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Oil and Natural Gas Sector: Standards for Crude Oil and Natural Gas Facilities

Background Technical Support Document for the
Proposed New Source Performance Standards
40 CFR Part 60, subpart OOOOa

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Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Facilities

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DISCLAIMER

FOREWORD

This background technical support document (TSD) provides information relevant to the proposal of amendments to the New Source Performance Standards (NSPS) at 40 CFR 60, subpart OOOO for limiting greenhouse gases (GHG), specifically methane (CH_4), and volatile organic compounds (VOC) emissions from the Oil and Natural Gas Source Category. The proposed amendments, which are being proposed as 40 CFR 60, subpart OOOOa, were developed according to section 111(b)(1)(B) of the Clean Air Act (CAA), which requires the EPA to review and revise, as appropriate, NSPS standards. The NSPS review allows the EPA to identify processes in the oil and natural source category that are not regulated under the current NSPS but may be appropriate to regulate under NSPS based on new information. This would include processes that emit the current regulated pollutants, VOC and sulfur dioxide (SO_2), as well as any additional pollutants that are identified. This document is the result of that review process. Chapter 1 provides an introduction on NSPS regulatory authority. Chapter 2 presents an overview of the oil and natural gas sector and source category. Chapter 3 discusses the entire NSPS review process undertaken for this review. Chapters 4-8 provide information on previously unregulated emissions sources and revisions to standards for sources already regulated by the NSPS. Each chapter describes the emission source, the estimated emissions (on average) from these sources, potential control options identified to reduce these emissions and the cost of each control option identified. In addition, secondary impacts are estimated and the rationale for the proposed NSPS for each emission source is provided. Finally, Chapter 9 summarizes other potential benefits such as natural gas savings and reductions of hazardous air pollutants (HAP) and global warming potential from CH_4.

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ACRONYMS AND ABBREVIATIONS

Acronyms/Abbreviations	**Description**
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_2e	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_2S	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

Acronyms/Abbreviations	Description
$MMtCO_2e$	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 NEW SOURCE PERFORMANCE BACKGROUND

Standards of performance for new stationary sources are established under section 111 of the CAA (42 U.S.C. 7411), as amended in 1977. Section 111 directs the Administrator to establish standards of performance for any category of new stationary sources of air pollution which "…causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare." This TSD supports the proposed standards, which would control CH_4, VOC and SO_2 emissions from the oil and natural gas source category.

1.1 Statutory Authority

Section 111 of the CAA requires the EPA Administrator to list categories of stationary sources, if such sources cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The EPA must then issue performance standards for such source categories. A performance standard reflects the degree of emission limitation achievable through the application of the "best system of emission reduction" (BSER) which the EPA determines has been adequately demonstrated. The EPA may consider certain costs and nonair quality health and environmental impacts and energy requirements when establishing performance standards. Whereas CAA section 112 standards are issued for existing and new stationary sources, standards of performance are issued for new and modified stationary sources. These standards are referred to as NSPS. The EPA has the authority to define the source categories, determine the pollutants for which standards should be developed, identify the facilities within each source category to be covered and set the emission level of the standards.

CAA section 111(b)(1)(B) requires the EPA to "at least every 8 years review and, if appropriate, revise" performance standards unless the "Administrator determines that such review is not appropriate in light of readily available information on the efficacy" of the standard. When conducting a review of an existing performance standard, the EPA has discretion to revise that standard to add emission limits for pollutants or emission sources not currently regulated for that source category.

In setting or revising a performance standard, CAA section 111(a)(1) provides that performance standards are to "reflect the degree of emission limitation achievable through the application of the BSER which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." This level of control is referred to as the BSER. In determining the BSER, a technology review is conducted that identifies what emission reduction systems exist and how much the identified systems reduce air pollution in practice. For each control system identified, the costs and secondary air benefits (or disbenefits) resulting from energy requirements and nonair quality impacts such as solid waste generation are also evaluated. This analysis determines the BSER. The resultant standard is usually a numerical emissions limit, expressed as a performance level (i.e., a rate-based standard or percent control), that reflects the BSER. Although such standards are based on the BSER, the EPA may not prescribe a particular technology that must be used to comply with a performance standard, except in instances where the Administrator determines it is not feasible to prescribe or enforce a standard of performance. Typically, sources remain free to elect whatever control measures that they choose to meet the emission limits. Upon promulgation, a NSPS becomes a national standard to which all new, modified or reconstructed sources must comply.

