular operations and maintenance (O&M) program.

Why do leaks occur? (cont..)

- ▣ Inadequate O&M program may fail to identify:
 - Damage from impact;
 - Excessive corrosion;
 - Cracked seals;
 - Metal fatigue and stress cracks from hydrogen sulfide attack; and
 - Over-pressurization of storage vessel from inoperable PRV.

Potential Benefits of Implementing an LDAR Program*

- ▣ Reducing Product Losses,
- ▣ Decreasing exposure to surrounding community, and
- ▣ Potentially reducing emission fees

* Per EPA "Leak Detection and Repair-A Best Practices Guide"

LDAR SERVICE PROVIDERS

- ▣ <http://www.dexterfs.com>
- ▣ <http://www.enrud.com>
- ▣ <http://www.erm.com>
- ▣ <http://www.flir.com>
- ▣ <http://www.guardiancompliance.com>
- ▣ <http://www.heathus.com>
- ▣ <http://www.ldarsolutions.com>
- ▣ <http://www.ldartools.com>
- ▣ <http://www.inficon.com>
- ▣ <http://www.thermoscientific.com>
- ▣ <http://www.americanleakdetection.com>
- ▣ <http://customstackanalysis.com>
- ▣ <http://www.afcintl.com>
- ▣ <http://www.pesldar.com>
- ▣ <http://www.ldarsolutions.com>
- ▣ <http://www.iprems.com>
- ▣ <http://www.emsi-air.com/>
- ▣ <http://www.iprems.com/>
- ▣ <http://www.trihydro.com/>

LDAR SERVICE VENDORS OVERVIEW

Prepared for



VENDOR CONTACT & INFORMATION COLLECTION

- ▣ Several subcontractors contacted that provide LDAR monitoring services to the oil and gas industry in Colorado.
- ▣ The objective was to approximate costs charged for LDAR monitoring.
- ▣ Of the companies contacted, four companies provided responses.

TYPICAL LDAR SERVICES VENDOR COST BREAKDOWN

VENDORS ¹	LDAR TECHNICIAN HOURLY COST ²	LDAR SUPERVISOR HOURLY COST	EQUIPMENT CHARGES PER DAY ³	MILEAGE CHARGE PER MILE	NOTES
Vendor 1	\$ 35.00	\$ 45.00	Included for Method 21	Did not provide	---
Vendor 2	\$ 60.00	NA	\$ 200.00 (Equipment and vehicle charge)	Did not provide	---
Vendor 3	\$ 42.00	\$ 46.00	Included for Method 21	\$ 0.56	IR Camera - \$ 750.00 per day additional charge
Vendor 4 ⁴	\$ 48.00	\$ 65.00	Included for Method 21	\$ 1.00	IR Camera - \$ 750.00 per day additional charge

¹ Actual vendor names not provided as site specific information was not provided and to protect vendor competitive interests. Vendors have also indicated that pricing may vary based on site specific factors.

² Technician hourly cost does not include food/per diem expenses, overtime, hotel expenses or other travel expenses.

³ Method 21 does not specify an instrument detector type, but the detector used must satisfy the performance criteria specified in the method. The detector can use catalytic oxidation, flame ionization, infrared absorption, or photoionization. Vendors 1, 2 and 4 indicated that for LDAR inspection as per Method 21, there will be no additional equipment charges. However, if IR cameras are employed, there will be additional charges. Vendors may charge additional for tag sets, wires and cables.

⁴ Vendor 4 indicated that if only IR camera is used for leak detection then the LDAR technician hourly cost will be \$ 67.50 and Supervisor hourly cost will be \$ 90.00.

Notes from Vendor discussions

- ❑ IR cameras approved for Method 21 may not be readily available because of cost.
- ❑ Due to differences in training required for IR cameras, technician charges are usually higher.
- ❑ IR cameras approved for Method 21 are typically used to detect high concentrations or larger leaks and other Method 21 equipment is typically used for lower concentrations. Some vendors indicated that they could use a combination of Method 21 equipment and IR cameras based on the size of the site and number of potential fugitive emission sources.
- ❑ Most commonly used equipment for Method 21 is Thermo Toxic Vapor (TVA) Analyzer, TVA-1000B. As per research, rental cost for the equipment averages around \$ 150 per day, not including accessories or other miscellaneous parts/calibration kits.
- ❑ Most commonly used Infrared Camera was FLIR GasFindIR MW camera. As per research, rental cost for the camera averages around \$750 per day.

List of Vendors contacted

- <http://www.dexterfs.com>
- <http://www.enrud.com>
- <http://www.erm.com>
- <http://www.flir.com>
- <http://www.guardiancompliance.com>
- <http://www.heathus.com>
- <http://www.ldarsolutions.com>
- <http://www.ldartools.com>
- <http://www.inficon.com>
- <http://www.thermoscientific.com>
- <http://www.americanleakdetection.com>
- <http://customstackanalysis.com>
- <http://www.afcintl.com>
- <http://www.pesldar.com>
- <http://www.ldarsolutions.com>
- <http://www.iprems.com>
- <http://www.emsi-air.com/>
- <http://www.iprems.com/>
- <http://www.trihydro.com/>

Not all vendors responded to requests.

The next worksheet is the final EIA for the 6-12 TPY well production facility (WPF) changes that the LGC alternate proposal addresses.

The main difference between the LGC alternate proposal and the Division's is that WPFs in the 6-12 TPY category get inspected twice per year in the LGC alternate proposal versus once per year in the Division's.

The initial EIA cost estimates for compressor stations in the 0-12 TPY category and the WPFs in the 0-6 TPY category, also proposed by the LGC to be inspected more frequently than the Division's proposal, remain as stated within the LGC - PHS.

The costs on the following worksheet are based off of data the LGC commissioned Terracon to develop for WPFs in the 6-12 TPY uncontrolled VOC range. The assumptions and results are included as rebuttal exhibits LGC - REB EXH A1, A2, and A3. These costs supersede the values for the 6-12 TPY facilities in the initial EIA, contained within the LGC - PHS.

Economic Impact Analysis for Biannual Inspections of Well Production Facilities as Recommended by the LGC

Number of Facilities	1412	6-12 TPY threshold
Inspections per facility per year	2	
VOC per facility - uncontrolled (6-12 TPY range)	9	TPY
Cumulative VOC - uncontrolled	12708	TPY
Current VOC capture rate	71.25%	(CDPHE EIA - Table 15)
Current VOC emissions - controlled	3654	TPY
Intended VOC capture rate	95%	(CDPHE EIA - Table 15)
Intended VOC emissions (with STEM and LDAR)	635	TPY (@ 95% effectiveness)
Potential VOC emissions avoided (w/ STEM & LDAR)	3018	TPY (going from 71.25% to 95% effectiveness)
Potential WPF VOC emissions avoided (w/ LDAR)	2598	TPY (CDPHE EIA Table 26, 6-12 TPY)
Total LDAR inspection costs @ 2x/year	\$1,503,547	using TVA1000B rental costs (see below)
Total LDAR inspection costs @ 2x/year	\$2,350,747	using FLIR camera rental costs (see below)
Total LDAR inspection costs @ 2x/year	\$1,327,986	CDPHE EIA (Table 27, 6-12 TPY); multiplied \$663K by 2 to compare with proposed LGC semi-annual inspections vs annual
Total LDAR inspection costs @ 2x/year	\$6,042,560	DGS Client Group PHS EX C (Table 12 Part I, 6-12 TPY); multiplied \$3M by 2 to compare with proposed LGC semi-annual inspections vs annual
Annual LDAR inspection costs per facility @ 2x/year	\$1,065	(w/ TVA 1000B)
Annual LDAR inspection costs per facility @ 2x/year	\$1,665	(w/ FLIR Camera)
Annual LDAR inspection costs per facility @ 2x/year	\$1,365	Average of TVA and FLIR
Annual LDAR inspection costs per facility @ 1x/year	\$926	(CDPHE EIA w/ FLIR - Table 14)
Cost per ton of VOC reductions (w/ LDAR)	\$579	(using TVA 1000B costs)
Cost per ton of VOC reductions @2x per year (w/ LDAR)	\$905	(using FLIR camera costs)
Cost per ton of VOC reductions (LDAR)	\$512	CDPHE EIA (Table 27, 6-12 TPY); multiplied \$256 by 2 to compare with proposed LGC semi-annual inspections vs annual
Cost per ton of VOC reductions (LDAR)	\$3,702	DGS EIA (Table 14, 6-12 TPY); multiplied \$1851 (Year 1) by 2 to compare with proposed LGC semi-annual inspections vs annual

Supporting data used to estimate LDAR inspection costs:

LDAR Inspection time	3 hours (per LGC REB EXH A1)	
Avg daily round trip distance	90 miles (@ 2 inspections per day)	
Per mile costs	0.56 per mile rate (2014 GSA)	
Avg speed	50 mph	
Travel time per inspection	0.9 hours	
Technician hourly rate	\$50	
Additional staff costs multiplier	1.55 (CDPHE EIA - Table 20)	
Overhead multiplier	1.10 (CDPHE EIA - Table 20)	
Fringe multiplier	1.30 (CDPHE EIA - Table 20)	
Labor costs per inspection w/travel time	\$432	
Mileage costs per inspection	\$25	
Total Labor and mileage costs per Inspection	\$457	
Total Annual Labor and Mileage Costs	\$1,291,747 (@ 2 inspections per year per facility)	
Total number of inspections	2824 LGC @ 2x per year	
Inspections per day	2 LGC estimate	
Number of days	1412 to complete	2824 inspections
TVA equipment costs (rental)	\$150 per day (Terracon)	
FLIR equipment costs (rental)	\$750 per day (Terracon)	
	\$211,800 Annual TVA Costs (LGC)	
	\$1,059,000 Annual FLIR Costs (LGC)	
	\$1,503,547 Total Annual Inspection Costs with TVA (LGC)	
	\$2,350,747 Total Annual Inspection Costs FLIR Costs (LGC)	

BEFORE THE COLORADO AIR QUALITY CONTROL COMMISSION
COLORADO DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

WORLDWIDE LIQUID SOLUTIONS, LLC ALTERNATIVE PROPOSALS

IN THE MATTER OF OIL & GAS RULEMAKING EFFORTS:
REGULATION NUMBER 3, PARTS A, B AND C
REGULATION NUMBER 6, PART A and
REGULATION NUMBER 7

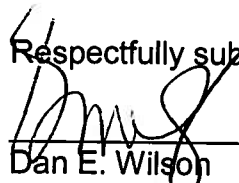
Worldwide Liquid Solutions, LLC, by and through its attorney, Dan E. Wilson, Attorney at Law, LLC, files its Alternative Proposals in the above referenced matter.

1. In its initial Request for Party Status, Worldwide Liquid Solutions ("WLS") suggested the alternative of deleting ethane and methane from proposed Rule. 7 (5CCR 10001-9), to wit:
 - a. In II. B. Exemptions, strike all proposed language for addition to the rule (specifically striking the addition of methane and ethane in Sections XVII and XVIII).
 - b. Consistent with this change, change all references throughout the draft proposed rule noted as "hydrocarbons" to "volatile organic compounds". A more accurate description would be to identify them as precursors to ozone producing compounds within the definition of the rules.
 - c. In XVII.C.4.c. Recordkeeping, please be informed that a properly functioning passive volatile organic compound absorption filter ("PVOCAF") will continue to capture VOCs in an upset condition until such filter is filled or replaced under a service schedule. This rule needs to be modified to reflect a release of "volatile organic compounds" released to the atmosphere, or to note repair of the "burp valve", or when the passive absorption filter is replaced.
2. Upon further review, WLS would suggest the complete incorporation of 40 CFR Part 60, subpart OOOO as revised through 9/23/2013.
 - a. Such incorporation would likely be made into Rule 6, Part A. Rule 3, Parts A, B and C could be promulgated. If done, Rule 7 would be stricken in its entirety.

b. Such action would bring the Air Quality Control Commission ("AQCC") current from its partial incorporation of 40 CFR Part 60, subpart OOOO on October 12, 2012.

3. A good faith argument can be made to limit the application of proposed Rule 7 to the Denver Metropolitan/North Front Range nonattainment areas. Such an effort would require a major effort to compile the necessary data supporting analyses to support Rule 7 even in these non-attainment areas. The analyses will not likely support the addition of the de minimis, negligibly reactive compounds of ethane and methane for pollution purposes but may prove more cost effective in these locations.

Respectfully submitted this 6th day of January, 2014.



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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was sent via email to the following persons whose names and addresses are listed below on January 6, 2014.

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BEFORE THE COLORADO AIR QUALITY CONTROL COMMISSION
COLORADO DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

WORLDWIDE LIQUID SOLUTIONS, LLC – ECONOMIC IMPACT ANALYSIS
STATEMENT

IN THE MATTER OF OIL & GAS RULEMAKING EFFORTS:
REGULATION NUMBER 3, PARTS A, B AND C
REGULATION NUMBER 6, PART A and
REGULATION NUMBER 7

Worldwide Liquid Solutions, LLC, by and through its attorney, Dan E. Wilson, Attorney at Law, LLC, files its Economic Impact Analysis in the above referenced matter.

A. SUMMARY

Worldwide Liquid Solutions (“WLS”) participated as a stakeholder in the above referenced rulemaking process. However, despite repeated promises by the Colorado Department of Public Health and Environment (“CDPHE” or “Division”) to hold technical working group sessions to evaluate emerging technical solutions, no such meetings were ever held by CDPHE, nor alternative solutions evaluated in connection with the proposed rules.

WLS manufactures a passive volatile organic compound (“VOC”) absorption filter (“PVOCAF”). The filter is passive and requires no outside source for electrical power to operate. Wind turbines or solar collection devices are adequate power sources for small storage tank filters to maintain negative pressure. The filters are housed in a non-absorptive, recyclable ‘short stack’ which holds a filter of absorptive carbon material that captures VOC compounds as they pass up the stack.

The PVOCAF is entirely constructed of material that can be recycled into a fresh filter. A WLS vendor will recover the captured VOCs and regenerate the carbon filtering material for reuse. Development of a full scale carbon recovery program is possible with a significant percentage of participants within the oil and gas industry.

The PVOCAF offers a low cost, low energy, carbon capturing, recyclable alternative to flaring and combustion devices without creating additional, secondary pollution. However, PVOCAF will not capture ethane and methane, not currently regulated by Quad O. The inclusion of ethane and methane in the draft Colorado Rule 7 will render this advanced technology unusable in Colorado.

When compared to published data from EPA, the PVOCAF demonstrates a cost savings advantage over flares and combustion devices for VOC emissions from storage tanks in many scenarios. The cost effectiveness of the PVOCAF is extended in remote areas where there is no electrical service or where generators would be required to power a flare or combustion device.

The PVOCAF offers an additional advantage over flares and combustion devices because it consumes no fuel (ethane and methane) to operate, reducing the cost of fuel and avoiding the secondary pollution of NOx, CO, methane and primarily CO2 created by these devices. Currently, EPA has set the Best System of Emission Reduction ("BSER") at 4 tpy VOC under Quad O determining that below this limit, flares and combustion devices are no longer cost effective, will create additional pollution and environmental impacts and consume too much energy to be effective. WLS is working with Wyoming, Texas, Utah, and U. S. EPA for use of the PVOCAF as an alternative to flaring. The PVOCAF may revolutionize the BSER for the oil and gas industry because it can cost effectively capture VOCs well below the current BSER limits.

B. ECONOMIC IMPACT ANALYSIS

WLS estimates that it can provide passive volatile organic compound absorption filters ("PVOCAF") for storage tanks at the initial start-up investment of \$1,000 per filter and \$1,100 per ton of VOC removal. This cost will include the initial potential to emit analysis, including VOC testing and gas chromatography. Actual VOC monitoring of the PVOCAF should be set at monthly to quarterly schedules depending on the initial potential to emit ("PET") determination or changes in tank usage. These estimates include maintenance, monitoring and filter replacement costs.

VOC (tpy)	PVOCAF	EPA	CDPHE
1	\$2100 per ton		
2	\$1600 per ton	\$10,000 per ton	
3	\$1433 per ton	\$6900 per ton	
4	\$1350 per ton	\$5100 per ton	
5	\$1300 per ton		
6	\$1267 per ton		
7	\$1243 per ton		
8	\$1225 per ton		
9	\$1211 per ton		
10	\$1200 per ton		
11	\$1191 per ton		
12	\$1183 per ton		

The chart above is based upon the cost estimates provided by WLS and what has been most currently published by EPA in connection with the Quad O revisions, 78 FR 58416, at page 58429 (9/23/13). The CDPHE cost projections have not yet been submitted as part of the rulemaking process. However, it should be noted that EPA has expressed concern over CDPHE's costs being used in the current rulemaking process. See, 78 FR at page 58429.

Please keep in mind that there is no secondary pollution or fuel cost to operate the PVOCAF, so there is no corresponding BSER limit. In other words, the PVOCAF can cost

effectively capture VOCs below the 4 tpy BSER limit established by EPA for flares and combustion devices.

WLS submits that the PVOCAF is a cost effective alternative to flares and combustion devices that should be utilized to capture VOCs in Colorado. The device has the potential to reduce VOC emissions below the current EPA BSER limit of 4 tpy VOC and could cost effectively be used in areas where VOC capture needs to occur below these limits, such as to protect residents in close proximity to VOC emissions or help achieve VOC compliance in non-attainment areas.

 Respectfully submitted this 30th day of January, 2014.

Dan E. Wilson
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CERTIFICATE OF SERVICE

This is to certify that I have duly served the within **Worldwide Liquid Solutions, LLC-Rebuttal Statement** upon all parties herein by e-mail or by depositing copies of same in the United States mail, first-class postage prepaid, at Denver, Colorado, this 30th day of January, 2014, addressed as follows:

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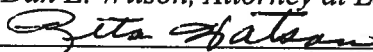
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Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems

May 2016

Prepared for

ONE Future Inc.

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page

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Acronyms and Abbreviations

Acronym / Abbreviation	Stands For
AR4	UNFCCC Fourth Assessment Report
Bcf	Billion Cubic Feet
CapEx	Capital Expenditures
CH ₄	Methane
CO ₂	Carbon Dioxide
CO ₂ e	Carbon Dioxide Equivalent
EDF	Environmental Defense Fund
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GWP	Global Warming Potential
HAP	Hazardous Air Pollutant
hp	Horsepower
IR	Infrared
LDAR	Leak Detection and Repair
LDCs	Local Distribution Companies
LNG	Liquefied Natural Gas
MAC	Marginal Abatement Cost
Mcf	Thousand Cubic Feet
MMcf	Million Cubic Feet
MMTCH ₄	Million Metric Tonnes Methane
MMTCO ₂ e	Million Metric Tonnes CO ₂ equivalent
scf	Standard Cubic Feet
scfd	Standard Cubic Feet per Day
scfh	Standard Cubic Feet per Hour
VRU	Vapor Recovery Unit

1. Executive Summary

Our Nation's Energy Future Coalition (ONE Future)¹ commissioned ICF to conduct this analysis of the marginal abatement cost (MAC) of various methane emission abatement technologies and work practices for the natural gas industry. The goal of this MAC analysis is threefold: (1) to identify the emission sources that provide the greatest opportunity for methane emission reduction from the natural gas system, (2) to develop a comprehensive listing of known emission abatement technologies for each of the identified emission sources, and (3) to calculate the cost of deploying each emission abatement technology and to develop a MAC curve for these emission reductions. The findings of this report will be utilized by ONE Future to develop segment-specific methane emission reduction goals that, when combined, will achieve a collective 1% (or less) emission target in the most cost-effective manner. This report will also assist each ONE Future member to customize its abatement strategy to fit its particular emission profile.

This analysis is based on a MAC curve model developed by ICF for the Environmental Defense Fund (EDF) in 2014. The current study incorporates more recent information on emissions and equipment costs and modified assumptions provided by the One Future participants. Appendix A summarizes and compares the key assumptions and results for the two studies. The study utilized the following approach:

- The baseline for methane emissions from the natural gas sector was established as the U.S. EPA Inventory of Greenhouse Gas Emissions for 2012 to match the baseline year employed in the U.S. methane emissions reduction goals.²
- A review of existing literature and additional analysis was conducted to identify the largest emission reduction opportunities; a cost-benefit estimate for each of the mitigation technologies was calculated.
- Interviews with One Future members, industry, technology innovators, and equipment vendors were conducted with a specific focus on identifying additional mitigation options and characterizing the cost and performance of the options.
- Information from the analysis was used to develop MAC curves for the methane reduction opportunities.

The analysis estimates reductions for each segment of the natural gas industry. The MAC analysis identified reductions totaling 88.3 Bcf/year of methane at a total annualized cost of \$296 million or \$3.35/Mcf of methane reduced for all segments except the distribution segment. The reductions for the distribution segment were calculated separately, and total 8.9 Bcf. An additional 12.3 Bcf of reductions were projected for the application of reduced emission completions for gas wells with hydraulic

¹ ONE Future is a coalition of companies that aims to achieve an average rate of methane emissions across the entire natural gas value chain that is one percent or less of total natural gas production.

² This analysis was completed prior to the updates to the methodologies incorporated into the U.S. Greenhouse Gas Inventory (GHGI) on April, 15, 2016.

fracturing. This was not required in 2012 but is now legally required, and was therefore included as a reduction from the baseline but not as part of the MAC analysis. This brings the total industry-wide methane reduction to 109.5 Bcf from the 2012 baseline emissions.