1.2 Regulatory History of Oil and Natural Gas Source Category

In 1979, the EPA listed crude oil and natural gas production on its priority list of source categories for promulgation of NSPS (44 FR 49222, August 21, 1979). On June 24, 1985 (50 FR 26122), the EPA promulgated NSPS for the source category that addressed VOC emissions from leaking components at onshore natural gas processing plants (40 CFR part 60, subpart KKK). On October 1, 1985 (50 FR 40158), a second NSPS was promulgated for the source category that regulates SO_2 emissions from natural gas processing plants (40 CFR part 60, subpart LLL).

As a result of the review of these standards under CAA section 111(b)(1)(B), in 2012 the EPA published the final rule, "Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution" (40 CFR part 60, subpart OOOO). The rule expanded the existing NSPS to cover several oil and natural gas-related operations not previously covered, including gas well completions, centrifugal and reciprocating compressors, natural gas-operated pneumatic controllers and storage vessels. In 2013 (78 FR 58416) and 2014 (79 FR 79018) the EPA amended the standards set in 2012 in order to improve implementation of the standards.

1.3 NSPS Review Process Overview

In August 2012 (77 FR 49490) and subsequent updates (78 FR 58416, 79 FR 41752, 79 FR 79018, 80 FR 15180 and 80 FR 15180) the EPA published the results of the NSPS review pursuant to CAA section 111(b)(1)(B). Today's proposal does not address any of the covered affected facilities or pollutants that are already regulated in the existing NSPS, with the exception of adding methane as a regulated pollutant for all affected facilities currently regulated for VOC emissions. Standards are being proposed for currently unregulated VOC and CH_4 emission sources, namely hydraulically fractured oil well completions, fugitive emissions from well sites and compressor stations, pneumatic pumps, and pneumatic controllers and compressors in the transmission and storage segment. All of these amendments will be proposed under a new subpart, 40 CFR 60, subpart OOOOa. This proposal is a result of decisions based on the second and third steps of the review which involves evaluating whether there are additional pollutants emitted by facilities in the oil and natural gas source category that contribute significantly to air pollution and may reasonably be anticipated to endanger public health or welfare; and identifying and evaluating additional processes in the oil and natural gas source category that are not covered under the existing NSPS but may be appropriate to develop NSPS based on new information. The entire review process is described in Chapter 3.

2.0 OIL AND NATURAL GAS SECTOR AND SOURCE CATEGORY OVERVIEW

The oil and natural gas sector includes operations involved in the extraction and production of crude oil and natural gas, as well as the processing, transmission and distribution of natural gas. Specifically for oil, the sector includes all operations from the well to the point of custody transfer at a petroleum refinery. For natural gas, the sector includes all operations from the well to the customer. The oil and natural gas operations can generally be separated into four segments: (1) oil and natural gas production, (2) natural gas processing, (3) natural gas transmission and storage and (4) natural gas distribution. Each of these segments is briefly discussed below.

Oil and natural gas production includes both onshore and offshore operations. 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.

Offshore oil and natural gas production occurs on platform structures that house equipment to extract oil and gas from the ocean or lake floor and that process and/or transfer the oil and gas to storage, transport vessels or onshore. Offshore production can also include secondary platform structures connected to the platform structure, storage tanks associated with the platform structure and floating production and offloading equipment.

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. 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 CH_4. However, whether natural gas is associated gas from oil wells or non-associated gas from gas or condensate wells, it commonly exists in mixtures with other hydrocarbons. These hydrocarbons are often referred to as natural gas liquids (NGL). They are sold separately and have a variety of different uses. The raw natural gas often contains water vapor, hydrogen sulfide (H_2S), carbon dioxide (CO_2), helium, nitrogen and other compounds.

Natural gas processing consists of separating certain hydrocarbons and fluids from the natural gas to produced "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 CO_2 removal, fractionation of natural gas liquid and other processes, such as the capture of CO_2 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, 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.

The distribution segment is the final step in delivering natural gas to customers. The natural gas enters the distribution segment from delivery points located on interstate and intrastate transmission pipelines to business and household customers. The delivery point where the natural gas leaves the transmission segment and enters the distribution segment is often called the "citygate." Typically, utilities take ownership of the gas at the citygate. Natural gas distribution systems consist of thousands of miles of piping, including mains and service pipelines to the customers. Distribution systems sometimes have compressor stations, although they are considerably smaller than transmission compressor stations.

Distribution systems include metering stations, which allow distribution companies to monitor the natural gas in the system. Essentially, these metering stations measure the flow of gas and allow distribution companies to track natural gas as it flows through the system.

Emissions can occur from a variety of processes and points throughout the oil and natural gas sector. Primarily, these emissions are organic compounds such as CH_4, ethane, VOC and organic HAP. The most common organic HAP are n-hexane and BTEX compounds (benzene, toluene, ethylbenzene and xylenes). Hydrogen sulfide and SO_2 are emitted from production and processing operations that handle and treat sour gas.[1]

In addition, there are significant emissions associated with the reciprocating internal combustion engines and combustion turbines that power compressors throughout the oil and natural gas sector. However, emissions from internal combustion engines and combustion turbines are covered by regulations specific to engines and turbines and, thus, are not addressed in this action.

In 1979, under Section 111(b)(1)(A) of the CAA, which Congress enacted as part of the 1970 Clean Air Act Amendments, the EPA published a list of source categories for which the EPA would promulgate standards of performance under section 111(b) of the CAA. One of those source categories was "crude oil and natural gas production." The EPA interprets the "crude oil and natural gas production" source category listing as generally covering the oil and natural gas industry. Specifically, with respect to the oil and natural gas industry, the source category is described as the production, processing, and transmission and storage segments of the oil and natural gas sector. The analysis supporting the NSPS as presented 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.

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[1] Sour gas is defined as natural gas with a maximum H_2S content of 0.25 gr/100 scf (4 parts per million by volume (ppmv)) along with the presence of CO_2.