2. Approach and Methodology

2.1. Overview of Methodology

This section provides an overview of the methodology applied for this study. The major steps were:

- **Establish the 2012 Baseline for analysis** – the analysis started with the U.S. EPA inventory of methane emissions in the EPA Inventory of U.S. GHG Emissions (GHGI) published in April 2014 with data for 2012³. The most recent edition of the Inventory, released in April 2016, includes significant revisions, which are not included in this analysis. ICF expects future inventories will be updated to incorporate additional emissions and activity data collected from activities include:
 - ◆ Greenhouse Gas Reporting Program (GHGRP) inventory data collected in 2016 from companies in the gathering and boosting segment;
 - ◆ Information Collection Request (ICR)⁴ for additional regulations, which will require operators to provide key activity and emissions data; and
 - ◆ Private and Government-sponsored scientific studies, including several multi-million dollar research projects focused on methane emissions from oil and gas operations sponsored by Department of Energy⁵

Potential future updates to the GHGI may require a future update of this analysis to include those changes.

- **Identification of major sources and key mitigation options** – the next step was to identify the largest emitting sources in the inventory and the mitigation options that would be most effective and cost-effective for these sources.
- **Characterization of emission reduction technologies** – a key part of the study was to review and update information on the cost and performance of the selected mitigation technologies. Information was gathered from ONE Future Members, equipment manufacturers, other oil and gas companies, and other knowledgeable parties.
- **Development of the marginal abatement cost curves** – the technology information was applied to the emissions inventory to calculate the potential emission reduction and cost. The results were displayed in a series of marginal abatement cost curves.

The analysis calculates the annualized cost of emission reductions based on the capital and operating costs of the emission reduction technologies and the value of recovered gas in the production segment. This annualized cost is divided by the emission reductions to calculate the primary figure of merit -

³ U.S. EPA, "Inventory of U.S. Greenhouse Gas Emissions And Sinks: 1990-2012",
<http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html>

⁴ <https://www3.epa.gov/airquality/oilandgas/methane.html>

⁵ <http://www.netl.doe.gov/research/oil-and-gas/project-summaries/natural-gas-resources>

\$/unit of emissions reduced. This is expressed as \$/Mcf methane reduced, \$/tonne methane reduced, or \$/tonne CO₂ equivalent reduced. This figure of merit is consistent with the format used in other pollution control programs (SO₂, NO_x, VOC, etc.), which typically focus on \$/ton of pollutant reduced.

In the 2014 report for EDF, ICF concluded that the weighted average methane reduction cost was \$0.66/Mcf of methane reduced. The annual costs were also presented as normalized by gross natural gas production, dividing the annual cost by total U.S. natural gas production. Since methane emissions are only a few percent of total production, this value is very small – less than \$0.01/Mcf of gas produced in the U.S., depending on the specific assumptions. However this second metric is different from the approach typically used by industry and regulators to characterize the cost-effectiveness of emission reduction technologies and should not be compared to a \$/unit of methane reduced. In addition, the ONE Future sponsor companies reported that the metric that focuses on methane reduced is more useful to companies operating in different segments in assessing technologies and opportunities at new and existing facilities within each segment. Therefore, this report employs only the more commonly used weighted annual cost per methane reduced.

2.2. Identification of Targeted Emission Sources

Table 2-1 summarizes the largest emitting source categories for the oil and gas sectors by major source category in the EPA inventory for 2012. Due to the lack of specific data on the emission sources for offshore oil and gas production, the study focused on onshore production and offshore emissions are excluded from this list. The top 24 source categories account for nearly 90% of the total 2012 onshore methane emissions of 353 Bcf and were the primary focus of this analysis. The remaining 100+ categories each account for 1% or less of the total emissions. Although there are demonstrated methane reduction technologies that can provide cost-effective reductions for many of these smaller sources, these source categories were not included in this analysis due to their relative minor contribution to the overall emissions and reduction opportunity. In addition, the 2014 inventory for 2012 has a limited representation⁶ of the gathering segment and therefore the analysis likely does not represent the full potential reductions that could be achieved from this segment.

The distribution of emission sources is shown in Table 2-1 and Figure 2-1. Fugitive emissions are the largest emission source category overall across the oil and natural gas systems. Vented emissions from pneumatic controllers and pumps, and venting from wet seal centrifugal compressors are some of the significant methane emissions venting sources from the natural gas industry. Completion emissions from hydraulic fracturing were a significant source at this time however have since been regulated.

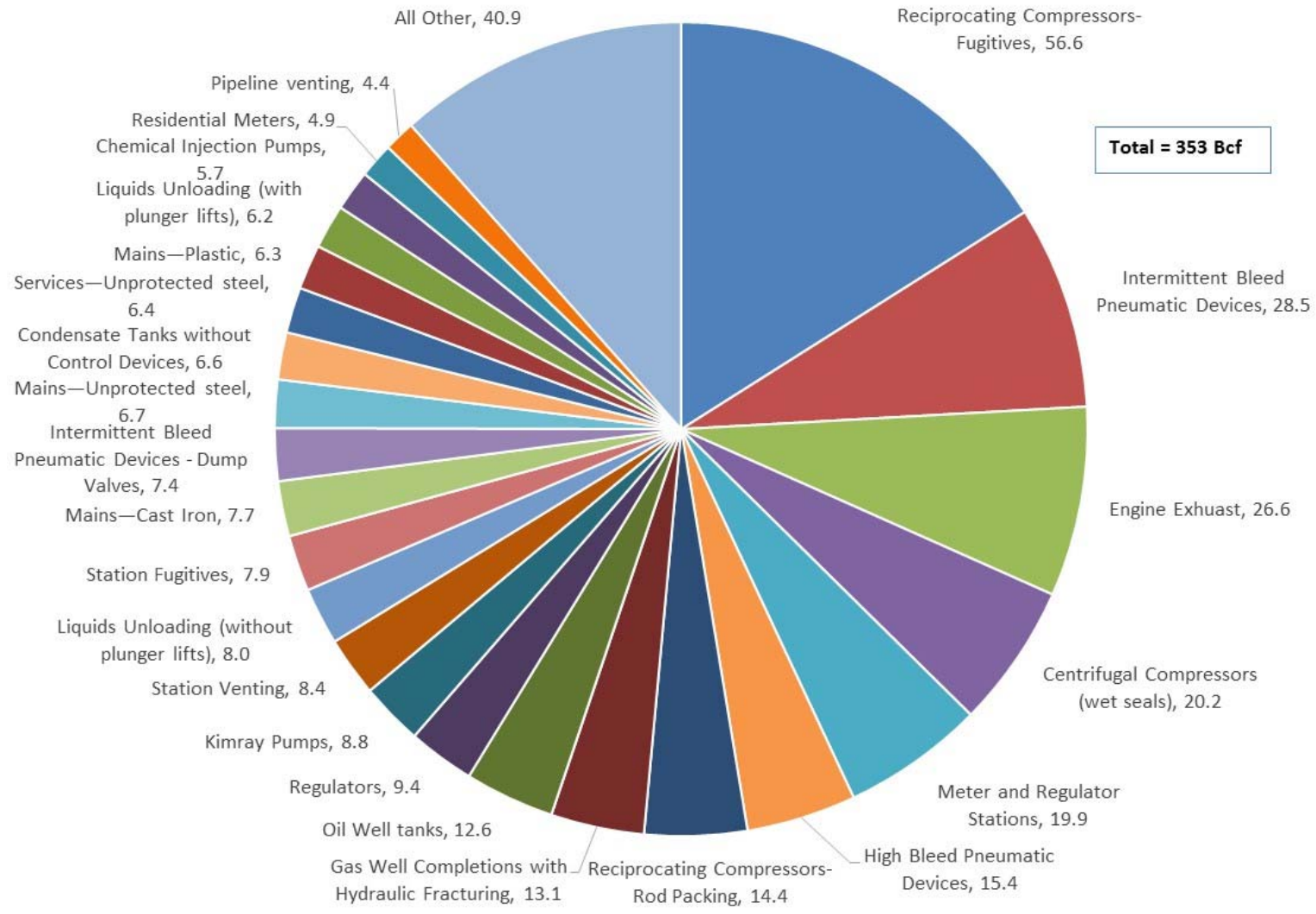
⁶ See Table 1, Inventory of U.S. GHG Emissions and Sinks: Revision Under Consideration for Gathering and Boosting Emissions, February 2016

Table 2-1 - Highest (Top-24) Emitting Onshore Methane Source Categories

Source	2012 Emissions (Bcf)	Cumulative Bcf	2012 Emissions (MM tonnes)	Percent of Total	Cumulative %	Type*
Reciprocating Compressors-Fugitives	56.6	56.6	1.1	16%	16%	F
Intermittent Bleed Pneumatic Devices	28.5	85.1	0.5	8%	24%	V
Engine Exhaust	26.6	111.7	0.5	8%	32%	V
Centrifugal Compressors (wet seals)	20.2	131.9	0.4	6%	37%	V
Meter and Regulator Stations	19.9	151.9	0.4	6%	43%	F
High Bleed Pneumatic Devices	15.4	167.3	0.3	4%	47%	V
Reciprocating Compressors-Rod Packing	14.4	181.7	0.3	4%	51%	V
Gas Well Completions with Hydraulic Fracturing	13.1	194.8	0.3	4%	55%	V
Oil Well tanks	12.6	207.4	0.2	4%	59%	V
Regulators	9.4	216.7	0.2	3%	61%	V
Kimray Pumps	8.8	225.5	0.2	2%	64%	V
Station Venting	8.4	233.9	0.2	2%	66%	V
Liquids Unloading (without plunger lifts)	8.0	241.9	0.2	2%	69%	V
Station Fugitives	7.9	249.8	0.2	2%	71%	F
Mains—Cast Iron	7.7	257.5	0.1	2%	73%	F
Intermittent Bleed Pneumatic Devices - Dump Valves	7.4	264.9	0.1	2%	75%	V
Mains—Unprotected steel	6.7	271.6	0.1	2%	77%	F
Condensate Tanks without Control Devices	6.6	278.2	0.1	2%	79%	V
Services—Unprotected steel	6.4	284.6	0.1	2%	81%	F
Mains—Plastic	6.3	290.9	0.1	2%	82%	F
Liquids Unloading (with plunger lifts)	6.2	297.1	0.1	2%	84%	V
Chemical Injection Pumps	5.7	302.8	0.1	2%	86%	V
Residential Meters	4.9	307.7	0.1	1%	87%	V
Pipeline venting	4.4	312.1	0.1	1%	88%	V

- F=Fugitive V=Vented

Figure 2-1 - 2012 Onshore Emissions (Bcf) from EPA Inventory



2.3. Selected Mitigation Technologies

The following sections describe the mitigation measures included in this analysis to address the high-emitting source categories identified in Table 2-1. The smaller sources individually were judged to have an insignificant effect on the overall emissions analysis even if cost-effective mitigation technologies were available. Much of the cost and performance data for the technologies is based on information from the EPA Natural Gas STAR program⁷ but was updated and augmented with information provided by industry and equipment vendor sources consulted during the EDF study. Further updates and information were provided by ONE Future members for this study.

This analysis attempts to define reasonable estimates of average cost and performance based on the available data and experiences of operators, including ONE Future members. The costs and performance of an actual individual project may not be directly comparable to the averages employed in this analysis because implementation costs and technology effectiveness are highly site-specific. Some technologies, like the efficiency of plunger-lifts for liquids unloading to reduce emissions, depend on the operating conditions of the well. Further, certain low-production or lower utilized compressor stations may have lower emissions. Costs for specific actual facilities could be higher or lower than the averages used in this analysis.

Several of the sources identified in Table 2-1 do not have commercially available mitigation technologies (e.g., engine exhaust) or are not currently cost-effective (e.g. cast iron main replacement). ICF analyzed various mitigation options for each of the 24 sources based on cost, reduction potential and market-penetration and considered 16 sources and mitigation measures for further modeling and evaluation.

Table 2-2 summarizes the mitigation measures applied in the analysis for each of the 16 major emission sources.

Table 2-2 - Summary of Mitigation Measures Modeled

Source	Mitigation Measure
Condensate Tanks w/o Control Devices	Install vapor recovery units
Wellhead Oil Tanks w/o Control Devices	Install vapor recovery units
Liquids Unloading - Wells w/o Plunger Lifts	Install plunger lift systems in gas wells
High Bleed Pneumatic Devices	Early replacement of high-bleed devices with low-bleed devices
Intermittent Bleed Pneumatic Devices	Replace with instrument air systems – intermittent
Chemical Injection Pumps	Replace pneumatic chemical injection pumps with Solar electric pumps
Kimray Pumps	Replace Kimray pumps with electric pumps

⁷ <http://www.epa.gov/gasstar/>

Source	Mitigation Measure
Pipeline Venting	Pipeline pump-down before maintenance
Centrifugal Compressors (wet seals)	Wet seal gas capture or dry seals
Transmission Station Venting	Redesign blowdown systems and alter ESD practice
Gas Well Completions - with Fracturing	Install flares – portable
Reciprocating Compressor Rod Packing	Replacement of compressor rod packing systems
Reciprocating Compressor Fugitives ⁸	Leak detection and repair (LDAR) ⁹
Compressor Station Fugitives ¹⁰	Leak detection and repair (LDAR)
Well Fugitives	Leak detection and repair (LDAR)
Gathering Station Fugitives	Leak detection and repair (LDAR)

⁸ Includes blowdown and unit isolation valves, connectors, other valves, meters, open-ended lines, and PRVs that are associated with the compressors.

⁹ LDAR here is used generically to mean a wide range of leak detection, inspection, and repair activities.

¹⁰ Includes valves, connectors, meters, open-ended lines, and pressure reducing valves (PRVs) that are located throughout the station and not associated with the compressors.

Table 2-3 summarizes the key characteristics (i.e. capital costs, operating costs and reduction efficiency) of the 16 measures modeled. (The assumptions and analytical approach for LDAR are addressed further below.) The costs are for U.S. Gulf Coast and are adjusted by regional cost factors in the MAC curve analysis in Section 3. The sources and derivation of these values are listed in Appendix B. Table 2-4 shows the baseline cost effectiveness (\$/Mcf, tonnes, or CO₂e of methane removed) for each measure modeled with and without credit for any recovered gas. The credit applies where emission reduction measures result in gas being recovered by the company. In the production segment, gas that is recovered can be sold and therefore has an economic value. In that case, the value of recovered gas is subtracted from the annual operating costs.

In the transmission and distribution segments, rate regulation typically requires pipeline and distribution companies to pass any cost reductions, including reduced losses, along to customers, thus the companies typically cannot capture the financial benefit of recovered gas. The contractual provisions for gathering, processing, and storage are variable but the ONE Future members reported that these companies typically do not take ownership of the gas but rather are paid a fee for their service. Reduced losses could result in increased throughput and increased recovery of the fee (which is much less than the value of the gas itself) but only if the metering point is downstream of the potential gas recovery.

Table 2-3 - Summary of Mitigation Measure Characteristics (Gulf-Coast Cost Basis)

Mitigation strategy	Capital Cost	Operating Cost	Percent Reduction
Early replacement of high-bleed devices with low-bleed devices	\$3,000	\$0	78%
Replacement of Reciprocating Compressor Rod Packing Systems	\$6,600	\$0	31%
Install Flares-Portable	\$30,000	\$6,000	98%
Install Plunger Lift Systems in Gas Wells	\$20,000	\$2,400	95%
Install Vapor Recovery Units	\$50,636	\$9,166	95%
Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	\$5,000	\$75	100%
Replace Kimray Pumps with Electric Pumps	\$10,000	\$2,000	100%
Pipeline Pump-Down Before Maintenance	\$0	\$30,155	80%
Redesign Blowdown Systems and Alter ESD Practices	\$15,000	\$0	95%
Wet Seal Degassing Recovery System for Centrifugal Compressors	\$70,000	\$0	95%
Replace with Instrument Air Systems - Intermittent	\$60,000	\$17,770	100%

The members also reported that the metering for most of these facilities is at the entry point of the facility, thus preventing the operator from capturing the value of recovered gas. Based on this information, the value of recovered gas was included only for the production sector in this study. This is a change from the 2014 EDF study. The gas price was assumed to be \$3/Mcf¹¹, reduced by 25% to account for royalties and fees, for a net value of \$2.25/Mcf¹².

¹¹ EIA Short Term Energy Outlook, March 9, 2016, Henry Hub spot prices are forecast to average \$3.11/MMBtu in 2017.

¹² A fuel price sensitivity analysis is included in Appendix A.

Table 2-4 – Calculated Emission Reduction Cost per Mitigation Technology or Practice (Gulf Coast Cost Basis)

Name	\$/Mcf* w/ Credit	\$/Mcf w/o Credit	\$/tonne CH ₄ w/Credit	\$/tonne CH ₄ w/o Credit	\$/tonne CO ₂ e ** w/Credit	\$/tonne CO ₂ e w/o Credit
Early replacement of high-bleed devices with low-bleed devices	\$4.91	\$7.61	\$257.01	\$398.49	\$10.28	\$15.94
Replacement of Reciprocating Compressor Rod Packing Systems	\$3.36	\$6.06	\$175.90	\$317.39	\$7.04	\$12.70
Install Flares-Portable	\$0.20	\$0.20	\$10.37	\$10.37	\$0.41	\$0.41
Install Plunger Lift Systems in Gas Wells	\$2.33	\$5.03	\$121.81	\$263.30	\$4.87	\$10.53
Install Vapor Recovery Units	-\$0.82	\$1.89	-\$42.72	\$98.76	-\$1.71	\$3.95
Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	\$2.16	\$4.86	\$112.90	\$254.38	\$4.52	\$10.18
Replace Kimray Pumps with Electric Pumps	-\$1.79	\$0.91	-\$93.98	\$47.50	-\$3.76	\$1.90
Pipeline Pump-Down Before Maintenance	\$1.14	\$3.84	\$59.70	\$201.19	\$2.39	\$8.05
Redesign Blowdown Systems and Alter ESD Practices	-\$4.10	\$0.98	-\$214.62	\$51.27	-\$8.58	\$2.05
Wet Seal Degassing Recovery System for Centrifugal Compressors	-\$2.38	\$0.32	-\$124.57	\$16.91	-\$4.98	\$0.68
Replace with Instrument Air Systems - Intermittent	-\$1.46	\$1.24	-\$76.49	\$65.00	-\$3.06	\$2.60

* Gas recovery credit is applied only for the Production Segment

** GWP=25

The annual cost was calculated as the annual amortized capital cost over the equipment life plus annual operating costs. This was divided by annual methane reductions to calculate the cost-effectiveness without credit for recovered gas. Where gas can be recovered and monetized by the operating company, the value of that gas was subtracted from the annual cost to calculate the cost-effectiveness with credit for recovered gas. The costs shown here are the baseline costs, which are adjusted for regional cost variation in the later MAC analysis. As noted earlier, these are average costs that may not reflect site-specific conditions at individual facilities.

Fugitive emissions are the unplanned loss of methane from pipes, valves, flanges, and other types of equipment. Fugitive emissions from reciprocating compressors, compressor stations (transmission, storage, and gathering), wells, and LDC metering and regulator equipment are the largest combined emission category, accounting for over 30% of the highlighted sources. The potential size and nature of these fugitive emissions can vary widely by industry segment and even by site.

Leak Detection and Repair (LDAR) is the generic term for the process of locating and repairing these fugitive leaks. There are a variety of techniques and types of equipment that can be used to locate and quantify these fugitive emissions. The analysis of LDAR cost and effectiveness for this study is a little different from the treatment of other measures because it is largely a function of labor required for inspections and repairs.

Extensive work has been done by EPA and others to document and describe these techniques, both in the Gas STAR reference materials and in several regulatory analyses, including for the EPA's NSPS Subpart OOOO¹³ and the Colorado Air Quality Control Commission Regulation Number 7 (5 CCR 1001-9)¹⁴. This study used both the Colorado regulatory analysis and the EPA Technical Support Document (TSD)¹⁵ for NSPS Subpart OOOO as the basis for the analytical framework. Additional cost information was provided by ONE Future members.

The key factors in the analysis are how much time it takes an inspector to survey each facility, how many inspections are required each year, how much reduction can be achieved, and how much time is required for repairs. ICF adapted the structure (but not all of the specific inputs) of the Colorado analysis, which calculates the capital and labor cost to field a full-time inspector, including allowances for travel and record-keeping (Table 2-5). Specific cost factors were updated based on input from the ONE Future member companies. The combined hourly cost was the basis for the cost estimates. The capital cost includes a variety of leak detection and measurement equipment, a truck and the cost of a record-keeping system. These are estimated average costs and are highly variable depending on site-

¹³ <http://www.epa.gov/airquality/oilandgas/>

¹⁴ <http://www.colorado.gov/cs/Satellite/CDPHE-AQCC/CBON/1251647985820>

¹⁵ U.S. EPA, "Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Supplemental Technical Support Document for the Final New Source Performance Standards".
<http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf>

specific conditions and scale. In addition, the Gathering and Boosting segment is included in the Production segment in these analysis due to the design of the EPA inventory.

Table 2-5 - LDAR Hourly Cost Calculation

Labor		Capital and Initial Costs	
Inspection Staff	\$86,155	FLIR Thermal Camera	\$122,200
Supervision (@ 20%)	\$17,231	Remote Methane Leak Detector (RMLD)	\$20,000
Overhead (@10%)	\$8,616	Photo Ionization Detector	\$5,000
Travel (@0%)	\$0	Flame Ionization Detector	\$12,000
Recordkeeping (@5%)	\$4,308	Hi-Flow Sampler	\$21,450
Reporting (@0%)	\$0	Miscellaneous	\$3,000
Fringe (@50%)	\$43,078	Truck	\$22,000
Subtotal Costs	\$159,387	Monitoring system	\$14,500
		Total	\$220,150
Hours/yr.	1880	Training Dollars	\$6,782
Hourly Rate	\$84.78	Amortized Capital+Training	\$59,864
		Annual Labor	\$207,203
Training Hours	80	Annual Total	\$267,067
Training Dollars	\$6,782		
		Total Hourly Rate	\$142.06

Many analyses have used facility component counts and historical data on the time required to inspect each component to estimate facility survey times. However, the use of the infrared camera technology allows much shorter survey times¹⁶ and the EPA and Colorado time estimates have been criticized as too long. The estimates here are based on ICF and ONE Future company experience. ICF added additional time for training relative to the Colorado analysis.

ICF then adopted the baseline emission values for wells, gathering and transmission stations, and processing stations from the EPA NSPS analysis¹⁵. The 2014 EDF analysis had very limited data for LDC

¹⁶ Robinson, D, et. al., "Refinery Evaluation of Optical Imaging to Locate Fugitive Emissions". Journal of the Air & Waste Management Association. Volume 57 June 2007.

programs and resulted in very high reduction costs. Since a different approach was taken for the LDC segment in this analysis (see below) LDCs were not included here.

Table 2-6 summarizes the assumptions for the overall LDAR calculation. This analysis assumes annual emission surveys for all facilities. The reduction is assumed to be a 40% reduction, consistent with the experience of ONE Future members. In addition to the surveys, the estimate includes one initial visit to each site to inventory the equipment (equivalent hours to two inspection visits for each site with cost averaged over five years) and additional visits for repairs. Gas processing plants are already subject to some LDAR requirements for conventional pollutants, which result in co-benefit methane reductions. The miscellaneous fugitive emissions for gas processing were below the size threshold for this analysis but the costs developed here for gas processing are applied to compressors in that segment.

Table 2-6 – Cost Calculation – Annual LDAR

	Well Pads	Processing	Transmission
Methane Mcf/yr ¹⁵	3,057	5,986	3,605
% Reduction	40%	40%	40%
Reduction Mcf	1,223	2,394	1,442
Hours each Inspection (includes survey, travel, recordkeeping, review and training)	5.5	40	32
Frequency (per year)	1	1	1
Annual Inspection Cost	\$781	\$5,682	\$4,546
Initial Set-Up	\$156	\$1,136	\$909
Repair Labor Cost	\$781	\$5,682	\$4,546
Total Cost/yr	\$1,719	\$12,501	\$10,001
Recovered Gas Value*	\$3,303	NA	NA
Net Cost	-\$1,584	\$12,501	\$10,001
Cost Effectiveness (\$/Mcf CH ₄ reduced)	-\$1.30	\$5.22	\$6.94

*Gas at \$3/Mcf minus royalty = \$2.25/Mcf

Some repairs can be made at the time of the survey, such as tightening valve packing or flanges, but others will require additional repair time. This analysis assumes repair time equivalent to one survey visit for each facility for repairs each year. The capital cost of larger repairs is not included on the assumption that these repairs would need to be made anyway and the LDAR program is simply alerting the operator to the need. This lower repair estimate takes into account that:

- These are average values across facilities – not every facility will require repairs.
- These are average values over time – not every facility will need repairs every year while being monitored on a continuing basis.
- Some or all of cost of major repairs is assumed to be part of regular facility maintenance.

Replacement costs for large diameter, high pressure components are significantly greater than these average annual repair costs. The replacement frequency for large diameter, high pressure components at any individual facility cannot be accurately predicted or estimated.

The value of reduced gas losses is credited to the program for production only. These final reduction cost values were used for the analysis.

2.4. Treatment of LDC Reductions

The 2014 EDF study found that methane emission reductions from LDCs were extremely expensive, mostly due to the low baseline emissions and the high capital cost of some options, such as cast iron pipe replacement. Cast iron mains have been identified as a significant emission source, however they are primarily located in congested urban areas where replacement or repair is very expensive, reported as \$1 million to \$3 million per mile. This makes for a very expensive control option based purely on emission reduction. Moreover, these expenditures must be approved by state utility commissions, whose purview typically does not extend to environmental remediation of this type. That said, approximately 3% of cast iron mains are being replaced each year for safety reasons, so the emissions are gradually declining.

For this study, a separate analysis of emission reductions was developed for the LDC segment to account for reductions that will be undertaken even though they may not be cost-effective as emission control measures alone. The analysis assumed three types of activities:

- Cast iron main replacement at 3% per year
- Unprotected steel pipe replacement at 3% per year
- Miscellaneous other emission reduction measures such as: service line replacement, blowdown gas recovery, hot tapping, M&R Station upgrades, and dig-in mitigations, assumed to be 6% of the remaining emissions (excluding cast iron and unprotected steel mains) between 2012 and 2025.

Using the baseline emissions and the emission factors from the EPA 2012 inventory, these emission reductions were calculated as:

- Cast iron main replacement – 2.9 Bcf
- Unprotected steel pipe replacement – 2.5 Bcf
- Miscellaneous other emission reduction measures – 3.5 Bcf

2.5. Completion Emissions from Hydraulic Fracturing

Gas well completion emissions from hydraulic fracturing were estimated at 13.1 Bcf in the 2012 inventory. These emissions were regulated during the second half of 2012 and are assumed to be controlled going forward. Therefore they are not included in the MAC analysis but are counted as a reduction of 12.3 Bcf in the overall reductions from the base year.

2.6. Source Categories Not Addressed

Several source categories with relatively large emissions were not addressed in the analysis. The sources and the reasons for their treatment are summarized below.

- **Off-shore oil and gas production** – As noted earlier, the EPA inventory provides very limited data on offshore emissions, which were not adequate to apply the methodology used for other sources. This is an area in which further analysis would probably yield additional opportunities for reduction.
- **Engine exhaust** – The exhaust from gas-burning engines and turbines contains a small amount of unburned methane from incomplete combustion of the fuel. While it is a small percentage, it is significant in aggregate. Oxidation catalyst devices are used to reduce unburned emissions of other hydrocarbons in the exhaust but they are not effective at reducing emissions of methane due to its lower reactivity. However, new catalysts are being developed, in part for natural gas vehicles, which may be applicable to these sources. This is a topic for further research and technology deployment.
- **Other sources** – There are additional cost-effective measures for methane reduction that have been identified by the EPA Gas STAR program and others. They are not included here because this report focuses only on the largest emitting sources. However, their omission should not be taken to indicate that the measures listed here are the only cost-effective methane reduction measures.
- **Gathering and Boosting** – The gathering and boosting segment is not called out as a separate segment in the 2014 edition of the EPA inventory for 2012 and therefore was not addressed as a separate source of potential reductions in this study. The 2016 edition has developed new emission factors and significantly increased the activity counts in the gathering segment, however these higher emissions and potential reductions were not included in this analysis, which was completed prior to that release. Since the GHGRP now mandates reporting of emissions data from such facilities, and with the data to be gathered by EPA pursuant to the ICR process, we expect further updates in future GHGI releases. Further, several key government-sponsored studies of emissions from gathering and boosting facilities will be published by the end of 2016. All of this data will support future updates to the methane emissions profile from this segment and available abatement potential.

3. Analytical Results

3.1. Development of Emission Control Cost Curves

Section 2 identified 16 discrete control technologies and the associated costs, reduction potential, and cost-effectiveness in terms of annualized cost per ton or Mcf of methane reduced based on Gulf Coast region capital costs. In this Section 3, we model the cumulative reductions and marginal abatement costs from a 2012 U.S. methane emissions baseline for the oil and natural gas sector, employing the technology-level data generated in Section 2. Employing data from the EPA 2012 Greenhouse Gas Inventory and source/control technology data presented in Section 2, adjusted for regional cost differences, ICF computed the methane abatement potential from the natural gas sector from a 2012 baseline.

The model developed for this task includes the individual source categories for each segment of the oil and gas industry. Mitigation technologies are matched to each source or individual measure in various segments of the oil and gas value chain. The model calculates the reduction achieved for each source within each segment and calculates the cost of control based on the capital and operating costs, the equipment life, and where appropriate, the value of recovered gas. Key global input assumptions include: whether a particular segment is able to monetize the value of recovered gas, the value of gas, and the discount rate/cost of capital. As discussed above, the value of recovered gas was included only for the production segment and the gas price was assumed to be \$3/Mcf minus 25% for royalties and fees, for a net value of \$2.25/Mcf. A 10% discount rate was used for the analysis. These calculations include two factors that were not included in the baseline costs presented in Section 2:

- A construction cost index is used to account for regional cost differences, which averages 15% higher than the baseline Gulf Coast costs.
- The methane content is adjusted depending on whether the application is upstream or downstream in the value chain. This adjustment affects the value of recovered gas where the gas value can be monetized.

These two factors result in some of the costs in the MAC curve results presented in this chapter being higher than the baseline costs presented in Section 2. These and other key assumptions are listed in Appendix A.

Table 3-1 lists the emission reduction measures by industry segment with their reduction and cost, depicted in several formats. The total reduction is 88.3 Bcf/year of methane from the U.S. oil and gas segment at a total annualized cost of \$296 million or \$3.35/Mcf of methane reduced from the 2012 baseline. The reductions for the LDC segment calculated separately total 8.9 Bcf and the reductions from reduced emission well completions result in a total reduction of 109.5 Bcf of methane reduction.

Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems
Analytical Results

Table 3-1 – Annualized Methane Reduction and Cost – U.S.

Segment - Mitigation Option	Bcf CH ₄ Reduced	Gg CH ₄ Reduced	MMTonnes CO ₂ e	\$/Mcf CH ₄ Reduced	\$/Mcf Natural Gas Reduced	\$/Tonne CO ₂ e
Gas Processing - LDAR Processing	7.4	141.8	3.6	\$5.98	\$4.98	\$12.43
Gas Processing - Replace Kimray Pumps with Electric Pumps	0.1	2.5	0.1	\$1.04	\$0.87	\$2.16
Gas Processing - Replacement of Reciprocating Compressor Rod Packing Systems	0.3	6.0	0.2	\$6.94	\$5.78	\$14.42
Gas Processing - Wet Seal Degassing Recovery System for Centrifugal Compressors	7.5	144.7	3.6	\$0.37	\$0.31	\$0.77
Gas Production - Early replacement of high-bleed devices with low-bleed devices	5.3	101.9	2.6	\$6.02	\$5.23	\$12.50
Gas Production - Install Plunger Lift Systems in Gas Wells	2.3	43.9	1.1	\$3.06	\$2.66	\$6.35
Gas Production - Install Vapor Recovery Units	1.6	30.1	0.8	(\$0.54)	(\$0.47)	(\$1.12)
Gas Production - LDAR Wells	3.3	64.2	1.6	(\$1.09)	(\$0.95)	(\$2.26)
Gas Production - Replace Kimray Pumps with Electric Pumps	4.3	81.8	2.1	(\$1.66)	(\$1.45)	(\$3.45)
Gas Production - Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	2.7	51.4	1.3	\$2.86	\$2.49	\$5.95
Gas Production - Replacement of Reciprocating Compressor Rod Packing Systems	0.6	11.2	0.3	\$4.24	\$3.69	\$8.81
Gas Storage - Early replacement of high-bleed devices with low-bleed devices	0.1	1.8	0.0	\$8.72	\$8.14	\$18.11
Gas Storage - LDAR Transmission	2.9	56.2	1.4	\$7.95	\$7.42	\$16.51
Gas Storage - LDAR Wells	0.2	4.4	0.1	\$1.61	\$1.50	\$3.35
Gas Storage - Redesign Blowdown Systems and Alter ESD Practices	1.2	23.4	0.6	\$1.12	\$1.05	\$2.33
Gas Storage - Replace with Instrument Air Systems - Intermittent	0.1	2.2	0.1	\$1.42	\$1.33	\$2.95
Gas Storage - Replacement of Reciprocating Compressor Rod Packing Systems	0.4	6.9	0.2	\$6.94	\$6.49	\$14.42

Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems
Analytical Results

Segment - Mitigation Option	Bcf CH ₄ Reduced	Gg CH ₄ Reduced	MMTonnes CO ₂ e	\$/Mcf CH ₄ Reduced	\$/Mcf Natural Gas Reduced	\$/Tonne CO ₂ e
Gas Storage - Wet Seal Degassing Recovery System for Centrifugal Compressors	0.8	14.5	0.4	\$0.37	\$0.35	\$0.77
Gas Transmission - Early replacement of high-bleed devices with low-bleed devices	0.5	9.5	0.2	\$8.72	\$8.14	\$18.11
Gas Transmission - LDAR Transmission	14.0	268.5	6.7	\$7.95	\$7.42	\$16.51
Gas Transmission - Pipeline Pump-Down Before Maintenance	2.8	53.9	1.4	\$4.40	\$4.11	\$9.14
Gas Transmission - Redesign Blowdown Systems and Alter ESD Practices	6.4	122.5	3.1	\$1.12	\$1.05	\$2.33
Gas Transmission - Replace with Instrument Air Systems - Intermittent	0.6	11.2	0.3	\$1.42	\$1.33	\$2.95
Gas Transmission - Replacement of Reciprocating Compressor Rod Packing Systems	1.8	35.4	0.9	\$6.94	\$6.49	\$14.42
Gas Transmission - Wet Seal Degassing Recovery System for Centrifugal Compressors	7.4	141.6	3.6	\$0.37	\$0.35	\$0.77
Oil Production - Early replacement of high-bleed devices with low-bleed devices	4.6	88.5	2.2	\$6.02	\$5.01	\$12.50
Oil Production - Install Vapor Recovery Units	6.0	114.7	2.9	(\$0.54)	(\$0.45)	(\$1.12)
Oil Production - LDAR Wells	0.0	0.3	0.0	(\$1.09)	(\$0.91)	(\$2.26)
Oil Production - Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	1.9	36.1	0.9	\$2.86	\$0.00	\$5.95
Oil Production - Replace with Instrument Air Systems - Intermittent	1.1	20.6	0.5	(\$1.28)	\$0.00	(\$2.66)
Total	88.3	1,699.8	0.9			
Gas Production - Reduced Emission Completions	12.3	236.4	5.9	N/A	N/A	N/A
Gas Distribution - Cast Iron Main Replacement	2.9	55.6	1.4	N/A	N/A	N/A
Gas Distribution - Bare Steel Replacement	2.5	47.9	1.2	N/A	N/A	N/A
Gas Distribution - Miscellaneous	3.5	67.1	1.7	N/A	N/A	N/A
Grand Total	109.5	2,106.8	11.1			

The results can also be presented as a Marginal Abatement Cost Curve (MAC curve), shown in Figure 3-1. This representation shows the emission reductions sorted from lowest to highest cost-of-reduction and shows the amount of emission reduction available at each cost level. The vertical axis shows the cost per unit in \$/Mcf of methane reduced. A negative cost-of-reduction indicates that the measure has a positive financial return, i.e. saves money for the operator. The horizontal width of the bars shows the amount of reduction. The area within the bars is the total cost per year. The area below the horizontal axis represents savings and the area above the axis represents cost. The net sum of the two is the total net cost per year.

Figure 3-1 – Example MAC Curve

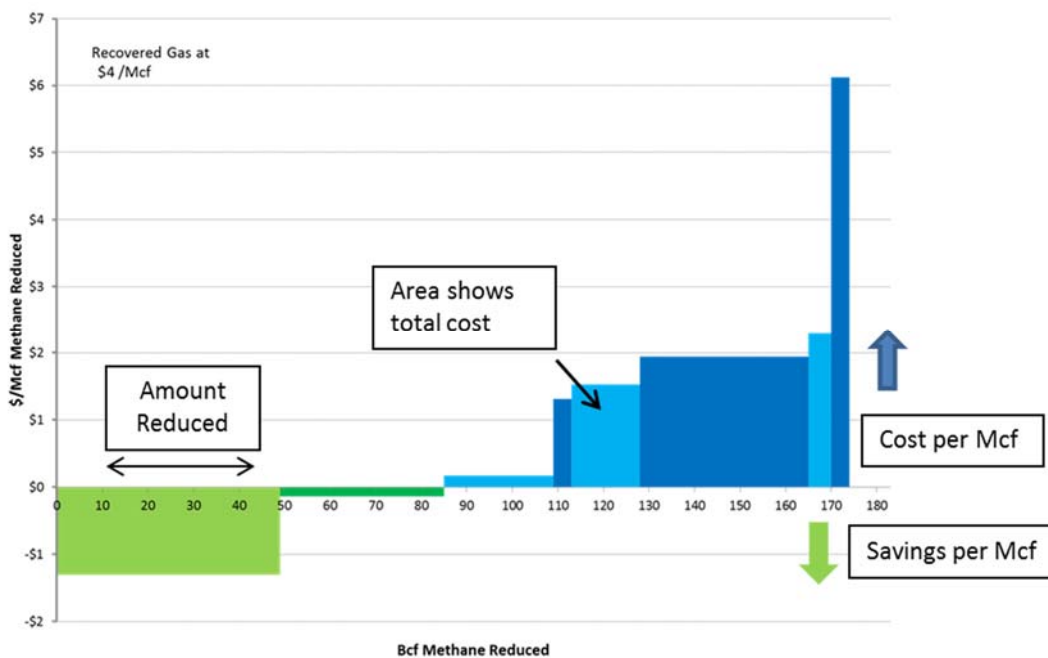


Figure 3-2 shows the reduction for each measure across all industry segments in the MAC curve format. Figure 3-3 shows the reduction in methane emissions by industry segment. The transmission and production sectors have the greatest reductions. The costs for each sector depend on the particular mitigation options available in each and their aggregate cost.

Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems
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Figure 3-2 – National Aggregate MAC Curve by Measure

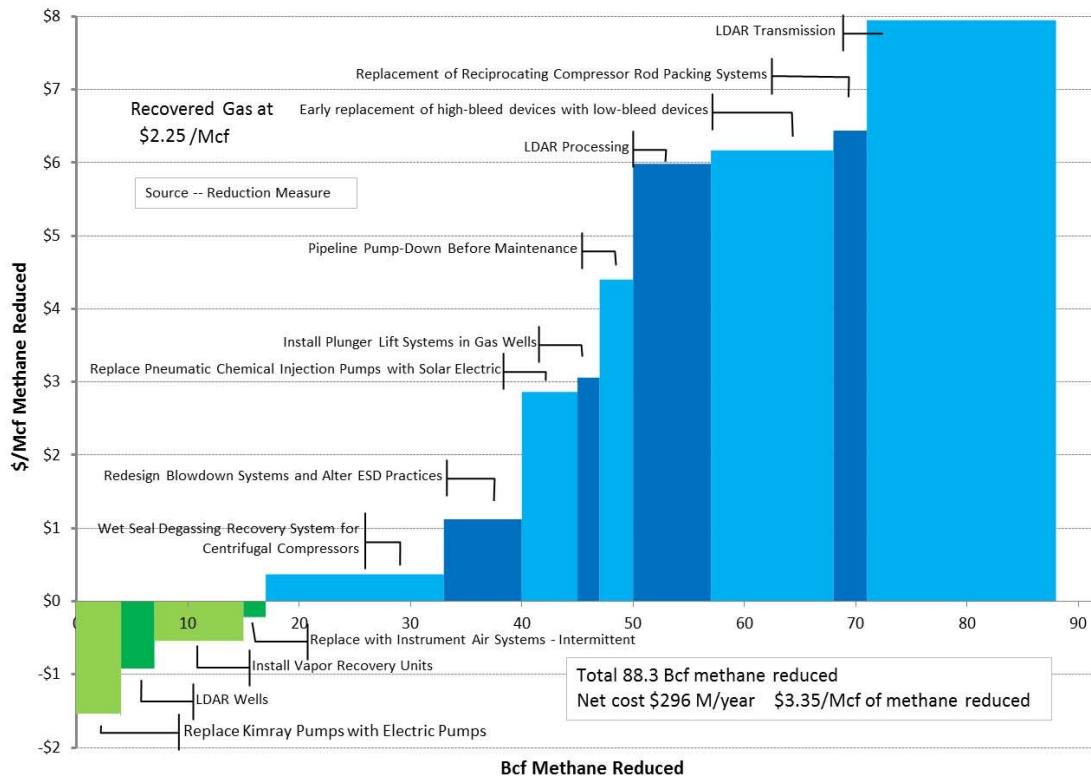
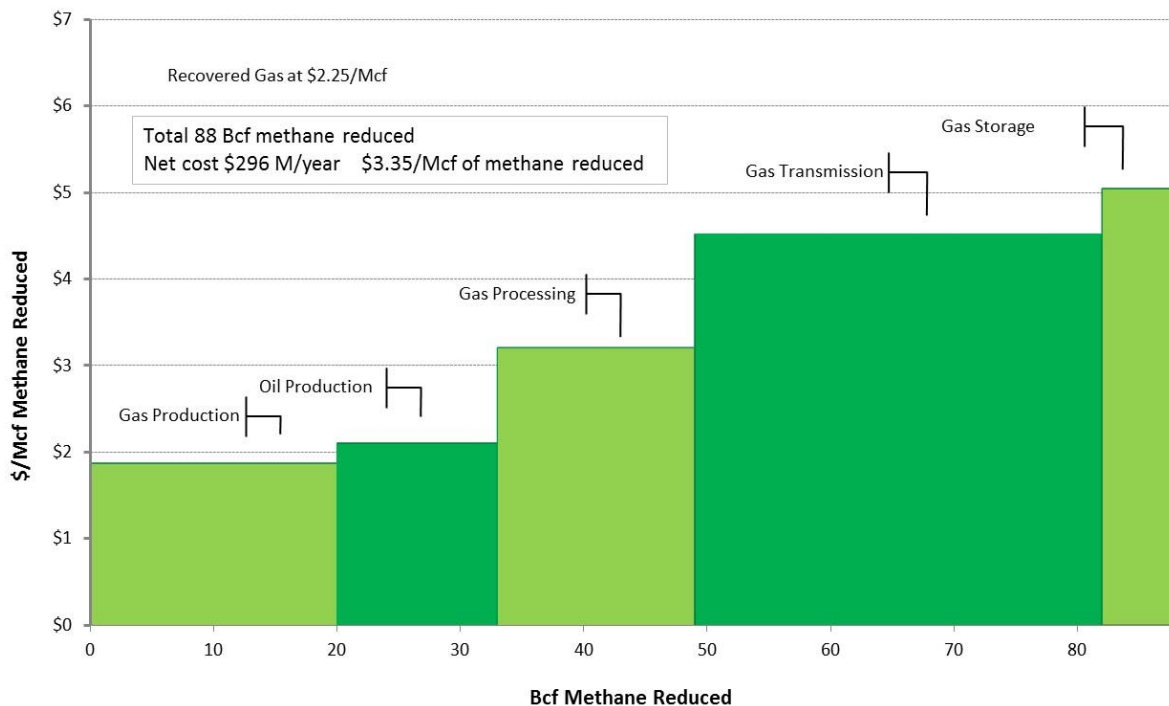


Figure 3-3 – National Aggregate MAC Curve by Industry Segment



Appendix A.