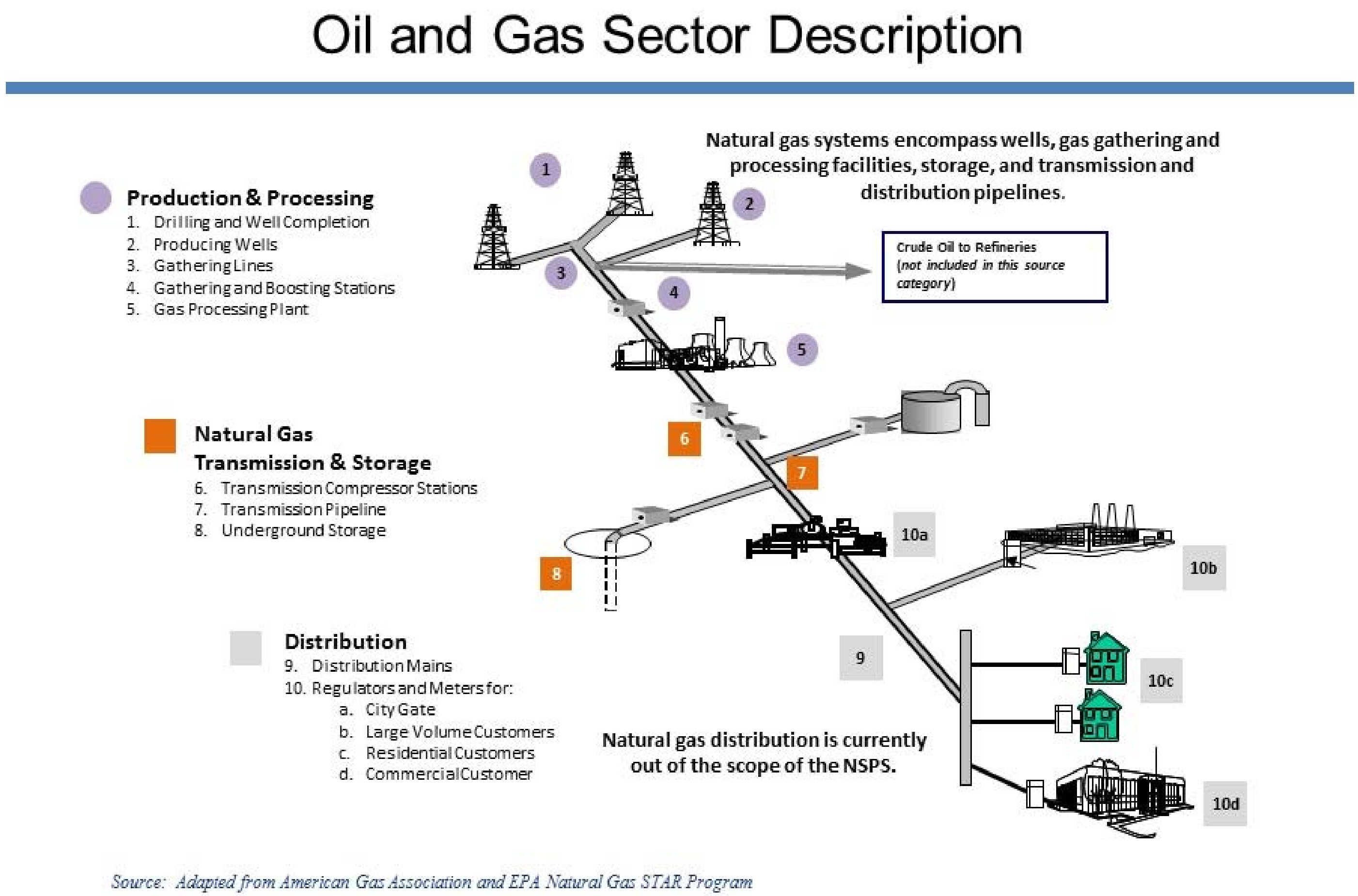

Figure 1. Oil and Natural Gas Sector Operations

3.0 NEW SOURCE PERFORMANCE STANDARD REVIEW

Section 111(b)(1)(B) of the CAA requires the EPA to review and revise, if appropriate, NSPS standards. This review process consists of the following steps:

1. Evaluation of the existing NSPS to determine whether they continue to reflect the BSER for the emission sources that they address;
2. Evaluation of whether there were additional pollutants emitted that warrant regulation and for which there is adequate information to promulgate standards of performance; and
3. Identification of additional processes for which it would be appropriate to develop performance standards, including processes that emit the currently regulated pollutants as well as any additional pollutants identified in step two.

The following sections detail each of these steps.

3.1 Evaluation of the BSER for Existing NSPS

During development of the NSPS amendments promulgated in 2012, BSER options for equipment leaks at natural gas processing plants (subpart KKK) and SO_2 emissions from sweetening units located at natural gas processing plants (subpart LLL) were evaluated, which addressed all existing covered sources and pollutants in the prior NSPS. Therefore, this action includes no control technology evaluations for those sources. In addition, this action does not further evaluate the BSER analyses for currently regulated affected facilities under subpart OOOO.

3.2 Additional Pollutants

The current NSPS (subparts KKK, LLL and OOOO) for the Oil and Natural Gas source category addresses emissions of VOC and SO_2 from certain affected facilities. In addition to these pollutants, sources in this source category also emit a variety of other pollutants, most notably, air toxics. However, there are National Emissions Standards for Hazardous Air Pollutants (NESHAP) that address air toxics from the oil and natural gas source category, specifically 40 CFR subpart HH and 40 CFR subpart HHH.

In addition, processes in the Oil and Natural Gas source category have been found to emit significant amounts of CH_4. The Inventory of U.S. Greenhouse Gas (GHG) Emissions and Sinks: 1990-2013 estimates 2009 CH_4 emissions from Petroleum and Natural Gas Systems (not including petroleum refineries) to be 148 MMtCO_2e (million metric tons of CO_2-equivalents (CO_2e)).[2] As a result, this proposed rule adds GHG emissions, specifically CH_4, as a regulated pollutant for all currently covered affected facilities in the NSPS as well as the additional affected facilities identified in these amendments. The CH_4 emissions, reductions and cost of control evaluations for affected facilities that are currently regulated under the rule were included in the technical support documents for the proposed and final NSPS and the supporting memorandum for the subsequent reconsideration for storage vessels in 2013. For convenience, we have summarized the information in a memorandum titled "Summary of Reductions of Methane Emissions and Methane Global Warming Potential For 40 CFR 60 Subpart OOOO Affected Facilities" available in the docket.

Significant emissions of nitrogen oxides (NO_x) also occur at oil and natural gas sites due to the combustion of natural gas in reciprocating engines and combustion turbines used to drive the compressors that move natural gas through the system, and from combustion of natural gas in heaters and boilers. While these engines, turbines, heaters and boilers are co-located with processes in the oil and natural gas sector, they are not in the Oil and Natural Gas source category and are not being addressed in this action. The NO_x emissions from engines and turbines are covered by the Standards of Performance for Stationary Spark Internal Combustion Engines (40 CFR part 60, subpart JJJJ) and Standards of Performance for Stationary Combustion Turbines (40 CFR part 60, subpart KKKK), respectively.

3.3 Additional Processes

The current NSPS covers SO_2 and VOC emissions from gas processing plants and VOC emissions from gas well completions and recompletions, pneumatic controllers, compressors and storage vessels. The EPA has identified several additional sources of CH_4 and VOC that are included in the proposed standards. Specifically the EPA is proposing to regulate CH_4 emissions from all affected facilities currently regulated under subpart OOOO that are regulated for VOC emissions. The EPA is also proposing to regulate CH_4 and VOC from hydraulically fractured oil well completions and recompletions, compressors in the transmission and storage segment, gas-driven pneumatic controllers in the transmission and storage segment, gas-driven pneumatic pumps, and fugitive emissions from well sites and compressor stations. The remainder of this document presents the BSER evaluation for each of the new processes to be included in the NSPS.

[2] U.S. EPA. Inventory of U.S. GHG Emissions and Sinks: 1990-2013. Available at http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Main-Text.pdf.

3.4 Supporting Documentation

As noted above, this action follows the development of several NSPS related actions including the NSPS proposal in 2011 and final rule in 2012 and subsequent reconsideration of the 2012 storage vessel provisions in 2013. 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".[3]
- The supplemental TSD for the 2012 final NSPS standards, published April, 2012, will be referred to in this document as "2012 NSPS STSD".[4]
- 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".[5]
- Emissions information and counts for various emission sources were summarized 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 published data was from 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”.[6] Note that the GHGRP plans to release additional activity data in the fall of 2015 from its Petroleum and Natural Gas Systems source category. These data cover oil and gas operations reporting to the GHGRP in 2011, 2012, 2013 and 2014. These new activity data will be reviewed prior to finalization of this rule and incorporated into this analysis if appropriate.
- 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.

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[3] 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.

[4] 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.

[5] 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.

[6] EPA (2014) *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012*. U.S. Environmental Protection Agency, Washington D.C. EPA 430-R-15-004 Available online at: http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.

4.0 HYDRAULICALLY FRACTURED OIL WELL COMPLETIONS AND RECOMPLETIONS

The 2012 NSPS promulgated requirements for control of emissions from hydraulically fractured natural gas well completions and recompletions. During development of the 2012 NSPS amendments, hydraulically fractured oil well completion and recompletion VOC emissions were estimated and included in the cost and impact analysis. See the 2011 NSPS TSD. At that time, it was found that the cost of control for oil wells was too high, and therefore, no requirements were finalized for control of VOC emissions from oil well completions or recompletions. The EPA was petitioned for review of the 2012 NSPS for several issues, one of which was that petitioners believed the EPA had underestimated the emissions from hydraulically fractured oil well completions and recompletions, which resulted in an overestimation the cost of control, which was the basis for the decision to not include hydraulically fractured oil wells as affected facilities under subpart OOOO.

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 contain multi-phase processes with various sources of emissions with the highest emissions being 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 emission from oil well completions as were found to be appropriate for gas well completions. As such, a BSER analysis was not necessary when considering control technology for application to oil well completion emission. Therefore, we evaluated costs, emission reductions, and secondary impacts for oil well completion and recompletions based on the revised emissions profile. Finally, this chapter discusses a sensitivity analysis conducted with respect to the natural gas production data used for the emissions analysis in comparison to field test data available for hydraulically fractured oil well completions.

Because oil well completions and recompletions were included in the proposed NSPS amendments in 2011 (76 FR 52738), for the sake of convenience we repeat below the process description and control technology discussions from the 2012 NSPS TSD (Section 4.1) with minimal edits.

4.1 Process Description

4.1.1 Oil Well Completions

All oil wells must be "completed" after initial drilling in preparation for production. Oil well completion activities not only will vary across formations, but can vary between wells in the same formation. Over time, completion and recompletion activities may change due to the evolution of well characteristics and technology advancement.