Summary and Comparison of Assumptions and Results

This section summarizes and compares the key assumptions and results for this study and the 2014 EDF study. The assumptions for each study were largely specified by the clients for each. Table A-1 summarizes some of the key assumptions and results. The primary difference in total reduction volume is the lower reduction from less frequent LDAR and the smaller baseline in the current study due to a different base year and exclusion of the distribution segment.

Table A-1 - Summary of Baseline Assumptions and MAC Curve Results

	ONE Future 2016	EDF 2014
Inventory Baseline	EPA Inventory 2012 – 353 Bcf methane	EPA Inventory 2011 modified and projected to 2018 – 404 Bcf methane
Natural Gas Price	\$2.25/Mcf (\$3/Mcf – 25% royalty and fee payments)	\$4/Mcf
LDAR Frequency and reduction	Annual – 40%	Quarterly – 60%
Gas Value Credit for Reductions	Production segment only	All except transmission and distribution
Net Annualized Cost	\$296 million	\$108 million
Annual reduction	88.3 Bcf methane	163 Bcf methane
Average cost of reduction	\$3.35/Mcf methane reduced	\$0.66/Mcf methane reduced

The primary drivers of the difference in the average cost of reduction between the two studies are the different gas price and the assumptions on which sectors can monetize the value of recovered gas. Table A-2 provides a sensitivity analysis of the gas price effect on the annualized cost of reduction per Mcf.

Table A-2 – Cost per Mcf of Methane Reduced – Gas Price Sensitivity

Gas Price	ONE Future 2016	EDF 2014
\$2.25/Mcf	\$3.35	
\$3.00/Mcf	\$3.01	\$1.48
\$4.00/Mcf	\$2.55	\$0.66
\$5.00/Mcf		-\$0.15

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Table A-3 - Mitigation Technology Characteristics – ONE Future 2016

Mitigation strategy	Capital Cost	Operating Cost	Percent Reduction	\$/Mcf* w/ Credit	\$/Mcf w/o Credit
Early replacement of high-bleed devices with low-bleed devices	\$3,000	\$0	78%	\$4.91	\$7.61
Replacement of Reciprocating Compressor Rod Packing Systems	\$6,600	\$0	31%	\$3.36	\$6.06
Install Flares-Portable	\$30,000	\$6,000	98%	\$0.20	\$0.20
Install Plunger Lift Systems in Gas Wells	\$20,000	\$2,400	95%	\$2.33	\$5.03
Install Vapor Recovery Units	\$50,636	\$9,166	95%	-\$0.82	\$1.89
Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	\$5,000	\$75	100%	\$2.16	\$4.86
Replace Kimray Pumps with Electric Pumps	\$10,000	\$2,000	100%	-\$1.79	\$0.91
Pipeline Pump-Down Before Maintenance	\$0	\$30,155	80%	\$1.14	\$3.84
Redesign Blowdown Systems and Alter ESD Practices	\$15,000	\$0	95%	-\$4.10	\$0.98
Wet Seal Degassing Recovery System for Centrifugal Compressors	\$70,000	\$0	95%	-\$2.38	\$0.32
Replace with Instrument Air Systems - Intermittent	\$60,000	\$17,770	100%	-\$1.46	\$1.24

Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems
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Table A-4 – Mitigation Technology Characteristics – EDF 2014

Name	Capital Cost	Operating Cost	Percent Reduction	\$/Mcf w/ Credit	\$/Mcf w/o Credit
Early replacement of high-bleed devices with low-bleed devices	\$3,000	\$0	97%	-\$3.08	\$1.99
Early replacement of intermittent-bleed devices with low-bleed devices	\$3,000	\$0	91%	\$0.58	\$5.65
Replacement of Reciprocating Compressor Rod Packing Systems	\$6,000	\$0	35%	\$1.82	\$6.89
Install Flares-Completion	\$50,000	\$6,000	98%	N/A	\$1.86
Install Flares-Venting	\$50,000	\$6,000	98%	N/A	\$0.26
Liquid Unloading – Install Plunger Lift Systems in Gas Wells	\$20,000	\$2,400	95%	-\$0.05	\$5.03
Install Vapor Recovery Units on Tanks	\$100,000	\$7,500	95%	-\$0.51	\$4.57
Transmission Station Venting –Redesign Blowdown Systems /ESD Practices	\$15,000	\$0	95%	-\$4.10	\$0.98
Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	\$5,000	\$75	100%	-\$0.22	\$4.86
Replace Kimray Pumps with Electric Pumps	\$10,000	\$2,000	100%	-\$4.17	\$0.91
Pipeline Venting – Pump-Down Before Maintenance	\$0	\$12,000	80%	-\$4.67	\$0.41
Wet Seal Degassing Recovery System for Centrifugal Compressors	\$50,000	\$0	95%	-\$4.87	\$0.21
LDAR Wells	\$169,923	\$146,250	60%	\$2.52	\$7.60
LDAR Gathering	\$169,923	\$146,250	60%	\$0.91	\$5.98
LDAR Large LDC Facilities	\$169,923	\$146,250	60%	\$10.03	\$14.45
LDAR Processing	\$169,923	\$146,250	60%	-\$0.98	\$4.10
LDAR Transmission	\$169,923	\$146,250	60%	-\$2.28	\$2.15

Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems
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Table A-5 – Annualized Cost and Reduction Comparison

Source/Measure	EDF 2014			ONE Future 2016		
	Annualized Cost (\$ million/yr)	Bcf Methane Reduced/yr	\$/ MCF Methane Reduced	Annualized Cost (\$ million/yr)	Bcf Methane Reduced/yr	\$/ MCF Methane Reduced
Replace Kimray Pumps with Electric Pumps	-\$23.4	5.8	-\$4.05	-\$7.0	4.4	-\$1.58
Wet Seal Degassing Recovery System for Centrifugal Compressors	-\$58.7	19.1	-\$3.07	\$5.8	15.7	\$0.37
Compressor Stations (Storage)--LDAR	-\$4.5	1.5	-\$3.03	Included in Transmission		
Early replacement of high-bleed devices with low-bleed devices	-\$67.4	25.4	-\$2.65	\$64.9	10.5	\$6.17
Reciprocating Compressor Fugitives--LDAR	-\$10.5	32.3	-\$0.33	Included in Transmission		
Condensate Tanks w/o Control Devices--VRU	\$0.1	0.4	\$0.21	-\$4.1	7.6	-\$0.54
Stranded Gas Venting from Oil Wells--Flares	\$2.4	8.2	\$0.30	NA		
Oil Tanks--VRU	\$1.8	5.5	\$0.33	Included with Condensate Tanks		
Pipeline Pump-Down Before Maintenance	\$2.3	4.2	\$0.53	\$12.4	2.8	\$4.40
Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	\$2.7	4.8	\$0.57	\$13.1	4.6	\$2.86
Install Plunger Lift Systems in Gas Wells	\$1.2	1.6	\$0.74	\$7.0	2.3	\$3.06
Redesign Blowdown Systems and Alter ESD Practices	\$7.5	5.9	\$1.27	\$8.5	7.6	\$1.12
Gathering and Boosting Stations--LDAR	\$5.0	3.3	\$1.51	Included in Production		
Intermittent Bleed Pneumatic Devices--Low Bleed	\$20.9	12.1	\$1.72	NA		
Replace with Instrument Air Systems - Intermittent	NA			-\$0.4	1.8	-\$0.22
Oil Well Completions - with Fracturing--Flares	\$14.5	6.8	\$2.13	NA		
Compressor Stations (Transmission)--LDAR	\$7.7	2.8	\$2.79	\$134.3	16.9	\$7.95
Well Fugitives--LDAR	\$43.9	12.5	\$3.51	-\$3.3	3.6	-\$0.92

Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems
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Replacement of Reciprocating Compressor Rod Packing Systems	\$22.3	3.6	\$6.11	\$20.0	3.1	\$6.44
LDC Meters and Regulators--LDAR	\$140.6	7.1	\$19.75	NA		
Grand Total	\$108.3	162.9	\$0.66	\$295.9	88.3	\$3.35

Appendix B. Data Sources

The follow notes explain the sources and derivation of the capital cost (Capex), operating cost (Opex), and emission reduction potential of the emission reduction options assessed in this study. The primary sources are a variety of EPA sources – particularly data from the Gas STAR program, the Greenhouse Gas Reporting, and support documents from NSPS OOOO, as well as industry comments received during the 2014 EDF study, and comments from the ONE Future sponsors of this study. Each emission reduction option is discussed below:

- **Early replacement of high-bleed devices with low-bleed devices** – Capex \$3,000, Opex \$0, Reduction 78%. The Capex and Opex were based on Gas STAR data updated by industry review in both studies. There is no incremental Opex for pneumatic devices. The reduction estimate was based on the performance of high bleed and low bleed pneumatic devices found in two field measurement studies completed by the University of Texas^{17, 18} and sponsored by industry participants and EDF.
- **Replacement of Reciprocating Compressor Rod Packing Systems** – Capex \$6,600, Opex \$0, Reduction 31%. The Capex was based on Gas STAR data updated by industry in both studies. There is no incremental Opex for this measure. The reduction estimate was based on an analysis by ICF that calculates the reductions due to more frequent replacement of rod packing seals relative to less frequent replacement.
- **Install Flares-Portable** – Capex \$30,000, Opex \$6,000, Reduction 98%. The Capex and Opex were based on industry input during both the EDF and ONE Future studies. The reduction is an EPA Gas STAR/inventory assumption of 98% flare combustion efficiency. Additional information was derived from GHGRP Subpart W.
- **Install Plunger Lift Systems in Gas Wells** – Capex - \$20,000, Opex \$2,400, Reduction 95%. These values were based on industry input during both studies. They do not include the value of increased production, which is typically the primary driver for liquids unloading. The cost and effectiveness of plunger lifts are highly variable depending on the well characteristics. Plunger lifts can be an effective mitigation measure for certain wells at certain times over their operating life but may not

¹⁷ Allen, David T. et al. "Measurements of Methane Emissions at Natural Gas Production Sites in the United States." *Proceedings of the National Academy of Sciences of the United States of America* 110.44 (2013): 17768–17773.

¹⁸ Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers. David T. Allen et al. *Environmental Science & Technology* 2015 49 (1), 633-640. DOI: 10.1021/es5040156. Available online at: <http://pubs.acs.org/doi/abs/10.1021/es5040156>

be effective or feasible for other wells or even for the same well at a different point in its operating life. Applicability information was derived from GHGRP subpart W.

- **Install Vapor Recovery Units** – Capex \$50,636, Opex \$9,166, Reduction 95%. These values were based on EPA Gas STAR data, independent ICF analysis, and updates from vendors and industry commenters in both studies.
- **Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps** - Capex \$5,000, Opex \$75, Reduction 100%. These values were based on EPA Gas STAR data with updates from vendors and industry commenters in both studies.
- **Replace Kimray Pumps with Electric Pumps** – Capex \$10,000, Opex \$2,000, Reduction 100%. These values were based on EPA Gas STAR data with updates from vendors and industry commenters in both studies.
- **Pipeline Pump-Down Before Maintenance** – Capex \$0, Opex \$30,155, Reduction 80%. These values were based on EPA Gas STAR data with updates from vendors and industry commenters in both studies. The required equipment is typically leased so there is no Capex.
- **Redesign Blowdown Systems and Alter ESD Practices** - Capex \$15,000, Opex \$0, Reduction 95%. These values were based on EPA Gas STAR data with updates from vendors and industry commenters in both studies.
- **Wet Seal Degassing Recovery System for Centrifugal Compressors** – Capex \$70,000, Opex \$0, reduction 95%. These values were based on EPA Gas STAR data with updates from vendors and industry commenters in both studies.
- **Replace with Instrument Air Systems – Intermittent** – Capex \$60,000, Opex \$17,770, Reduction 100%. These values were based on EPA Gas STAR data with updates from vendors and industry commenters in both studies.
- **LDAR Costs** – The structure of the LDAR cost analysis is different from the other measures, as discussed in the body of the report. The cost analysis structure is based on the regulatory analysis for the Colorado methane rule but most of the values have been updated. The ONE Future sponsors provided extensive input on the labor and instrumentation costs. The baseline labor costs were increased and the number of measurement devices was increased from the Colorado assumptions. The time allocated for inspections was also increased relative to the 2014 EDF report based on input from the sponsors. The baseline emissions were from the EPA Technical Support Document for NSPS OOOO.

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells



Executive Summary

When first completed, many natural gas wells have sufficient reservoir pressure to flow formation fluids (water and liquid hydrocarbon) to the surface along with the produced gas. As gas production continues, the reservoir pressure declines, and as pressure declines, the velocity of the fluid in the well tubing decreases. Eventually, the gas velocity up the production tubing is no longer sufficient to lift liquid droplets to the surface. Liquids accumulate in the tubing, creating additional pressure drop, slowing gas velocity, and raising pressure in the reservoir surrounding the well perforations and inside the casing. As the bottom well pressure approaches reservoir shut-in pressure, gas flow stops and all liquids accumulate at the bottom of the tubing. A common approach to temporarily restore flow is to vent the well to the atmosphere (well “blowdown”), which produces substantial methane emissions. The *U.S. Inventory of Greenhouse Gas Emissions and Sinks 1990–2008* estimates 9.6 billion cubic feet (Bcf) of annual methane emissions from venting of low pressure gas wells.

At different stages in the life of a gas well, various alternatives to repeated well venting can be deployed to move accumulated liquids to the surface. These options include:

- ★ Foaming agents or surfactants
- ★ Velocity tubing
- ★ Plunger lift, operated manually or with ‘smart’ well automation
- ★ Downhole pumps, which include reciprocating (beam) pumps and rotating (progressive cavity) pumps.

Natural Gas STAR Partners report significant methane emission reductions and economic benefits from implementing one or more lift options to remove accumulated liquids in gas wells. Not only are vented methane emissions reduced or eliminated, but these lift techniques can provide the additional benefit of increased gas production.

Economic and Environmental Benefits

Method for Reducing Natural Gas Losses	Volume of Natural Gas Savings and Incremental Production ¹ (Mcf/well/year)	Value of Natural Gas Savings and Additional Production (Mcf/well/year)			Implementation Cost ¹ (2010 \$/Well)	Project Payback (years)		
		\$3 per Mcf	\$5 per Mcf	\$7 per Mcf		\$3 per Mcf	\$5 per Mcf	\$7 per Mcf
Use Foaming Agents	500 – 9,360	\$1,500 - \$28,080	\$2,500 - \$46,800	\$3,500 - \$65,520	\$500 - \$9,880	0 to 7	0 to 4	0 to 3
Install Velocity Tubing	9,285 – 27,610	\$27,855 - \$82,830	\$46,425 - \$138,050	\$64,995 - \$193,270	\$7,000 - \$64,000	0 to 3	0 to 2	0 to 1
“Smart” Well Automated Controls for Plunger Lift²	800 – 1,463 ²	\$2,400 - \$4,389	\$4,000 - \$7,315	\$5,600 - \$10,241	\$5,700 - \$18,000	1 to 8	1 to 5	1 to 4
Install Rod Pumps and Pumping Units²	973 – 2,040 ²	\$2,919 - \$6,120	\$4,865 - \$10,200	\$6,811 - \$14,280	\$41,000 - \$62,000	6 to 22	4 to 13	3 to 10

¹Based on results reported by Natural Gas STAR Partners

²Does not include incremental gas production. Includes only potential gas savings from avoided well venting.

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells

(Cont'd)

By avoiding or reducing well blowdowns, Partners report annual methane emissions savings that range from 500 thousand cubic feet (Mcf) per well to more than 27,000 Mcf/well. The benefit of increased gas production will vary considerably among individual wells and reservoirs, but can be substantial. For example, Partners report that increased gas production following plunger lift installation yielded as much as 18,250 Mcf per well.

Technology Background

Most gas wells will have liquid loading occur at some point during the productive life of the well. When this occurs, a common course of action to improve gas flow includes:

- ★ Shutting-in the well to allow bottom hole pressure to increase,
- ★ Swabbing the well to remove accumulated fluids,
- ★ Venting the well to the atmosphere (well blowdown),
- ★ Installing an artificial lift system.

'No-Emissions' Solutions for Liquid Loading in Gas Wells:

- ★ Foaming Agents/ Surfactants
 - Low cost/ low volume lift method
 - Applied early in production decline, when the bottom hole pressure still generates sufficient velocity to lift liquid droplets
- ★ Velocity Tubing
 - Low maintenance, effective for low volumes lifted
 - Somewhat expensive to acquire and install
 - Often deployed in combination with foaming agents
- ★ Plunger Lift
 - Long lasting
 - Less expense to install and operate than a pumping unit
 - Often, plunger lift cannot produce a well to its economic limit (abandonment).
 - Challenging to operate effectively; requires more time and expertise to manage.
- ★ Rod Pumping Units
 - Can be deployed in applications to remove greater liquid volumes than plunger lift.

Swabbing and “blowing down” a well to temporarily restore production can vent significant methane emissions, from 80 to 1600 Mcf/year per well. The process must be repeated as fluids reaccumulate, resulting in additional methane emissions. Operators may wait until well blowdown becomes increasingly ineffective before implementing some type of artificial lift. At this point, the cumulative methane emissions from a well could be substantial.

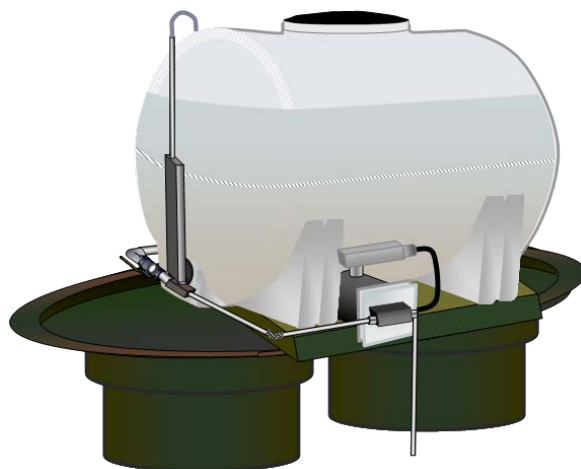
Natural Gas STAR Partners have found that applying artificial lift options early in the life of a well offers significant emissions savings and economic benefits. Each method for lifting liquid in a well has advantages and disadvantages for prolonging the economic life of a well. Total gas savings and methane emission reductions that result from reducing or eliminating well venting will vary for each well depending on flow line operating pressure, reservoir pressure, liquid volume, specific gravity and the number of blowdowns eliminated.

Fluid Removal Options for Gas Wells

Foaming Agents

The use of foam produced by surfactants can be effective for gas wells that accumulate liquid at low rates (Exhibit 1). Foam reduces the density and surface tension of the fluid column, which reduces the critical gas velocity needed to lift fluids to surface and aids liquid removal from the well. Compared to other artificial lift methods, foaming agents are one of the least costly applications for unloading gas wells. Foaming agents work best if the fluid in the well is at least 50 percent water. Surfactants are not

Exhibit 1: Liquid Foaming Agent



Source: S. Bumgardner, Advanced Resources International, inc.

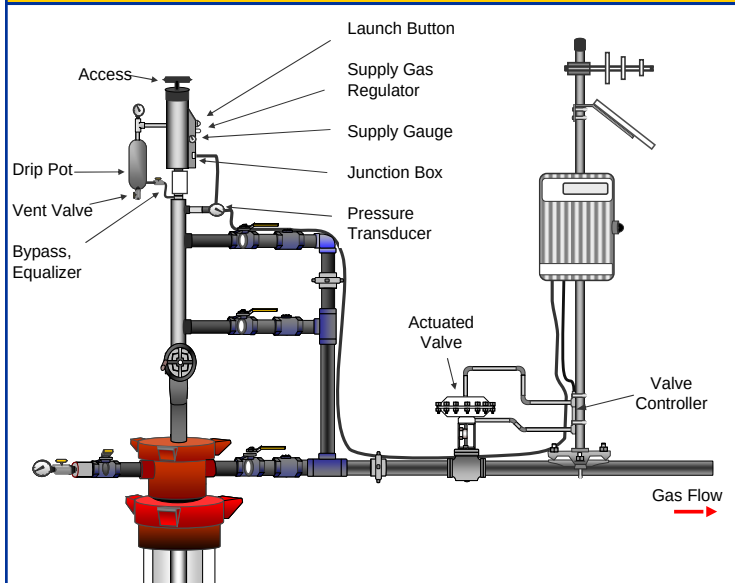
Options for Removing Accumulated Fluid and Improving Flow in Gas Wells

(Cont'd)

effective for natural gas liquids or liquid hydrocarbons.

Surfactants are delivered to the well as soap sticks or as a liquid injected directly into the casing-tubing annulus or down a capillary tubing string. For shallow wells, the surfactant delivery can be as simple as the operator periodically pouring surfactant down the annulus of the well through an open valve. For deep wells, a surfactant injection system requires the installation of surface equipment, as well as regular monitoring. The surface equipment includes a surfactant or 'soap' reservoir, an injection pump, a motor valve with a timer (depending on the installation design), and a power source for the pump (Exhibit 2). No equipment is required in the well, although foaming agents and velocity tubing may be more effective when used in combination.

Exhibit 2: Soap Stick Launcher with Automatic Controller



Source: S. Bumgardner, Advanced Resources International, inc.

Electric pumps can be powered by AC power where available or by solar power to charge batteries. Other pump choices include mechanical pumps that are actuated by the movement of another piece of equipment or pneumatic pumps actuated by gas pressure. Different pump types have different advantages with respect to reliability, precision, remote operation, simplicity, maintenance frequency, efficiency, and equipment compatibility.

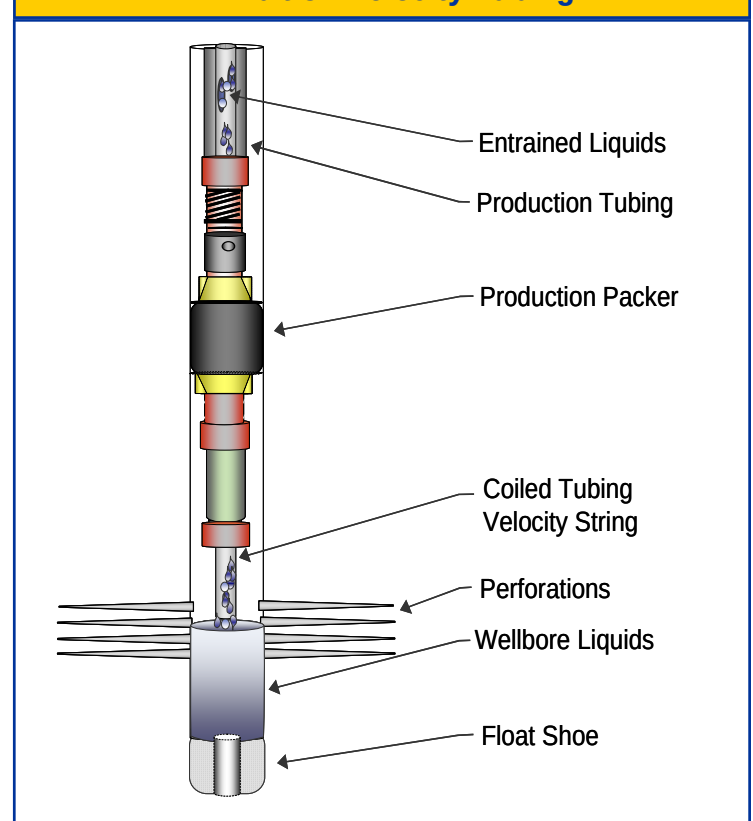
Velocity Tubing

The velocity at which gas flows through pipe determines

the capacity to lift liquids. When the gas flow velocity in a well is not sufficient to move reservoir fluids, the liquids will build up in the well tubing and eventually block gas flow from the reservoir. One option to overcome liquid loading is to install smaller diameter production tubing or 'velocity tubing'. The cross-sectional area of the conduit through which gas is produced determines the velocity of flow and can be critical for controlling liquid loading. A velocity string reduces the cross-sectional area of flow and increases the flow velocity, achieving liquid removal while limiting blowdowns to the atmosphere.

Exhibit 3 shows that the conduit for gas flow up a wellbore can be either production tubing, the casing-tubing annulus or simultaneous flow through both the tubing and the annulus. In any case, a 2004 study estimated that gas velocity must be at least 5 to 10 ft/sec (300 to 600 ft/min) to effectively remove hydrocarbon liquids from a well, and at least 10 to 20 ft/sec (600 to 1200 ft/min) to move produced water. As a rule of thumb, gas flow velocity of 1,000 feet per minute is needed to remove liquid. These figures assume used pipe in good condition with low relative roughness of the pipe wall.

Exhibit 3: Velocity Tubing



Source: S. Bumgardner, Advanced Resources International, inc.

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells

(Cont'd)

The installation of a velocity string is relatively simple and requires calculation of the proper tubing diameter to achieve the required velocity at the inlet and outlet pressures of the tubing. Velocity tubing to facilitate liquid removal can be successfully deployed in low volume gas wells upon initial completion or near the end of their productive lives. Candidate wells include marginal gas wells producing less than 60 Mfcd. Installation of velocity tubing requires a well workover rig to remove the existing production tubing and place the smaller diameter tubing string in the well.

Coiled tubing may also be used, allowing for easier installation and the application of a greater range of tubing diameters as small as 0.25 inches. Coiled tubing can be applied in wells with lower velocity gas production due to better relative roughness characteristics of the tubing and the absence of pipe joint connections. Studies indicate that seamed coiled tubing provides better lift characteristics due to the elimination of turbulence in the flow stream because the seam acts as a “straightening vane”.

Plunger Lift with ‘Smart’ Well Automation

Plunger lifts are commonly used to lift fluids from gas wells. A plunger lift system is a form of intermittent gas lift that uses gas pressure buildup in the casing-tubing annulus to push a steel plunger and a column of fluid above the plunger up the well tubing to the surface. Exhibit 4 shows a conventional plunger lift installation on a gas well.



Source: Chesapeake Energy

The operation of a plunger lift system relies on pressure buildup in a gas well during the time that the well is shut-in (not producing). The well shut-in pressure must significantly exceed the sales line pressure in order to lift the plunger and load of accumulated fluid to the surface against the sales line backpressure. A companion Lessons Learned paper, *Installing Plunger Lift Systems in Gas Wells*, discusses the installation, gas savings and economics of plunger lift systems. The focus of the present Lessons Learned paper are the incremental gas savings obtained from installing ‘smart’ automation systems to better manage the operation of plunger lift installations on a field-wide or basin-wide scale.

Most plunger systems operate on a fixed time cycle or on a preset differential pressure. Regardless of activation system (manual, fixed time cycle, or preset pressure differential), a valve mechanism and controller at the surface cause gas volume and pressure to build up in the wellbore initiating the plunger release cycle. At this point, the surface valve closes and the plunger drops to the bottom of the well. Once adequate pressure is reached, the surface valve opens and the plunger rises to the surface with the liquid load. Insufficient reservoir energy, or too much fluid buildup can overload a plunger lift. When that occurs, venting the well to the atmosphere (well blowdown) instantaneously reduces the backpressure on the plunger and usually allows the plunger to return to the surface.

Automated control systems optimize plunger lift and well unloading operations to prevent overloading (plunger cannot overcome backpressure and rise to the surface) and underloading (plunger rises too quickly, possibly damaging equipment) therefore reducing or eliminating well venting. “Smart” automated control systems combine customized control software with standard well control hardware such as remote terminal units (RTUs) and programmable logic controllers (PLCs) to cycle the plunger system and lift fluids out of the tubing. The artificial intelligence component of a smart automation system monitors the tubing and sales line pressures and allows the PLC to “learn” a well’s performance characteristics (such as flow rate and plunger velocity) and to build an inflow performance relationship (IPR) curve for the well. The frequency and duration of the plunger cycle is then modified to optimize well performance.

Data analysis combined with wellhead control technology is the key to an effective gas well “smart” automation system. A smart automation system stores historical well production data allowing the program to learn from experience by monitoring and analyzing wellhead instrument data. The control system relays wellhead

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells

(Cont'd)

instrument data to a central computer, tracks venting times, and reports well problems and high-venting wells, all of which allow custom management of field production.

The components of a smart well automation system that must be installed on each gas well include:

- ★ remote terminal unit with PLC,
- ★ tubing and casing transmitters,
- ★ gas measurement equipment,
- ★ control valve, and
- ★ plunger detector.

Automated controllers at the wellhead monitor well parameters and adjust plunger cycling. These typically operate on low-voltage, solar batteries. Exhibit 5

Exhibit 5: Typical Wellhead Equipment and Telemetry for Automated Control Systems for Plunger Lift

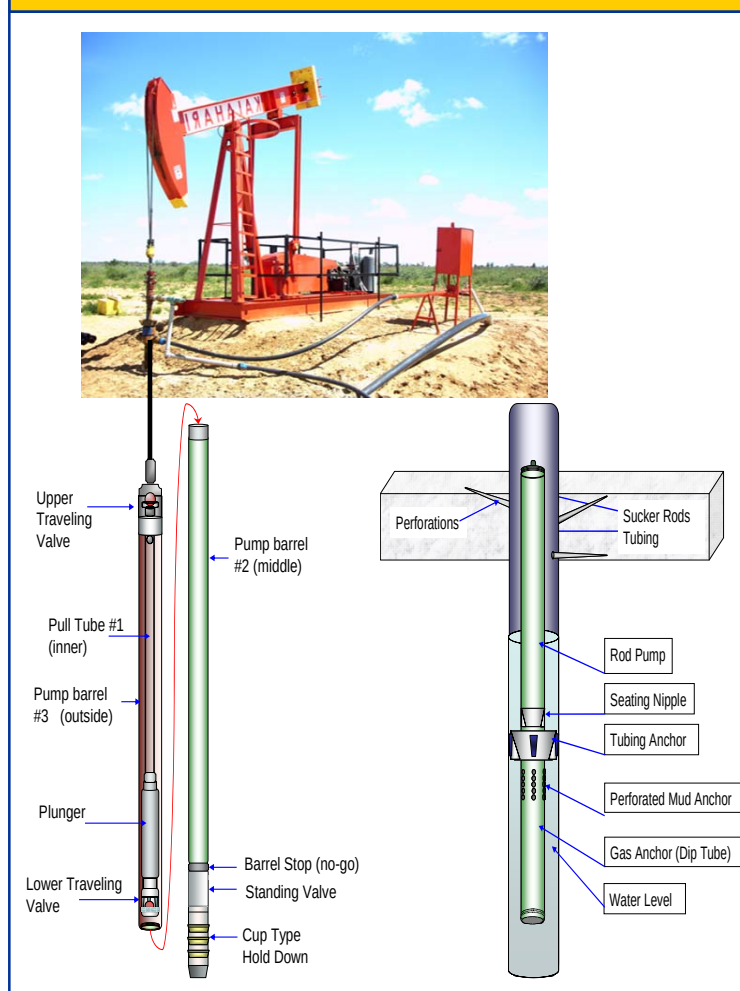


Source: BP

illustrates typical wellhead equipment and telemetry for plunger lift automated control systems. A host system capable of retrieving and presenting data is also required for continuous data logging and remote data transition. Operators configure all controls and send them to the RTU from the host system. Engineering time is needed to customize the control software and optimize the system. Field operating practices and protocols must be flexible to quickly address well performance deficiencies and operating problems.

Partners have found that optimized plunger lift cycling to remove liquids can decrease the amount of gas vented by up to 90+ percent. Methane emission savings from reduced well venting is a significant benefit that can add up to huge volumes when applied on a field or basin scale.

Exhibit 6: Diagram of a Sucker Rod Pump and Pump Jack



Source: S. Bumgardner, Advanced Resources International, inc.

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells

(Cont'd)

Rod Pumps and Pumping Units

A downhole positive displacement, reciprocating rod pump with surface pump unit can be deployed in the later stages of a well's life to remove liquids from the wellbore and maximize production until the well is depleted (Exhibit 6). Pumping units can be installed when there is insufficient reservoir pressure to operate a plunger lift. The units can be manually controlled by the field pumper, or very low volume wells may be operated with a timer.

Pumping units not only eliminate the need to vent the well to unload fluids but also extend the productive life of a well. Methane emissions can be further reduced by operating pumping units with electric motors, rather than natural gas-fueled engines. The annual fuel requirement for a typical pumping unit is approximately 1,500 Mcf per unit, of which 0.5 percent is emitted as unburned methane (8 Mcf per unit per year).

A well workover rig is required to install the downhole rod pump, rods, and tubing in the well. Field personnel must be trained for rod pump operations and proper maintenance of the surface equipment. Excessive wear of the rods and tubing can be a major expense for rod pump applications where solids are produced or down hole corrosion is a problem.

A common problem with reciprocating pumps in gas wells is gas locking of the rod pump valves, which prevents the pump from delivering fluid to the surface at the design rate. The presence of free gas in the subsurface sucker rod pump decreases the volumetric pump efficiency and can prevent the pump from lifting fluid. This is not a problem found in progressive cavity pumps as there are no valves to gas lock.

Economic and Environmental Benefits

Implementation of fluid removal options and artificial lift provide economic and environmentally beneficial alternatives to well blowdown. The major benefit of the

various fluid removal options is extending the productive life of a well. The full scope of environmental and economic benefits depend on the type of artificial lift system and the remaining productive capacity of the well. Several benefits described below, are realized with the progressive application of fluid removal options in gas wells.

- ★ **Improved gas production rates and extended well life.** Fluid removal and artificial lift systems conserve reservoir energy and boost gas production. Regular fluid removal generally extends the economic life of declining wells resulting in more continuous gas production, improved gas production rates, and incremental ultimate recovery.
- ★ **Reclaims vented gas to sales.** Avoiding well blowdown reclaims the value of gas that would otherwise be vented to the atmosphere.
- ★ **Reduced pollution.** Eliminating well blowdown and gas venting eliminates a significant source of methane and other air pollutant emissions.
- ★ **Lower well maintenance costs and fewer remedial treatments.** Overall well maintenance costs can be reduced by eliminating the cost of a workover rig for swabbing wells. Other savings occur when well blowdowns are significantly reduced or eliminated.

Decision Process

The decision to implement any type of liquid removal option during the life-cycle of a gas well should be made when the value of the estimated incremental gas production exceeds the cost of the fluid removal option. When one fluid removal approach becomes ineffective and uneconomic, another can be deployed. If venting a well is the current fluid removal approach, the application of foaming agents, velocity tubing or plunger lift should be evaluated before well blowdowns become too frequent, less effective and costly. Natural Gas STAR Partners can use the following decision process as a guide to evaluate the application, safety, and cost effectiveness of fluid removal and artificial lift installations.

Step 1: Determine the technical feasibility of a fluid removal option or artificial lift installation.

Various data and criteria should be evaluated to select a fluid removal approach that is both technically feasible and cost effective. These data include IPR (inflow

Four Steps for Evaluating Artificial Lift Options:

- Determine the technical feasibility of various artificial lift options.**
- Determine the cost of various options.**
- Estimate the natural gas savings and production increase.**
- Evaluate and compare the economics of artificial lift options.**

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performance relationship) curves; reservoir pressure; gas and fluid production flow rates; fluid levels in the well; the desired flowing bottom hole pressure and casing pressure; production tubing size, the downhole condition of the well; other mechanical limitations of the well and production site; and the capabilities and training of field personnel.

Appendix A (Exhibit A1 and A2) shows the Turner relationship and Lee relationship between critical flow rate (critical gas velocity), and flowing pressure for various sizes of production tubing. If the relationship between flow rate and pressure falls below a line specifying a size of production tubing, a well will not flow liquids to the surface for the indicated tubing size. If flow rate vs pressure falls on or above the line for a specified tubing size, a well meets or exceeds the critical flow rate for the specified tubing size and the well is able to unload fluid to the surface. Exhibits A1 and A2 can be used as starting points to estimate whether a fluid removal or artificial lift option is likely to be effective. Following are some technical considerations that enter into the decision process for each fluid removal option:

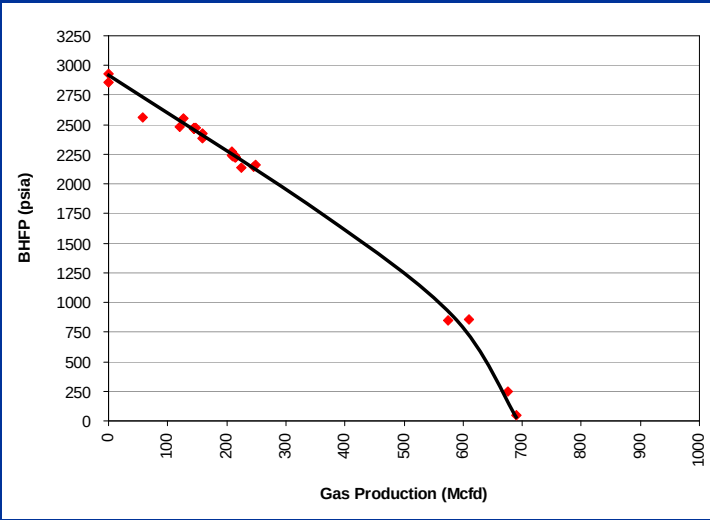
- ★ **Foaming Agents.** Partners typically use foaming agents early in the life of gas wells when the wells begin to load with formation water and the liquid production rate is comparatively low. Foaming works best if the liquid in the wellbore is mainly water, and condensate content is less than 50 percent. Foaming agents may also be used in combination with other well treatments that reduce salt and scale build up, or may be applied in combination with velocity tubing.
- ★ **Velocity Tubing.** Velocity tubing strings are appropriate for natural gas wells with relatively small liquid production and higher reservoir pressure. Low surface pipeline pressure relative to the reservoir pressure is also necessary to create the

pressure drop that will achieve an adequate flow rate. The depth of the well affects the overall cost of the installation, but is usually offset by the higher pressure and gas volume in deeper wells. Velocity tubing can also be a good option for deviated wells and crooked well bores. Rod pumped wells with deviation and or dog legs that become uneconomic due to high failure rates and servicing costs may also be candidates for velocity strings.

Determining the feasibility of installing a velocity tubing string is relatively straightforward. An inflow performance relationship (IPR curve) is calculated to establish the flow regime in the well tubing, as shown in Exhibit 7. The diagram shown in Exhibit 7 illustrates the relationship between gas production and the bottom hole flowing pressure (BHFP). Gas flow is evaluated and the velocity relationships for various sizes of tubing are developed to determine the appropriate diameter for use in each well. As a rule of thumb, a gas flow velocity of approximately 1,000 feet per minute is the minimum necessary to remove fresh water. Condensate requires less velocity due to its lower density while more dense brine requires a higher velocity.

Once the velocity string is installed, no other artificial lift equipment is required until the reservoir pressure declines to the point that

Exhibit 7: Example of Inflow Performance Relationship Curve for Evaluating Fluid Removal Options



Source: S. Bumgardner, Advanced Resources International, inc.

Indicators of Liquid Loading in Gas Wells:

1. Construct an IPR curve and evaluate the production efficiency of the well.
2. Monitor production curves for each well on a regular basis. Liquid loading is indicated if the curve for a normally declining well becomes erratic and the production rate drops.
3. Compute the critical gas velocity (flow rate) at which liquid can no longer be lifted in the tubing (see Appendix)
4. Critical velocity vs. flowing tubing pressure can be constructed for various tubing diameters.

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velocities of 1,000 feet per minute are no longer possible in the tubing. The introduction of a foaming agent to the bottom of a tubing string will extend the effective life of a velocity string below the 1,000 feet per minute velocity required to lift water by reducing the density of the column that is lifted. This only applies to water lifted from the well tubing since condensate is not affected by a surfactant.

- ★ **"Smart" Well Automation of Plunger Lift.** Candidate wells for plunger lift generally do not have adequate downhole pressure for the well to flow freely into a gas gathering system. Like pumping units, plunger lifts are used to extend the productive life of a well. Installation is less expensive than rod pumps, but plunger lifts may be difficult to operate.

Conventional plunger lift operations rely upon manual, on-site adjustments to tune a plunger cycle time. When a plunger lift becomes overloaded, the well must be manually vented to the atmosphere to restart the plunger. A "smart" well automation system enhances plunger performance by monitoring parameters such as tubing and casing pressure, well flow rate and plunger cycle frequency (travel time). Data for each well are relayed to a host computer where operators review the data and address any performance deficiencies or operating problems. This helps to optimize plunger lift performance, improve gas production, and reduce well venting.

Optimum plunger lift performance generally occurs when the plunger cycle is frequent and set to lift the smallest liquid loads. Small liquid loads require lower operating bottom hole pressure, which allows for better inflow performance. As with velocity tubing, a desirable velocity for a plunger to ascend in tubing is in the range of 500 to 1,000 ft per minute.

- ★ **Pumping Units.** Rod pump installations for gas wells can be costly to install and operate, but can extend well life, increase ultimate recovery, increase profits and reduce methane emissions. A rod pumping application for gas wells must be carefully designed to ensure trouble-free installation of the pumping units, minimize installation costs, and maximize operating cost savings by reducing mechanical wear and the need for well servicing.

Technical considerations for a rod pump application include the amount of pump capacity required, the pump setting depth in the well, and the type and

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

gravity of the fluid in the hole (brine, fresh water, hydrocarbon, hydrogen sulfide, carbon dioxide, etc.). These factors influence the components of a rod pump installation, including rod pump materials, rod string size and grade, pumping unit design, size of the prime mover (motor), pump speed and stroke length. Resources available for evaluating and designing rod pump applications for gas wells include American Petroleum Institute and various Society of Petroleum Engineers publications; commercial pumping unit vendors; and computer design models. In general, rod pump installations for gas wells have lower fluid volumes than for oil wells. Operating costs can be minimized by correctly sizing the artificial lift and pumping as slow as possible while maintaining a pumped-off condition. The use of pump-off controllers are also effective by matching the pump displacement to the volume of fluid entering the well bore.

Step 2. Determine the cost of fluid removal options.

Costs associated with the various fluid removal options include capital, start-up and labor expenditures to purchase and install the equipment, as well as ongoing costs to operate and maintain the systems.

- ★ **Foaming Agents.** Partners report upfront capital and start-up costs to install soap launchers ranging from \$500 to \$3,880 per well. Monthly cost for the foaming agent is \$500 per well, or approximately \$6,000 per year. As such, typical costs can vary between \$500 and \$9,880.
- ★ **Velocity Tubing.** One Partner reports total capital and installation costs of at least \$25,000 per well, which includes the workover rig time, downhole tools, tubing connections and supervision. Another Partner has deployed velocity tubing in more than 100 wells and reports total installation costs ranging from \$8,100 per well to \$30,000 per well. Based on Partner experiences, typical costs will vary between \$7,000 and \$64,000 per well.