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 rate, 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 backflow 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 backflow 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 backflow 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 backflow of the fracture fluids, completions involving hydraulic fracturing have higher costs and vent substantially more natural gas than completions not involving hydraulic fracturing.

[7] U.S. EPA. Lessons Learned: Reduced Emissions Completions. Office of Air and Radiation (OAR): Natural Gas Star Program, Washington, DC, 2011.

4.1.2 Oil Well Recompletions

During its lifetime, wells may need supplementary maintenance, referred to as recompletions (these are also referred to as workovers). Recompletions are remedial operations required 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 unless the flowback gas is captured.

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 during well cleanup event, when the well also happens to be producing liquids (mostly water) and sand. 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 are vented as the flowback enters the impoundment or vessels. Minimal amounts of emissions are caused by the fluid (mostly water) held in the impoundment or vessels since very little gas is dissolved in the fluid when it enters the impoundment or vessels.

4.2 Emission Data and Emissions Factors

4.2.1 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] The more recent information and data reviewed for the white paper indicates that there is potential for significant emissions from oil well completions and recompletions. Table 4-1 presents a list of the studies or information sources consulted for development of the NSPS development and the 2014 white paper. The list below includes sources with information on hydraulically fractured gas and oil well completions and workovers.

Table 4-1. Major Studies Reviewed Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factor(s)	Emission Information	Control Information
GHG Mandatory Reporting Rule and Technical Supporting Documents[a]	EPA	2013	Nationwide	X	
Inventory of GHG Emissions and Sinks: 1990-2012[b, c]	EPA	2014	Nationwide	X	
CH_4 Emissions from the U.S. Petroleum Industry (Draft)[d]	Radian	1996	Nationwide	X	
CH_4 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	2009	Regional	X	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
	Environmental Conservation				
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
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. Methodology for Estimating CH_4 and CO_2 Emissions from Petroleum Systems. GHG Inventory: Emission and Sinks 1990-2008. Washington, DC. 2010.
c. U.S. EPA. Methodology for Estimating CH_4 and CO_2 Emissions from Natural Gas Systems. GHG Inventory: Emission and Sinks 1990-2008. Washington, DC. 2010.
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 Western States. 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 Operation. 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 4.
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.
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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.

4.2.2 Representative Completion and Recompletion Emissions

As is the case for gas wells under the existing NSPS, the affected facility is considered to be the wellhead. Therefore, a new well drilled after the proposal date of NSPS (or in the case of oil wells, the proposed amendments to the NSPS) would be subject to emission control requirements. Likewise, wells drilled prior to the proposal date of the NSPS (or the amended NSPS) would not be subject to emission control requirements unless they underwent a modification after the proposal date.

Under section 111(a) of the CAA, the term “modification” means:

“any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.”

The wellhead is defined as the piping, casing, tubing, and connected valves protruding above the earth’s surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. In order to fracture an existing well during recompletion, the well would be re-perforated, causing physical change to the wellbore and casing and therefore a physical change to the wellhead, the affected facility. Additionally, much of the emissions data on which this analysis is based demonstrates that hydraulic fracturing of any well results in an increase in emissions. Thus, recompletions using hydraulic fracturing result in an increase in emissions from the existing well producing operations. Based on this understanding of the work performed in order to recomplete the well, it was determined that a recompletion would be considered a modification under CAA section 111(a) and thus, would constitute a new wellhead affected facility subject to NSPS.

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 during the initial phase of well preparation or during recompletion maintenance and/or re-fracturing of an existing well.

This analysis assumes wells completed/recompleted with hydraulic fracturing are found in tight sand, shale, or coal bed CH_4 formations. The basic approach for this analysis was to use natural gas production data to approximate natural gas emissions from representative oil completions and recompletions and then estimate CH_4 and VOC emissions using a the representative gas composition values developed in the 2011 Gas Composition Memorandum for the 2012 NSPS.[9]

Based on comments received during the development of the NSPS, we 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 with 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, we evaluated available information to determine a minimum threshold of gas produced. We believe that having no threshold may create a significant burden for operators to control emissions for these wells with just a trace of gas.