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★ **“Smart” Well Automation of Plunger Lift.** Two Partners report implementing “smart” automation systems to control plunger lift operations. One operation is fairly small, consisting of 21 wells. The second is a basin-wide deployment on more than 2,150 wells. Reported upfront costs for the smaller installation is \$6,300 per well. Total cost over 5 years reported for the larger automation project is \$12,200,000 or approximately \$5,700 per well. Typical costs will vary between \$5,700 and \$18,000 depending on the complexity of the “smart” automation system. These costs would be incremental over the cost of installing a plunger lift system.

★ **Pumping Units.** Capital and installation costs include the use of a workover rig and crew, for approximately one day, sucker rods, rod guides and pump costs, and the cost of the pumping unit and motor. Other start-up costs can include miscellaneous clean out operations to prepare the well to receive a down hole pump and sucker rods.

Partners report that location preparation, well clean out, artificial lift equipment, and a pumping unit can be installed for approximately \$41,000 to \$62,000 per well. The reported average cost of the pumping unit alone appears to range from approximately \$17,000 to \$27,000. Most companies have surplus units in stock that can be deployed at the expense of transportation and repair, or may purchase used units.

Step 3. Estimate the savings from various fluid removal options.

The total savings associated with any of the fluid removal and artificial lift options include:

- ★ Revenue from incremental increased gas production;
- ★ Revenue from avoided emissions;
- ★ Additional avoided costs such as well treatment and workover costs, and reduced fuel and electricity;
- ★ Salvage value.

Revenue from Increased Production

The most significant benefit of deploying foaming agents, velocity tubing or a pumping unit is to extend the productive life of the well by decreasing the abandonment

pressure of the reservoir and increasing the cumulative gas production. The benefit of automating a plunger lift system is to optimize the plunger cycle. Most of the increase in gas production is realized by the initial decision to install plunger lifts. Installing a ‘smart’ automated control system provides some incremental increase in gas production over a plunger lift system operated manually or by a timer, but the most significant benefit is the emissions avoided from repeated well blowdowns and the reduction in personnel time required at the well.

The fluid removal options are evaluated based on the incremental gas production predicted by well blowdowns. For wells that are not on production decline, the incremental gas production from installing velocity tubing or artificial lift can be estimated by assuming the average peak production after a well blowdown event represents the incremental peak production that will be achieved after the fluid removal option is implemented in the well.

The more common evaluation is for a well already experiencing production decline. In such a case, estimating incremental gas production from implementing a fluid removal/ artificial lift method is more complex and requires generating a new “expected” production and decline curve that would result from reducing the back pressure at the well perforations. This requires well-specific reservoir engineering analyses, a basic example of which is provided in Appendix B.

Once the incremental gas production from implementing a fluid removal approach is estimated, operators can

Exhibit 8: Gas Production Increase from Application of Foaming Agents — One Partner’s Experience

- One Gas STAR Partner reports injecting foaming agent into 15 wells using soap sticks.
- Incremental gas production of individual wells increased an average of 513 Mcf per well per year.
- Annual incremental gas production for the entire project was 7,700 Mcf.
- Total cost for the project was \$8,871 in 2010 dollars.
- At nominal gas prices ranging from \$3.00/ Mcf to \$5.00/ Mcf, the value incremental gas production ranges from approximately \$23,100 to \$38,500/ year and project payback occurs in 3 to 5 months.

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calculate the value of the incremental gas and estimate the economics of the application. Exhibit 8 is an example of the potential revenue from increased gas production using foaming agents. Note that Exhibit 8 does not include other benefits such as avoided blowdown emissions and operations cost savings.

Revenue from Avoided Emissions

Emissions from venting gas to the atmosphere vary in both frequency and flow rates, and are entirely well and reservoir specific. The volume of natural gas emissions avoided by reducing or eliminating well blow-downs will vary due to individual characteristics such as sales line pressure, well shut-in pressure, fluid accumulation rate, and well dimensions (such as depth and casing and tubing diameters). Another key variable is an operator's normal practice for venting wells. Some operators put wells on automatic vent timers. Some wells are vented manually with personnel standing by monitoring the blow-down. In some cases, wells are open to vent and unattended for hours or days, depending upon the time it typically takes the well to clear liquids. The economic benefits of avoided emissions will vary considerably, and some projects will have significantly shorter payback periods than others.

Partner-reported annual emissions attributable to well blowdowns vary from 1 Mcf per well to several thousand Mcf per well, so methane emissions savings attributable to

avoided emissions will also vary according to the characteristics and available data for the particular wells being vented. Exhibit 9 illustrates the range of avoided emissions reported by various Partners after applying specific fluid removal and artificial lift strategies in their operations.

Revenue from avoided emissions can be calculated by multiplying the sales price of the gas by the volume of vented gas. If well emissions have not been measured, they can be estimated. The volume of emissions from well venting can be estimated by constructing an IPR curve to predict the open flow potential of the well based on reservoir pressure, depth, tubular sizes, and fluid constituents. Other operator methods are discussed in Appendix C. The volume of gas released during well blow-down is dependent on the duration of the event, wellhead temperature and pressure, size of the vent line, the properties of the gas, and the quantity of water produced.

Four approaches to estimating well blow-down emissions are provided in Appendix C. None of the estimations discussed in Appendix C provide the "exact" result in an absolute sense, but they are accurate enough for effective management of producing gas wells. One emission estimation approach calculates well blow-down volume as a function of venting time, normal production rate, well volume and gas properties. Another approach uses

Exhibit 9: Comparison of Partner-Reported Costs and Emissions Savings for Fluid Removal / Artificial Lift Options

Fluid Removal Approach	Installation Costs (\$/well)	Incremental Gas Production (Mcf/well/year)	Avoided Methane Emissions from Swabbing/ Blowdown ² (Mcf/Well/Year)	Other Potential Cost Savings (\$/well)
Use Foaming Agents	\$500 - \$9,880 (installation of soap launcher); \$500/month (surfactant)	365 – 1,095	178 – 7,394	\$2,000 (eliminate well swabbing)
Install Velocity Tubing	\$7,000 - \$64,000	9,125 – 18,250	146 – 7,394	\$2,000 - \$13,200 (eliminate well swabbing & blowdown)
"Smart" Well Automated Controls for Plunger Lift¹	Partner reported average cost = \$5,700 - \$18,000	Not reported by Partners (5,000 Mcf estimated for average U.S. gas well by assuming a 10-20% increase in production)	Partner reported = 630 – 900 (500 Mcf estimated for average U.S. well by assuming 1 % of annual production)	\$7,500 (reduces labor cost to monitor plunger lift installations in the field)
Install Rod Pumps and Pumping Units	\$41,000 - \$62,000	Not reported	769 – 1,612	\$22,994 (salvage value at end of well life)

¹Incremental cost, gas production and methane emissions savings for installation of automated plunger lift control system.

²Assumes methane content of natural gas at wellhead is 79 percent, unless reported otherwise.

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pressure transient analysis to extrapolate gas flow rate from wellhead pressure. A final approach installs an orifice meter on a vent line and measures specific vent volume over time. The resulting vent rates expressed in Mcf/minute are averaged by producing formation and extrapolated from the initial subset of wells measured to the larger well population.

Avoided Costs and Other Benefits

Avoided costs and additional benefits depend on the type of fluid removal/ artificial lift system currently applied in the well and the new system to be deployed. These can include avoided chemical treatments, fewer well workovers, lower fuel costs and lower daily operations and maintenance costs. Partners report using foaming agents to replace well swabbing for a savings of approximately \$2,000 annually per well. EPA's Natural Gas STAR Partners report that "smart" well automated control systems for plunger lifts have reduced the labor cost for field monitoring by approximately \$7,500 per well. Velocity tubing eliminates well swabbing, well blowdowns and chemical treatments, the cost of which are reported to range from a few thousand to more than \$13,000 per treatment.

Step 4. Evaluate the economics of fluid removal options.

Basic cash flow analysis can be used to compare the costs and benefits of the various fluid removal options. Exhibit 9 is a summary of the installation costs, gas savings and reduced methane losses associated with each fluid removal

approach that have been reported by Natural Gas STAR Partners. Cash flow analyses based on Partner-reported experience and data are provided in Exhibit 10 for installing velocity tubing strings and in Exhibit 11 for "smart" well automated control systems for plunger lift.

Partner Experience

This section highlights specific experiences reported by Gas STAR Partners with the selected fluid removal options for gas wells.

Install Velocity Tubing Strings.

One Partner reported installation of velocity tubing in two Gulf Coast wells during 2008. Total installation cost in 2008 was \$25,000 per well, which included a workover rig to remove and replace tubing, downhole tools, connections and supervision. Due to low inflation between years 2008 and 2010, the installation cost in 2010 dollars is only slightly higher than 2008.

The velocity tubing installation in these wells improved gas production by 25 Mcfd to 50 Mcfd, which equates to annual incremental gas production of approximately 9,125 Mcf to 18,250 Mcf per well. In addition, gas savings from eliminating well swabbing is 160 Mcf per year per well. Methane content of gas at the well head is 91 percent, so the estimated reduction in methane losses are 146 Mcf per well. Velocity tubing also eliminated annual swabbing costs of approximately \$2000 per well per year. Exhibit 10

Exhibit 10: Economic Analysis of Velocity Tubing Installation Replacing Periodic Swabbing

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Value of Gas from Increased Production¹		\$36,500	\$36,500	\$36,500	\$36,500	\$36,500
Value of Gas from Avoided Emissions²		\$640	\$640	\$640	\$640	\$640
Velocity Tubing Installation Cost	(\$25,000)					
Avoided Swabbing Cost		\$2,000	\$2,000	\$2,000	\$2,000	\$2,000
Net Annual Cash Flow	(\$25,000)	\$39,140	\$39,140	\$39,140	\$39,140	\$39,140
Internal Rate of Return = 155% NPV (Net Present Value)³ = \$112,156 Payback Period = 8 months						

¹ Gas valued at \$4.00/ Mcf for 9,125 Mcf/well (25 Mcfd) due to increased gas production

² Gas valued at \$4.00/Mcf for 160 Mcf /well of avoided gas emissions due to elimination of well swabbing

³ Net present value based on 10 percent discount rate over 5 years

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(Cont'd)

provides a cash flow analysis of this Partner's velocity tubing installation replacing well swabbing.

Install "Smart" Automated Control Systems on Plunger Lifts

Two Partners have applied "smart" well automated control systems at plunger lift installations. One Partner—BP—initiated an automation project in 2000, and in 2001 began installing automated plunger lift control systems across their San Juan Basin operations. BP justified the project based on gas and methane emissions savings resulting from a 50 percent reduction in well venting between 2000 and 2004. By 2007, BP implemented automated control systems for more than 2,150 wells equipped with plunger lift which resulted in average methane emissions savings of 900 Mcf per well. Total cost for the "smart" automation systems was \$12.2 million. Total gas venting was reduced from approximately 4 billion cubic feet of gas per year (Bcf) to approximately 0.8 Bcf.

Another Natural Gas STAR Partner found that a substantially smaller application of "smart" automated controls for plunger lift can be similarly effective. An automated control system was implemented for 21 wells equipped with plunger lifts. Total gas savings are 16,800 Mcf per year, or 800 Mcf per well. Assuming a methane content of 79 percent, estimated annual methane emissions savings are 632 Mcf per well.

The wide range in upfront capital and installation costs for components of plunger lift automated control systems are indicated in Exhibit 9. The host computer and communication system can be quite costly (\$50,000 to \$750,000) depending upon the size of the project, but as more plunger lift-equipped wells are added, the unit cost for the automated control system is significantly reduced. The two Natural Gas STAR Partners report approximate unit costs for plunger lift automated control systems of \$6,800 and \$5,950 per well, respectively. Exhibit 11 provides a basic cash flow analysis of "smart" well automated control systems for plunger lift based on

Exhibit 11: Economic Analysis of "Smart" Well Automated Control Systems for Plunger Lift for Hypothetical Onshore Gas Field¹

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Value of Gas from Increased Production²		\$220,000	\$220,000	\$220,000	\$220,000	\$220,000
Value of Gas from Avoided Emissions³		\$40,000	\$40,000	\$40,000	\$40,000	\$40,000
Install RTUs at Wells, \$ (\$11,000/well x 20 wells)	(\$220,000)					
Install Host Computer / Communication (\$50K - - \$750K)	(\$200,000)					
Avoided Labor Cost for Field Monitoring (\$7500/well x 20 wells)		\$150,000	\$150,000	\$150,000	\$150,000	\$150,000
Net Cash Inflow	(\$420,000)	\$410,000	\$410,000	\$410,000	\$410,000	\$410,000
Internal Rate of Return = 94 % NPV (Net Present Value)⁴ = \$1,031,111 Payback Period = 12.3months						

¹ Assumes production from average US gas well is 50,000 Mcf/Year

² Gas valued at \$4.00/Mcf for 5,000 Mcf /well of increased gas production due to optimized plunger lift operation; equivalent to 10% of production for average US onshore gas well. Assumes 20 wells in project.

³ Gas valued at \$4.00/Mcf for 500 Mcf of gas savings due to reduced well blowdown/venting; equivalent to 1% of production for average US onshore gas well. Assumes 20 wells in project.

⁴ Net present value based on 10 percent discount rate over 5 years

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generic assumptions about potential increased gas production and methane emissions savings for the average onshore natural gas well in the United States.

Install Pumping Units on Wells Lifting Low Water Volumes

ConocoPhillips installed pumping units on 45 low-pressure gas wells in 2003 to remove low water volumes from the wells and prevent them from loading up. This installation eliminated routine venting of the wells for up to one hour per day. The primary benefit of installing pumping units on these wells is the incremental gas production gained by extending the productive life of the wells. The Partner reported gas savings of 973 Mcf per well from the elimination of well blowdowns as a secondary, but not insignificant, benefit. The pump jacks at this installation are powered by electric motors rather than natural gas engines, which contributes to fewer methane emissions and lower maintenance costs.

ConocoPhillips reported total gas savings of 43,780 Mcf for the project or approximately 973 Mcf per well per year. At a nominal gas price of \$4.00 to \$5.00/Mcf, this corresponds to savings of approximately \$3,892 to \$4,865 per unit, or \$175,140 to \$218,900 per year for the entire project consisting of 45 wells. Assuming a methane content of 79 percent, this project has reduced methane losses by 34,586 Mcf per year.

Total capital and installation costs for the downhole pumps and surface pumping units were estimated to be \$62,000 per well in 2003 or the equivalent of \$73,332 in 2010 dollars. The total cost in 2003 included \$45,000 for

site preparation, downhole equipment, and installation plus an average cost of \$17,000 per pumping unit. The project was expanded in subsequent years. ConocoPhillips reported a total of 100 pumping units installed from 2005 through 2007. During this time, the average reported upfront installation cost declined to approximately \$38,000 per unit in 2010 dollars. Assuming a nominal gas price of \$4, the vented gas savings alone pays back the typical pumping unit installation for this project in less than 10 years.

Lessons Learned

- ★ For natural gas wells, a progression of fluid removal options are available to unload accumulated fluid, boost gas production, extend well life and reduce or eliminate the need for well venting.
- ★ Options for removing accumulated wellbore fluids from gas wells range from relatively low cost application of surfactants, appropriate for wells with low fluid production and significant remaining reservoir energy, to installing pumping units and downhole rod pumps on wells with depleted reservoir pressure and significant water production.
- ★ The best approach will depend on the where a well is performing along the continuum of its productive life.
- ★ Well blowdown and swabbing can release large volumes of natural gas to the atmosphere, producing significant methane emissions and gas losses.
- ★ Fluid removal approaches presented in this paper can reduce the amount of remedial work needed during the lifetime of a well, eliminate well blowdowns, and increase the ultimate recovery of the well while minimizing methane emissions to the atmosphere.
- ★ If a well is in production decline, the fluid removal alternatives discussed here will increase gas production in most cases or at least arrest the decline.
- ★ This increased gas production should be captured in analyses of cash flow and future economic benefit when evaluating fluid removal options for gas wells. In most cases, increased gas production is the primary benefit from implementing any or all of the fluid removal options.

Nelson Price Indexes

In order to account for inflation in equipment and operating & maintenance costs, Nelson-Farrar Quarterly Cost Indexes (available in the first issue of each quarter in the *Oil and Gas Journal*) are used to update costs in the Lessons Learned documents.

The "Refinery Operation Index" is used to revise operating costs while the "Machinery: Oilfield Itemized Refining Cost Index" is used to update equipment costs.

To use these indexes in the future, simply look up the most current Nelson-Farrar index number, divide by the February 2006 Nelson-Farrar index number, and, finally multiply by the appropriate costs in the Lessons Learned.

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- ★ Methane emissions and gas savings from the elimination of well venting is generally a secondary, but significant, benefit, which may cover all or most of the upfront installation costs for a fluid removal technology.

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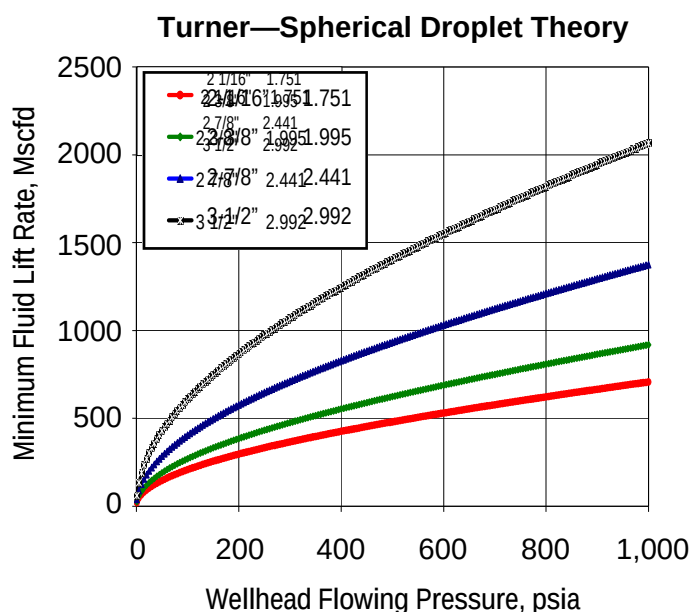
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Options for Removing Accumulated Fluid and Improving Flow in Gas Wells

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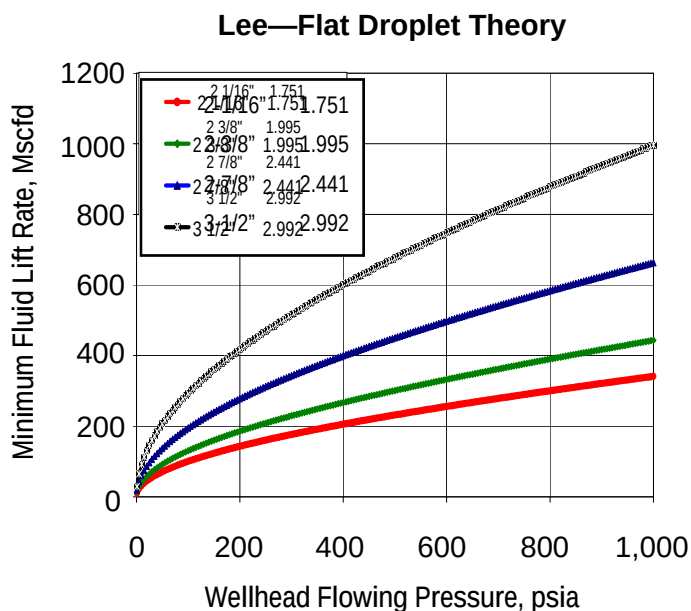
APPENDIX A: Estimating the Critical Flow Rate to Remove Liquids from Production Tubing

Exhibit A1: Turner Unloading Rate for Well Producing Water



Source: S. Bumgardner, Advanced Resources International, inc.

Exhibit A2: Lee Unloading Rate for Well Producing Water



Source: S. Bumgardner, Advanced Resources International, inc.

APPENDIX B: Estimating Incremental Production for Declining Wells

From Dake's Fundamentals of Reservoir Engineering (1978) the following analytical model can be used to estimate increased gas flow into a well in response to reducing back pressure on the perforations by removing accumulated liquids. The semi-steady state inflow equation is:

$$m(p_{avg}) - m(p_{wf}) = \left[\frac{(1422 \times Q \times T)}{(k \times h)} \right] \times [\ln(r_e/r_w) - 3/4 + S] \quad (8.15)$$

Where,

$m(p_{avg})$ = real gas pseudo pressure average

$m(p_{wf})$ = real gas pseudo pressure well flowing

Q = gas production rate

T = absolute temperature

k = permeability

h = formation height

r_e = external boundary radius

r_w = wellbore radius

S = mechanical skin factor

Incremental production achieved by implementing various artificial lift options can be estimated by solving this equation for 'Q' calculated for retarded flow with fluids in the hole (current conditions and current decline curve), and comparing to 'Q' calculated for the condition of no fluids in the hole (artificial lift active and improved decline curve). This discussion is intended as a guide for estimating the potential impact of fluid removal alternatives, and is not a substitute for thorough reservoir engineering analyses of specific wells.

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells

(Cont'd)

APPENDIX C: Alternate Techniques for Estimating Avoided Emissions When Replacing Blowdowns

Simple Vent Volume Calculation

A conservative estimate of well venting volumes can be made using the following equation:

$$\text{Annual Vent Volume, Mscf/yr} = (0.37 \times 10^{-6}) * (\text{Casing Diameter}^2) * (\text{Well Depth}) * (\text{Shut-in Pressure}) * (\# \text{ of Annual Vents})$$

Where, casing diameter is in inches, well depth is in feet and shut-in pressure is in psia. If the shut-in pressure is not known, a suitable surrogate is the casing pressure at the surface.

This is the minimum volume of gas that would be vented to atmospheric pressure from a well that has stopped flowing to the sales line because a head of liquid has accumulated in the tubing equal to the pressure difference between the sales line pressure and well shut-in pressure.

If the well shut-in pressure is more than 1.5 times the sales line pressure, as required for a plunger lift installation, then the volume of gas in the well casing at shut-in pressure should be minimally sufficient to push the liquid in the tubing to the surface in slug-flow when back-pressure is reduced to sales line pressure.

Partners can estimate the minimum time needed to vent the well by using this volume and the Weymouth gas-flow formula (worked out for common pipe diameters, lengths and pressure drops in Tables 3, 4 and 5 in *Pipeline Rules of Thumb Handbook*, Fourth Edition, pages 283 and 284). If a Partner's practice is to open and vent the wells for a longer time than calculated by these methods, the Annual Vent Volume calculated by this equation can be scaled up according to the ratio of the actual vent time versus the minimum vent time calculated using the Weymouth equation.

Natural Gas STAR Partner, BP, has reported three approaches to estimating well venting and completion emissions, which include: 1) a more detailed version of the vent volume calculation method above, 2) pressure transient analysis, and 3) installing an orifice meter on the vent line.

Detailed Vent Volume Calculation

The detailed vent volume calculation is a function of

venting time, normal production rate, and “well blowdown value” that represents the volume of gas in a well under an assumption of line pressure.

$$\text{Vent Volume (Mcf)} = ((\text{Vent Time} - 30 \text{ min}) * (1/1440) * \text{Production Rate}) + (\text{Well Blowdown Volume})$$

$$\text{Well Blowdown Volume (Mcf)} = (\text{well depth} * 3.1416 * (\text{casing diameter}/2)^2 * ((\text{tubing press} + \text{atmospheric press})/14.7) * (520/(\text{Temp}+460)) / Z / 1000$$

Variables:

- production rate, Mcf per day
- well depth, ft
- atmospheric pressure, psia
- shut-in tubing pressure, psig
- temperature of gas in pipeline, °F
- diameter of production casing, ft
- compressibility, Z

A limitation of the vent volume calculation method is that it does not account for either the volume or weight of a column of fluid in the wellbore at the time of venting.

Pressure Transient Analysis

This method is based on observations of wellhead pressure versus flow rate for a specific set of wells which are used to develop a linear expression of gas flow rate versus wellhead pressure. This relationship is then applied to pressure transient data during blowdown to extrapolate Mcf versus time for the venting period. All data are evaluated using pressure data analysis software to extrapolate total vented volumes based on the blowdown time, pipe diameter and the decline in well head pressure during the process. An advantage of this approach is that it accounts for choke flow and is tailored to specific wells. Limitations of the approach are that it fails to account for very large influx into the reservoir and the observations data set may not be representative of the formation. To make the data set more representative, it is recommended that the data include at least one point within the following 5 ranges:

- ★ $P \leq 25$ psia
- ★ $25 \text{ psia} < P \leq 60 \text{ psia}$

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells (Cont'd)

- ★ $60 \text{ psia} < P \leq 110 \text{ psia}$
- ★ $110 \text{ psia} < P \leq 200 \text{ psia}$
- ★ $200 \text{ psia} < P$

Orifice Metering of Blow Down

For this approach, an orifice meter is installed on a vent line and flow rates are measured directly during blowdown. An advantage of this approach is the precision of the data that are obtained, potentially offering meaningful comparisons of vent volumes between well types, well completions or producing formations.

A limitation of the approach is that results obtained from a 'study population' or small subset of producing wells will likely be extrapolated to a larger field or producing area, and the original study wells may not be representative of field operations as a whole.

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells

(Cont'd)



**United States
Environmental Protection Agency
Air and Radiation (6202J)
1200 Pennsylvania Ave., NW
Washington, DC 20460**

2011

EPA provides the suggested methane emissions estimating methods contained in this document as a tool to develop basic methane emissions estimates only. As regulatory reporting demands a higher-level of accuracy, the methane emission estimating methods and terminology contained in this document may not conform to the Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart W methods or those in other EPA regulations.

Installing Plunger Lift Systems In Gas Wells



Executive Summary

In mature gas wells, the accumulation of fluids in the well can impede and sometimes halt gas production. Gas flow is maintained by removing accumulated fluids through the use of a beam pump or remedial treatments, such as swabbing, soaping, or venting the well to atmospheric pressure (referred to as “blowing down” the well). Fluid removal operations, particularly well blowdowns, may result in substantial methane emissions to the atmosphere.

Installing a plunger lift system is a cost-effective alternative for removing liquids. Plunger lift systems have the additional benefit of increasing production, as well as significantly reducing methane emissions associated with blowdown operations. A plunger lift uses gas pressure buildup in a well to lift a column of accumulated fluid out of the well. The plunger lift system helps to maintain gas production and may reduce the need for other remedial operations.

Natural Gas STAR Partners report significant economic benefits and methane emission reductions from installing plunger lift systems in gas wells. Companies have reported annual gas savings averaging 600 thousand cubic feet (Mcf) per well by avoiding blowdowns. In addition, increased gas production following plunger lift installation has yielded total gas benefits of up to 18,250 Mcf per well, worth an estimated \$127,750. Benefits from both increased gas production and emissions savings are well- and reservoir-specific and will vary considerably.

Technology Background

Liquid loading of the wellbore is often a serious problem in aging production wells. Operators commonly use beam lift pumps or remedial techniques, such as venting or “blowing down” the well to atmospheric pressure, to remove liquid buildup and restore well productivity. These techniques, however, result in gas losses. In the case of blowing down a well, the process must be repeated over time as fluids reaccumulate, resulting in additional methane emissions.

Plunger lift systems are a cost-effective alternative to both beam lifts and well blowdowns and can significantly reduce gas losses, eliminate or reduce the frequency of future well treatments, and improve well productivity. A plunger lift system is a form of intermittent gas lift that uses gas pressure buildup in the casing-tubing annulus to push a steel plunger, and the column of fluid ahead of it, up the well tubing to the surface. The plunger serves as a piston between the liquid and the gas, which minimizes liquid fallback, and as a scale and paraffin scraper. Exhibit 1 depicts a typical plunger lift system.

The operation of a plunger lift system relies on the natural buildup of pressure in a gas well during the time that the well is shut-in (not producing). The well shut-in pressure must be sufficiently higher than the sales-line pressure to lift the plunger and liquid load to the surface. A valve mechanism, controlled by a microprocessor, regulates gas input to the casing and automates the process. The controller is normally powered by a solar recharged battery and can be a simple timer-cycle or have solid state

Economic and Environmental Benefits

Method for Reducing Natural Gas Losses	Potential Gas Savings from Increased Gas Production and Avoided Emissions (Mcf)	Value of Natural Gas Production and Savings (\$)			Implementation Cost (\$)	Payback (Months)		
		\$3 per Mcf	\$5 per Mcf	\$7 per Mcf		\$3 per Mcf	\$5 per Mcf	\$7 per Mcf
Install a Plunger Lift System	4,700 - 18,250 ^a per year per well	\$14,100 - \$54,750 per year	\$23,500 - \$91,250 per year	\$32,900 - \$127,750 per year	\$2,591 - \$10,363 per year per well	1 - 9	1 - 6	1 - 4

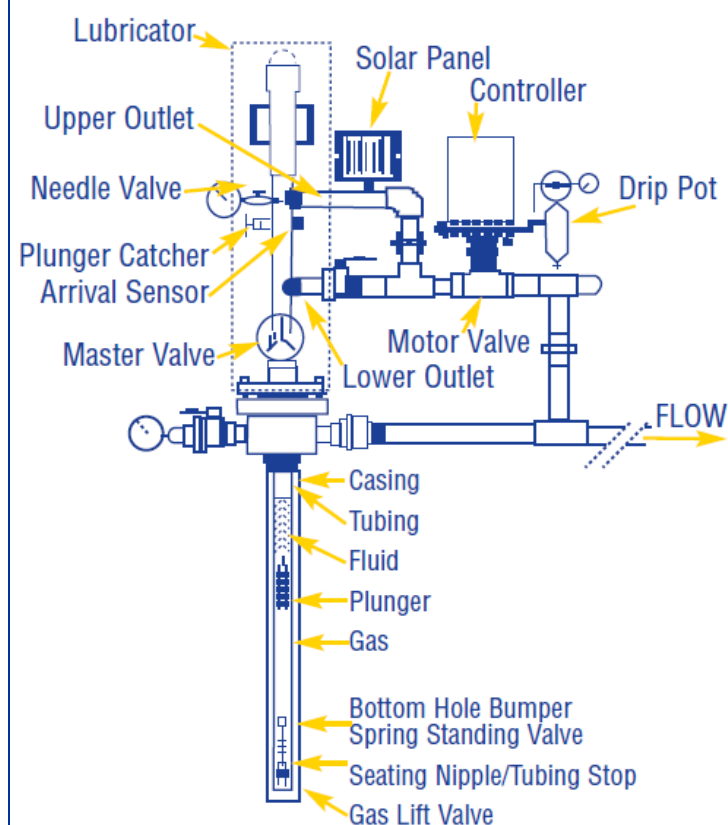
General Assumptions:

^a Based on results reported by Natural Gas STAR Partners.

Installing Plunger Lift Systems In Gas Wells

(Cont'd)

Exhibit 1: Plunger Lifts



memory and programmable functions based on process sensors.

Operation of a typical plunger lift system involves the following steps:

1. The plunger rests on the bottom hole bumper spring located at the base of the well. As gas is produced to the sales line, liquids accumulate in the well-bore, creating a gradual increase in backpressure that slows gas production.
2. To reverse the decline in gas production, the well is shut-in at the surface by an automatic controller. This causes well pressure to increase as a large volume of high pressure gas accumulates in the annulus between the casing and tubing. Once a sufficient volume of gas and pressure is obtained, the plunger and liquid load are pushed to the surface.

3. As the plunger is lifted to the surface, gas and accumulated liquids above the plunger flow through the upper and lower outlets.
4. The plunger arrives and is captured in the lubricator, situated across the upper lubricator outlet.
5. The gas that has lifted the plunger flows through the lower outlet to the sales line.
6. Once gas flow is stabilized, the automatic controller releases the plunger, dropping it back down the tubing.
7. The cycle repeats.

New information technology systems have streamlined plunger lift monitoring and control. For example, technologies such as smart automation, online data management and satellite communications allow operators to control plunger lift systems remotely, without regular field visits. Operators visit only the wells that need attention, which increases efficiency and reduces cost. For more information regarding this technology and other artificial lift systems, see the Lessons Learned document titled "Options for Removing Accumulated Fluid and Improving Flow in Gas Wells".

Economic and Environmental Benefits

The installation of a plunger lift system serves as a cost-effective alternative to beam lifts and well blowdown and yields significant economic and environmental benefits. The extent and nature of these benefits depend on the liquid removal system that the plunger lift is replacing.

- ★ **Lower capital cost versus installing beam lift equipment.** The costs of installing and maintaining a plunger lift are generally lower than the cost to install and maintain beam lift equipment.
- ★ **Lower well maintenance and fewer remedial treatments.** Overall well maintenance costs are reduced because periodic remedial treatments such as swabbing or well blowdowns are reduced or no longer needed with plunger lift systems.
- ★ **Continuous production improves gas production rates and increases efficiency.** Plunger lift systems can conserve the well's lifting energy and increase gas production. Regular fluid

Installing Plunger Lift Systems In Gas Wells

(Cont'd)

removal allows the well to produce gas continuously and prevent fluid loading that periodically halts gas production or “kills” the well. Often, the continuous removal of fluids results in daily gas production rates that are higher than the production rates prior to the plunger lift installation.

- ★ **Reduced paraffin and scale buildup.** In wells where paraffin or scale buildup is a problem, the mechanical action of the plunger running up and down the tubing may prevent particulate buildup inside the tubing. Thus, the need for chemical or swabbing treatments may be reduced or eliminated. Many different types of plungers are manufactured with “wobble-washers” to improve their “scraping” performance.
- ★ **Lower methane emissions.** Eliminating repetitive remedial treatments and well workovers also reduces methane emissions. Natural Gas STAR Partners have reported annual gas savings averaging 600 Mcf per well by avoiding blowdown and an average of 30 Mcf per year by eliminating workovers.
- ★ **Other economic benefits.** In calculating the economic benefits of plunger lifts, the savings from avoided emissions are only one of many factors to consider in the analysis. Additional savings may result from the salvage value of surplus production equipment and the associated reduction in electricity and work over costs. Moreover, wells that move water continuously out of the well bore have the potential to produce more condensate and oil.

Decision Process

Operators should evaluate plunger lifts as an alternative to well blowdown and beam lift equipment. The decision to install a plunger lift system must be made on a case-by-case basis. Partners can use the following decision process as a guide to evaluate the applicability and cost-effectiveness of plunger lift systems for their gas production wells.

Step 1: Determine the technical feasibility of a plunger lift installation.

Plunger lifts are applicable in gas wells that experience liquid loading and have sufficient gas volume and excess shut-in pressure to lift the liquids from the reservoir to the surface. Exhibit 2 lists four common well characteristics that are good indicators of plunger lift applicability. Vendors often will supply written materials designed to

Four Steps for Evaluating Plunger Lift Systems:

1. Determine the technical feasibility of a plunger lift installation;
2. Determine the cost of a plunger lift system;
3. Estimate the savings of a plunger lift; and
4. Evaluate the plunger lift's economics.

help operators ascertain whether a particular well would benefit from the installation of a plunger lift system. As an example, a well that is 3,000 feet deep, producing to a sales line at 100 psig, has a shut-in pressure of 150 psig and must be vented to the atmosphere daily to expel and average of three barrels per day of water accumulation. This well has sufficient excess shut-in pressure and would have to produce 3,600 scf per day (400 scf/bbl/1000 feet of depth times 3000 feet of depth, times 3 barrels of water per day) to justify use of a plunger lift.

Exhibit 2: Common Requirements for Plunger Lift Applications

- ★ Well blowdowns and other fluid removal techniques are necessary to maintain production.
- ★ Wells must produce at least 400 scf of gas per barrel of fluid per 1,000 feet of depth.
- ★ Wells with shut-in wellhead pressure that is 1.5 times the sales line pressure.
- ★ Wells with scale or paraffin buildup.

Step 2: Determine the cost of a plunger lift system.

Costs associated with plunger lifts include capital, start-up and labor expenditures to purchase and install the equipment, as well as ongoing costs to operate and maintain the system. These costs include:

- ★ **Capital, installation, and start-up costs.** The basic plunger lift installation costs approximately \$1,900 to \$7,800. In contrast, installation of surface pumping equipment, such as a beam lift, costs between \$26,000 and \$52,000. Plunger lift installation costs include installing the piping, valves, controller and power supply on the wellhead and setting the down-hole plunger bumper assembly assuming the well tubing is open and clear. The largest variable in the installation cost is running a wire-line to gauge the tubing (check for internal blockages) and test run a plunger from top to bottom (broaching) to assure that the plunger will move freely up and down the tubing string. Other start-up costs can include a well depth survey, swabbing to

Installing Plunger Lift Systems In Gas Wells

(Cont'd)

Nelson Price Indexes

In order to account for inflation in equipment and operating & maintenance costs, Nelson-Farrar Quarterly Cost Indexes (available in the first issue of each quarter in the *Oil and Gas Journal*) are used to update costs in the Lessons Learned documents.

The "Refinery Operation Index" is used to revise operating costs while the "Machinery: Oilfield Itemized Refining Cost Index" is used to update equipment costs.

To use these indexes in the future, simply look up the most current Nelson-Farrar index number, divide by the February 2006 Nelson-Farrar index number, and, finally multiply by the appropriate costs in the Lessons Learned.

remove well bore fluids, acidizing to remove mineral scale and clean out perforations, fishing-out debris in the well, and other miscellaneous well clean out operations. These additional start-up costs can range from \$700 to more than \$2,600.

Operators considering a plunger lift installation should note that the system requires continuous tubing string with a constant internal diameter in good condition. The replacement of the tubing string, if required, can add several thousands of dollars more to the cost of installation, depending upon the depth of the well.

- ★ **Operating costs.** Plunger lift maintenance requires routine inspection of the lubricator and plunger. Typically, these items need to be replaced every 6 to 12 months, at an approximate cost of \$700 to \$1,300 per year. Other system components are inspected annually.

Step 3: Estimate the savings of a plunger lift.

The savings associated with a plunger lift include:

- ★ Revenue from increased production;
- ★ Revenue from avoided emissions;
- ★ Additional avoided costs—well treatment costs, reduced electricity costs, workover costs; and
- ★ Salvage value.

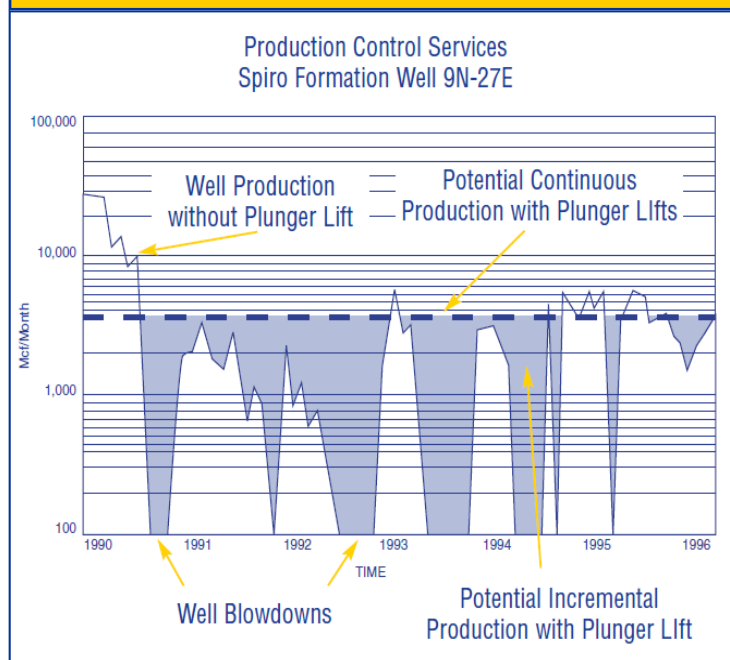
Revenue from Increased Production

The most significant benefit of plunger lift installations is the resulting increase in gas production. During the decision process, the increase in production cannot be measured directly and must be estimated. The methodology for estimating this expected incremental production varies depending on the state of the well. The methodology for continuous or non-declining wells is relatively straightforward. In contrast, the methodology for estimating the incremental production for wells in decline is more complex.

- ★ **Estimating incremental gas production for non-declining wells.** The incremental gas production from a plunger lift installation may be estimated by assuming that the average peak production rate achieved after blowdown is near the potential peak production rate for the well with fluid removed. A well log, like that illustrated in Exhibit 3, can be used to estimate the potential production increase.

In this exhibit, the solid line shows well production rate gradually, then steeply declining as liquids accumulate in the tubing. Production is restored by venting the well to the atmosphere, but then declines again with reaccumulation of liquids. Note that the production rate scale, in thousands of cubic feet per month, is a log scale. The dashed line shows the

Exhibit 3: Incremental Production for Non-Declining Wells



Installing Plunger Lift Systems In Gas Wells

(Cont'd)

average peak production rate after liquids unloading. This is assumed to be equal to the potential peak production rate that could be achieved with a plunger lift system, typically at least 80 percent of the peak production rate after blowdown. The shaded area between the potential production (dashed-line) and the actual well production (solid-line) represents the estimate of incremental increase in gas production that can be achieved with a plunger lift system.

- ★ **Estimating incremental production for declining wells or for situations in which the maximum production level after blowdown is not known.** Wells that are in decline or operated without periodic blowdowns require more detailed methods for estimating incremental production under plunger lift systems. Plunger lift installations on declining wells, for example, will require generating an improved declining curve resulting from decreased pressure at perforations. Operators should seek the assistance of a reservoir engineer to aid in these determinations (see Appendix).

Once incremental production from a plunger lift installation is estimated, operators can calculate the value of incremental gas and estimate the economics of the plunger lift installation. Exhibit 4 presents an example of potential financial returns at different levels of increase in gas production. It is important to recognize that local costs and conditions may vary. Note also that the example in Exhibit 4 does not take

into account other financial benefits of a plunger lift installation project, such as avoided emissions and decreased electricity and chemical treatment costs, which are described later in this Lessons Learned. Consideration of these additional benefits may improve the already excellent financial returns of a plunger lift installation.

Revenue from Avoided Emissions

The amount of natural gas emissions reduced following plunger lift installation will vary greatly from well to well, based on the individual well and reservoir characteristics such as sales line pressure, well shut-in pressure, liquids accumulation rate, and well dimensions (depth, casing diameter, tubing diameter). The most important variable, however, is the normal operating practice of venting wells. Some operators put wells on automatic vent timers, while others manually vent the wells with the operator standing by monitoring the vent, and still others open the well vent and leave, returning in hours or up to days, depending on how long it typically takes the well to clear liquids. Thus, the economic benefits from avoided emissions will also vary considerably. Such wide variability means that some projects will have much shorter payback periods than others. While most plunger lift installations will be justified by increased gas production rates alone, methane emissions reductions can provide an additional revenue stream.

- ★ **Avoided emissions when replacing blowdowns.** In wells where plunger lift systems are installed, emissions from blowing down the well can be reduced. Blowdown emissions vary widely in both their frequency and flow rates and are entirely well and reservoir specific. Emissions attributable to blowdown activities have been reported from 1 Mcf per year to thousands of Mcf per year per well. Therefore, the savings attributable to avoided emissions will vary greatly based on the data for the particular well being rehailed.

Revenue from avoided emissions can be calculated by multiplying the market value of the gas by the volume of avoided emissions. If the emissions per well per blowdown have not been measured, they must be estimated. In the example below, the amount of gas that is vented from a low pressure gas well at each blowdown is estimated as 0.5625 times the sustained flow gas rate. This emission factor assumes that the integrated average flow over the blowdown period is 56.25 percent of full well flow. Using this assumption, Exhibit 5 demonstrates that

Exhibit 4: Example of Estimated Financial Returns for Various Levels of Incremental Gas Production from a Plunger Installation

Incremental Gas Production (Mcf/d)	Payout Time (months)	Internal Rate of Return (%)
3	14	71
5	8	141
10	4	309
15	3	475
20	2	640
25	2	804
30	2	969

Assumptions:
Value of gas = \$7.00/Mcf.
Plunger system cost of \$7,772 including start-up cost.
Lease operating expense of \$790/year.
Production decline of 6%/year.