We determined the most reasonable parameter to base the threshold was the gas to oil ratio (GOR). The threshold must be low enough that the oil produced is considered non-volatile. 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 will not likely have enough gas associated that it can be separated. Therefore, for our analysis, we set a of GOR of less than 300 scf/barrel as the threshold under which an oil well completion would not be reasonably capable of capturing and controlling emissions. For our analysis, we removed these oil wells from the evaluation to determine emissions from hydraulically fractured oil wells.

The following methodology was used to estimate the potential CH_4 and VOC from hydraulically fractured oil well completions.

1. The EPA obtained well production data from the DrillingInfo database dated February, 2014.[12] 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,

[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] 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.

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 all wells not characterized in the DrillingInfo database as defined as “oil,” “gas” or “oil and gas” from the dataset.
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 Texas[13] and New Mexico[14].
5. Based on the calculated GOR for the wells identified above, we eliminated from the 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

[13] 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.

[14] Available at http://164.64.110.239/nmac/parts/title19/19.015.0002.htm.

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 well (i.e., hydraulically fractured, and completed in 2012).
8. To determine the potential CH_4 and VOC emissions for a representative oil well completion or recompletion, we converted the average natural gas potential emissions per day to short tons of potential CH_4 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.[15] Specifically, we assume natural gas is 46.71% CH_4 by volume, the density of CH_4 is 0.0208 tons per Mcf, and that there is 0.8374 lbs of VOC per pound of CH_4.

We then calculated the potential VOC and CH_4 emissions during a hydraulically fractured oil well flowback by multiplying potential CH_4 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 (e.g. Allen et al.) 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 the lowest end of the gas well flowback duration towards the low end of that range, 3 days.

Table 4-2 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 emissions estimates (8 to around 200 tons CH_4 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. The estimate presented in the table below was developed using a method relying on flowback and gas production data, which allowed the EPA to develop a factor that reflects GOR thresholds that exclude gas wells and oil wells that produce very little gas. The estimates in the table below represent emissions from

[15] See footnote 5.

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 to reduce the potential value.

Table 4-2. Uncontrolled Emissions Estimates from Representative Oil Well Completion or Recompletion

	Average Daily Production Natural Gas (Mcf/event)	Potential Emissions CH_4 [a] (tons/event)	Potential Emissions VOC [b] (tons/event)
3-Day Completion or Recompletion Event	999	9.72	8.14

a. It is assumed CH_4 comprises 46.732 percent by volume of natural gas. The factor used to convert CH_4 from volume to weight is 0.0208 tons CH_4 per thousand cubic feet (Mcf) of CH_4.[16]
b. Assumes 0.8374 lb. VOC/lb. CH_4.

4.3 Nationwide Emissions from New Sources

4.3.1 Determination of Number of Completions and Recompletions

The first step in this analysis is to estimate nationwide baseline emissions. In order to develop the baseline emissions, we estimate the average number of new wells that would be affected using the number of completions and recompletions performed in a typical year as derived from the DrillingInfo database extract as described above. The EPA used 2012 as the base year for this analysis. This value was then multiplied by the potential uncontrolled emissions per well completion listed in Table 4-2.

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 reduction benefits 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

[16] U.S EPA. Methodology for Estimating CH_4 and CO_2 Emissions from Petroleum Systems. Greenhouse Gas Inventory: Emission and Sinks 1990-2008. Washington, DC. 2010. Appendix B, Pgs. 87-89.

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. Colorado and Wyoming were the only States identified as requiring controls on completions 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.[17] 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.[18] It was assumed for this analysis 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 regulated to recompletions. We 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 7 percent of completions are controlled in absence of federal regulation. For the base year 2012 we estimated a total number of completions and recompletions to be 20,422. From this number we removed all oil wells below the GOR threshold of 300 scf per barrel, as discussed above resulting in a total number completions and recompletions of 15,594.

Finally, we determined the number of exploratory oil well completions based on the percentage breakdown between exploratory and development wells in the National Energy Modeling System

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[17] Wyoming BACT permitting guidance. Available at http://deq.state.wy.us/aqd/Oil%20and%20Gas/September%202013%20FINAL_Oil%20and%20Gas%20Revision_UGRB.pdf.
[18] 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.

(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, we could not identify a national level data source on this practice from which we 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, we assumed zero for our analysis of baseline emissions.

Table 4-3 summarizes the estimated number of hydraulically fractured oil well completions derived from our analysis detailed above.