Source: Production Control Services, Inc.

Installing Plunger Lift Systems In Gas Wells

(Cont'd)

for an unloaded well producing 100 Mcf per day, the gas vented to the atmosphere can be estimated at 2 Mcf per hour of blowdown.

Exhibit 5: Example—Estimate Avoided Emissions from Blowdowns

Avoided Emissions per Hour of Blowdown ^a	= (0.56251 x Sustained Daily Flow Rate) / 24 hrs/day
Avoided Emissions ^b	= (0.5625 x 100 Mcfd) / 24 = 2 Mcf per hour of blowdown
Annual Value of Avoided Emissions ^c	= 2 Mcf x 12 x \$7.00/Mcf = \$168 per year

^a Recommended methane emission factor reported in the joint GRI/EPA study, Methane Emissions From the Natural Gas Industry, Volume 7: Blow and Purge Activities (June 1995). The study estimated that at the beginning of a blowdown event, gas flow is restricted by fluids in the well to 25 percent of full flow. By the end of the blowdown event, gas flow is returned to 100 percent. The integrated average flow over the blowdown period is 56.25 percent of full well flow.

^b Assuming a sustained daily production rate of 100 Mcfd.

^c Assuming 1 blowdown per month lasting 1 hour.

This method is simple to use, but anecdotal evidence suggests that it produces estimates of methane emissions avoided that are unrealistically low. For an alternate method for estimating avoided emissions from blowdowns, see the Appendix.

Given the high degree of variability in emissions based on well and reservoir specific characteristics, measurement is the preferred method for determining avoided emissions. Field measurements can provide the data necessary to accurately determine the savings attributable to avoided emissions.

★ Avoided emissions when replacing beam lifts.

In cases where plunger lifts replace beam lifts rather than blowdowns, emissions will be avoided due to reduced workovers for mechanical repairs, to remove debris and cleanout perforations, to remove mineral scale and paraffin deposits from the sucker rods. The average emissions associated with workovers have been reported as approximately 2 Mcf per workover; the frequency of workovers has been reported to range from 1 to 15 per year. Due to well-specific characteristics such as flow during workover, duration of workover, and frequency of workover, avoided emissions can vary greatly.

Avoided Costs and Additional Benefits

Avoided costs depend on the type of liquid removal systems currently in place, but can include avoided well treatment, reduced electricity costs, and reduced workover costs.

Avoided well treatment costs are applicable when plunger lifts replace beam lifts or other remedial techniques such as blowdown, swabbing, or soaping. Reduced electricity costs, reduced workovers, and recovered salvage value are only applicable if plunger lifts replace beam lifts.

★ **Avoided well treatment costs.** Well treatment costs include chemical treatments, microbial cleanups, and removal of rods and scraping the borehole. Information from shallow 1,500-foot wells show well remediation costs including rod removal and tubing rehabilitation at more than \$14,500 per well. Chemical treatment costs (inhibitors, solvents, dispersants, hot fluids, crystal modifiers, and surfactants) are reported in the literature at a minimum of \$13,200 per well per year. Microbial costs to reduce paraffin have been shown to be \$6,600 per well per year (note that microbial treatments do not address the fluids influx problem). Each of these treatment costs increases as the severity of the scale or paraffin increases, and as the depth of the well increases.

★ **Reduced electricity costs compared to beam lifts.** Reduced electric operating costs further increase the economic return of plunger lifts. No electrical costs are associated with plunger lifts, because most controllers are solar-powered with battery backup. Exhibit 6 presents a range of avoided electricity costs reported by operators who have installed plunger lifts. Assuming 365 days of operation, avoided electricity costs range from \$1,000 to \$7,300 per year.

★ **Reduced workover costs compared to beam lifts.** Workover costs associated with beam lifts have been reported as \$1,300 per day. While typical

Exhibit 6: Electricity Costs^a Avoided by Using a Plunger Lift in Place of a Beam Lift

Motor Size (BHP)	Operation Cost (\$/day)
10	3
20	7
30	10
40	13
50	17
60	20

^a Electricity cost assumes 50 percent of full load, running 50 percent of the time, with cost of 7.5 cents/kWh.

Installing Plunger Lift Systems In Gas Wells

(Cont'd)

workovers may take one day, wells more than 8,000 feet deep will require more than one day of workover time. Depending on the well, from 1 to 15 workovers can be required per year. These costs are avoided by using a plunger lift.

- ★ **Recovered salvage value when replacing a beam lift.** If the plunger being installed is replacing a beam lift, extra income and a better economic return are realized from the salvage value of the old production hardware. Exhibit 7 shows the salvage value that may be obtained by selling the surplus pumping units. In some cases, salvage sales alone may pay for the installation of plunger lifts.

Exhibit 7: Salvage Value^a of Legacy Equipment When Converting from Beam Lift to Plunger Lift Operations

Capital Savings from Salvaging Equipment

Size of Pumping Unit (inch-lbs torque)	Equipment Salvage Value (\$)
114,000	12,300
160,000	16,800
228,000	21,300
320,000	27,200
456,000	34,300
640,000	41,500

^a Salvage costs include low estimate sale value of pumping unit, electric motor, and rod string.

Step 4: Evaluate the plunger lift's economics.

A basic cash flow analysis can be used to compare the costs and benefits of a plunger lift with other liquid removal options. Exhibit 8 shows a summary of the costs associated with each option.

- ★ **Economics of Replacing a Beam Lift with a Plunger Lift.** In Exhibit 9 the data from Exhibit 8 is used to model a hypothetical 100 Mcfd well and to evaluate the economics of plunger lift installation. The increase in production is 20 Mcf per day, yielding an annual increase in production of 7,300 Mcf. Assuming one workover per year prior to installation, the switch to a plunger lift also provides 2 Mcf of avoided emissions per year. The project profits

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

greatly from the salvage value of the surplus beam lift equipment, yielding an immediate payback. Even if the salvage value is not recovered, the project may yield payback after only a few months depending on the well's productivity.

- ★ **Economics of Avoiding Blowdown with a Plunger Lift.** Exhibit 10 uses data from Exhibit 8 to evaluate the economics of a hypothetical 100 Mcfd well at which a plunger lift is installed to replace blowdown as the method for removing liquid from the well. Assuming the increased production is 20 Mcf per day, the annual increase in production is 7,300 Mcf. In addition, there will be savings from avoided emissions during blowdown. Assuming 12 one-hour blowdowns per year, the avoided emissions are 24 Mcf per year.

Exhibit 8: Cost Comparison of Plunger Lift vs. Other Options

Cost Category	Plunger Lift	Traditional Beam Lift	Remedial Treatment ^a
Capital and Startup Costs	\$1,943 - \$7,772	\$25,907 - \$51,813	\$0
Implementation Costs:			
Maintenance ^b	\$1,300/yr	\$1,300 - \$19,500/yr	\$0
Well Treatment ^c	\$0	\$13,200+	\$13,200+
Electrical ^d	\$0	\$1,000 - \$7,300/yr	\$0
Salvage	\$0	(\$12,000 - \$41,500)	\$0

^a Includes soaping, swabbing, and blowing down.

^b For traditional beam lift, maintenance costs include workovers and assume 1 to 15 workovers per year at \$1,300 per workover.

^c Costs may vary depending on the nature of the liquid.

^d Electricity costs for plunger lift: assume the lift is solar and well powered.

Installing Plunger Lift Systems In Gas Wells

(Cont'd)

Exhibit 9: Economic Analysis of Plunger Lift Replacing a Beam Lift

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Value of Gas from Increased Production and Avoided Emissions ^a		\$51,114	\$51,114	\$51,114	\$51,114	\$51,114
Plunger Lift Equipment and Setup Cost	(\$7,772)					
Plunger Lift Maintenance		(\$1,300)	(\$1,300)	(\$1,300)	(\$1,300)	(\$1,300)
Electric Cost per Year	\$0	\$0	\$0	\$0	\$0	\$0
Salvage Value Beam Lift Equipment	\$21,300					
Avoided Beam Lift Maintenance (1 workover/yr)		\$1,300	\$1,300	\$1,300	\$1,300	\$1,300
Avoided Beam Lift Electricity Costs (10HP motor)		\$1,000	\$1,000	\$1,000	\$1,000	\$1,000
Avoided Chemical Treatments		\$13,200	\$13,200	\$13,200	\$13,200	\$13,200
Net Cash Inflow	\$13,528	\$65,314	\$65,314	\$65,314	\$65,314	\$65,314
NPV (Net Present Value)^b = \$261,119 Payback Period = Immediate						
^a Gas valued at \$7.00 per Mcf for 7,300 Mcf due to increased production and 2 Mcf from avoided emissions per event (based on 1 workover per year). ^b Net present value based on 10 percent discount rate over 5 years.						

Exhibit 10: Economic Analysis of Plunger Lift Replacing Blowdown

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Value of Gas from Increased Production and Avoided Emissions ^a		\$51,268	\$51,268	\$51,268	\$51,268	\$51,268
Plunger Lift Equipment and Setup Cost	\$(7,772)					
Plunger Lift Maintenance		(\$1,300)	(\$1,300)	(\$1,300)	(\$1,300)	(\$1,300)
Electric Cost per Year	\$0	\$0	\$0	\$0	\$0	\$0
Avoided Chemical Treatments		\$13,200	\$13,200	\$13,200	\$13,200	\$13,200
Net Cash Inflow	(\$7,772)	\$63,168	\$63,168	\$63,168	\$63,168	\$63,168
NPV (Net Present Value)^b = \$231,684 Payback Period = 2 months						
^a Gas valued at \$7.00 per Mcf for 7,300 Mcf due to increased production and 24 Mcf from avoided emissions per event (based on 12 blowdowns per year and 2 Mcf per blowdown). ^b Net present value based on 10 percent discount rate over 5 years.						

Installing Plunger Lift Systems In Gas Wells

(Cont'd)

When assessing options for installing plunger lift systems on gas wells, natural gas price may influence the decision making process. Exhibit 11 shows an economic analysis of installing a plunger lift system rather than blowing down a well to the atmosphere to lift accumulated fluid at different natural gas prices.

Exhibit 11: Gas Price Impact on Economic Analysis

	\$3/Mcf	\$5/Mcf	\$7/Mcf	\$8/Mcf	\$10/Mcf
Value of Gas Saved	\$21,972	\$36,620	\$51,268	\$58,592	\$73,240
Payback Period (months)	3	2	2	2	2
Internal Rate of Return (IRR)	436%	624%	813%	907%	1095%
Net Present Value (i=10%)	\$120,630	\$176,157	\$231,684	\$259,448	\$314,976

Case Studies

BP (formerly Amoco) Midland Farm Field

Amoco Corporation, a Natural Gas STAR charter Partner (now merged with BP), documented its success in replacing beam lift, rod pump well production equipment with plunger lifts at its Midland Farm field. Prior to installing plunger lift systems, Amoco used beam lift installations with fiberglass rod strings. The lift equipment was primarily 640 inch-lb pumping units powered by 60 HP motors. Operations personnel noted that wells at the field were having problems with paraffin plating the well bore and sucker rods, which blocked fluid flow and interfered with fiberglass sucker rod movement. Plunger lifts were seen as a possible solution to inhibit the accumulation of paraffin downhole.

Amoco began its plunger lift replacement program with a single-well pilot project. Based on the success of this initial effort, Amoco then expanded the replacement process to the entire field. As a result of the success in the Midland Farm field, Amoco installed 190 plunger lift units

at its Denver City and Sundown, Texas locations, replacing other beam lift applications.

Costs and Benefits

Amoco estimated that plunger lift system installation costs—including plunger equipment and tubing conversion costs—averaged \$13,000 per well (initial pilot costs were higher than average during the learning phase, and the cost of tubing conversion is included).

Amoco then calculated savings resulting from avoided costs in three areas—electricity, workover, and chemical treatment. Overall, Amoco estimated that the avoided costs of electricity, workover, and paraffin control averaged \$24,000 per well per year.

- ★ **Electricity.** Cost savings were estimated based on 50 percent run times. Using the costs from Exhibit 6, the estimated electrical cost savings were estimated to be \$20 per day.
- ★ **Workover.** On average, Amoco had one workover per year per well to fix rod parts. With the old beam lift systems, the cost of this operation was \$4,000, averaging about \$11 per day.
- ★ **Chemical treatment.** The biggest savings were realized from avoided chemical treatment. Amoco was able to save the approximately \$13,000 per well per year for paraffin control because the plunger operation removed paraffin accumulation in the tubing.

Increased Gas Production and Revenue

For the initial plunger lift installation, Amoco realized an increase in gas production of more than 400 Mcf per day. Upon expansion of the plunger lift installation to the entire field, the company realized notable success in many wells—although some showed little or no production increase during the 30 day evaluation period. Total production increase (including both incremental production and non-emitted gas) across all wells where plunger lifts were installed was 1,348 Mcf per day. The average annual gas savings, which assumes a 6 percent production decline, was 11,274 Mcf per well or approximately \$78,918 per well at 2006 prices. Exhibit 12 and Exhibit 13 summarize the initial results and first year economics of Amoco's Midland Farm plunger lift installation. In addition to the gas savings and cost savings from the plunger lift installations, Amoco realized a one-time gain from the sale of surplus pumping units

Installing Plunger Lift Systems In Gas Wells

(Cont'd)

Exhibit 12: Change in Production Rates due to Plunger Lift Installation in Midland Farm Field, Texas

^a Well #	Production Before Plunger Lift			Production 30 Days After Installation		
	Gas (Mcf/d)	Oil (Bpd)	Water (Bpd)	Gas (Mcf/d)	Oil (Bpd)	Water (Bpd)
1	233	6	1	676	5	1
2	280	15	1	345	15	1
3	240	13	2	531	33	11
4	180	12	2	180	16	3
5	250	5	2	500	5	2
6	95	8	2	75	12	0
7	125	13	1	125	14	0
8	55	6	1	55	13	2
9	120	45	6	175	40	0
10	160	16	3	334	17	3
11	180	7	12	80	6	6
12	215	15	4	388	21	2
13	122	8	8	124	12	7
14	88	5	10	23	9	1
Avg.	167	12	4	258	16	3

^a All wells approximately 11,400 feet deep.

Source: World Oil, November, 1995.

Exhibit 13: BP Economics of Plunger Lifts Replacing Beam Lifts

Average Annual Gas Savings ^a (Mcf/year)	Value of Gas Saved per Year ^b	Plunger Lift Installation Cost per Well	Avoided Rod Workover Cost per Well per Year	Avoided Chemical Treatment per Well per Year	Avoided Electrical Costs per Well per Day	Average Savings per Well ^c	Additional Salvage Value of Beam Lift per Well
11,274	\$78,918	\$13,000	\$4,000	\$13,000	\$20	\$90,200	\$41,500

^a Average initial gas production = 1,348 Mcfd. Assumes 6 percent annual production decline.

^b Gas valued at \$7.00 per Mcf.

^c Value saved is averaged over 14 wells.

Installing Plunger Lift Systems In Gas Wells

(Cont'd)

and motors, resulting in additional revenue of \$41,500 per installation.

Analysis

A summary of the costs and benefits associated with Amoco's plunger lift installation program is provided below in Exhibit 13. For the first year of operation, the company realized an average annual savings of approximately \$90,200 per well at 2006 prices. In addition the company realized approximately \$41,500 per well from salvage of the beam lift equipment at 2006 costs.

ExxonMobil Big Piney Field

At Big Piney Field in Wyoming, Natural Gas STAR charter Partner Mobil Oil Corporation (now merged with Exxon) has installed plunger lift systems at 19 wells. The first two plunger lifts were installed in 1995, and the remaining wells were equipped in 1997. As a result of these installations, Mobil reduced overall blowdown gas emissions by 12,164 Mcf per year. In addition to the methane emission reduction, the plunger lift system reduced the venting of ethane (6 percent by volume), C3 hydrocarbons + VOCs (5 percent), and inerts (2 percent). Exhibit 14 shows the emission reductions for each well after plunger lift installation.

Installation Tips

The following suggestions can help ensure trouble-free installation of a plunger lift system:

- ★ **Do not use a completion packer, because it limits the amount of gas production per plunger trip.** Without a completion packer, the entire annular void space is available to create a large compressed gas supply. The greater the volume of gas, the larger the volume of water that can be lifted.
- ★ **Check for tubing obstructions with a gauge ring before installation.** Tubing obstructions hinder plunger movement and may require replacement of production tubing.
- ★ **Capture the plunger after the first trip.** Inspection of the plunger for the presence of any damage, sand, or scale will help prevent any subsequent plunger lift operational difficulties, permitting immediate operational repair while the crew and installation equipment are mobilized.

Lessons Learned

Plunger lift systems offer several advantages over other remedial treatments for removing reservoir fluids from wells: increased gas sales, increased well life, decreased well maintenance, and decreased methane emissions. The following should be considered when installing a plunger lift system:

- ★ Plunger lift installations can offer quick paybacks and high return on investments whether replacing a beam lift or blowdowns.
- ★ Plunger lift installations can greatly reduce the amount of remedial work needed throughout the

**Exhibit 14: Plunger Lift Program
at Big Piney, Wyoming**

Well #	Pre-Plunger Emission Volume (Mcf/yr/well)	Post-Plunger Emission Volume (Mcf/yr/well)	Annualized Reduction (Mcf/yr/well)
1	1,456	0	1,456
2	581	0	581
3	1,959	318	1,641
4	924	0	924
5	105	24	81
6	263	95	168
7	713	80	633
8	753	0	753
9	333	0	333
10	765	217	548
11	1,442	129	1,313
12	1,175	991	184
13	694	215	479
14	1,416	1,259	157
15	1,132	708	424
16	1,940	561	1,379
17	731	461	270
18	246	0	246
19	594	0	594
Totals	17,222	5,058	12,164

Installing Plunger Lift Systems In Gas Wells

(Cont'd)

lifetime of the well and the amount of methane vented to the atmosphere.

- ★ An economic analysis of plunger lift installation should include the incremental boost in productivity as well as the associated extension in well life.
- ★ Even when the well pressure declines below that necessary to lift the plunger and liquids against sales line back pressure, a plunger is more efficient in removing liquids with the well vented to the atmosphere than simply blowing the well without a plunger lift.
- ★ Include methane emission reductions from installing plunger lift systems in annual reports submitted as part of the Natural Gas STAR Program.

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Installing Plunger Lift Systems In Gas Wells

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Appendix

Estimating incremental production for declining wells.

From Dake's *Fundamentals of Reservoir Engineering* (1982) we can use the following equation to calculate the increase in downhole flow for reduced pressure that may be seen when using a plunger lift. A semi-steady state inflow equation can be expressed as:

$$m(p_{avg}) - m(p_{wf}) = [(1422 \times Q \times T)/(k \times h)] \times [\ln(r_e/r_w) - 3/4 + S] \times (8.15)$$

Where,

$m(p_{avg})$ = real gas pseudo pressure average

$m(p_{wf})$ = real gas pseudo pressure well flowing

Q = gas production rate

T = absolute temperature

k = permeability

h = formation height

r_e = external boundary radius

r_w = wellbore radius

S = mechanical skin factor

After the reservoir parameters are gathered, this equation can be solved for Q for the retarded flow with fluids in the hole (current conditions and current decline curve), and Q for no fluids in the hole (plunger lift active and improved decline curve). This is a guideline, and operators are reminded to use a reservoir engineer to aid in this determination.

Alternate technique for calculating avoided emissions when replacing blowdowns.

A conservative estimate of well venting volumes can be made using the following equation:

$$\text{Annual Vent Volume, Mscf/yr} = (0.37 \times 10^{-6}) \times (\text{Casing Diameter})^2 \times \text{Well Depth} \times \text{Shut-in Pressure} \times \text{Annual Vents}$$

Where casing diameter is in inches, well depth is in feet

and shut-in pressure is in psig. Exhibit A1 shows an example calculation.

Exhibit A1: Example—Estimate Avoided Emissions from Blowdowns	
Casing Diameter	8 inches
Well Depth	10,000 feet
Shut-in Pressure	214.7 psig
Annual Vents	52 (weekly venting)
Annual Vent Volume = $(0.37 \times 10^{-6}) \times 8^2 \times 10,000 \times 214.7 \times 52 = 2,644$ Mscf/yr	

This is the minimum volume of gas that would be vented to atmospheric pressure from a well that has stopped flowing to the sales line because a head of liquid has accumulated in the tubing equal to the pressure difference between the sales line pressure and well shut-in pressure. If the well shut-in pressure is more than 1.5 times the sales line pressure, as required for a plunger lift installation in Exhibit 2, then the volume of gas in the well casing at shut-in pressure should be minimally sufficient to push the liquid in the tubing to the surface in slug-flow when back-pressure is reduced to zero psig. Partners can estimate the minimum time to vent the well by using this volume and the Weymouth gas-flow formula (worked out for common pipe diameters, lengths and pressure drops in Tables 3, 4 and 5 in *Pipeline Rules of Thumb Handbook*, Fourth Edition, pages 283 and 284). If the Partner's practice and experience is to vent the wells a longer time than calculated by these methods, the conservative Annual Vent Volume can be increased by a simple ratio of the actual vent times and the minimum vent time calculated using the Weymouth equation.

Installing Plunger Lift Systems In Gas Wells

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EPA provides the suggested methane emissions estimating methods contained in this document as a tool to develop basic methane emissions estimates only. As regulatory reporting demands a higher-level of accuracy, the methane emission estimating methods and terminology contained in this document may not conform to the Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart W methods or those in other EPA regulations.