Table 4-3. Estimated Number of Hydraulically Fractured Oil Well Completions and Recompletions for a Representative Year (2012)

Well Completion Category	Estimated Number of Total Completions and Recompletions	Estimated Number of Controlled Completions and Recompletions[a]	Estimated Number of Uncontrolled Completions and Recompletions
1. Developmental Oil Well	15,002	1,190	13,812
2. Exploratory/Delineation Oil Well	592	47	545

a. Reflects completions and recompletions covered by state regulations in Colorado and Wyoming.

4.3.2 Projected Number of Completions and Recompletions for 2020 and 2025

For our analysis, we project the activity factors for future dates. In order to determine nationwide impacts of the number of new oil well completions and recompletions, we used the base year of 2012 activity data as described above and projected activity numbers for the years 2020 and 2025 based on predictions from the NEMS Oil and Gas Supply Model. We calculated the compound annual growth rate (CAGR) between 2012 and 2015 for development and exploratory oil wells based on the AEO 2014 Reference Case. The CAGR for development wells was found to be -.01 percent and the CAGR for exploratory wells was found to be 6.03 percent. These factors were used to calculate the number of exploratory and development oil well completion for the years 2020 and 2015.

The number of projected estimated well completions and recompletions for each well source subcategory used in our analysis is summarized in Table 4-4.

Table 4-4. Estimated Number of Oil Well Completions and Recompletions for 2020 and 2025

Well Source Subcategory	Estimated Number of Total Completions and Recompletions	Estimated Number of Controlled Completions and Recompletions[a]	Estimated Number of Uncontrolled Completions and Recompletions
Base Year 2012			
1. Developmental Oil Well	15,002	1,190	13,812
2. Exploratory Oil Well	592	47	545
Projected Year 2020			
1. Developmental Oil Well	15,707	1,901	13,806
2. Exploratory Oil Well	946	75	870
Projected Year 2025			
1. Developmental Oil Well	16,200	2,396	13,803
2. Exploratory Oil Well	1,267	101	1,166

a. Reflects completions and recompletions covered by state regulations in Colorado and Wyoming.

4.3.3 Emission Estimates

Using the estimated emissions per source as shown in Table 4-2, 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 4-5. All values have been rounded to the nearest ton for estimation purposes.

Table 4-5. 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)	
	CH_4	VOC		CH_4[b]	VOC[b]
Base Year 2012					
All Oil Wells	9.72	8.14	14,357	139,542	116,853
1. Developmental Oil Wells	9.72	8.14	13,812	134,245	112,417
2. Exploratory/Delineation Oil Wells	9.72	8.14	545	5,297	4,436
Projected Year 2020					
All Oil Wells	9.72	8.14	14,677	142,649	119,454
1. Developmental Oil Wells	9.72	8.14	13,806	134,188	112,369
2. Exploratory/Delineation Oil Wells	9.72	8.14	870	8,460	7,085
Projected Year 2025					
All Oil Wells	9.72	8.14	14,970	145,496	121,839
1. Developmental Oil Wells	9.72	8.14	13,803	134,160	112,345
2. Exploratory/Delineation Oil Wells	9.72	8.14	1,166	11,337	9,493

a. The number of controlled and uncontrolled wells estimated based on State regulations.
b. Based on the assumption that VOC content is 0.8374 lbs VOC per pound CH_4. 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.

4.4 Control Techniques

4.4.1 Potential Control Techniques

The EPA considered the same two techniques that have been proven to reduce emissions from well completions and recompletions that were evaluated for development of the NSPS and codified 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. As both of these techniques were determined to be BSER for gas wells for the NSPS (the use of REC was determined to be BSER when the recovered gas can be directed to a sales line, and completion combustion was determined to BSER when it is not feasible to direct the gas to a sales line), and 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. We 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 following sections describe the cost impact of these technologies with respect to oil well completions based on our current analysis of emissions.

4.4.2 Reduce Emission Completions and Recompletions

4.4.2.1 Description

Reduced emission completions, also referred to as "green" completions, use specially designed equipment at the well site to capture and treat gas so it can be directed to the sales line. This process prevents some natural gas from venting and results in additional economic benefit from the sale 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.[19]

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).[20] In instances where formations are stacked vertically and horizontal drilling could take place, it may be possible that

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[19] U.S. EPA Fact Sheet No. 703: Green Completions. OAR: Natural Gas Star Program. Washington, DC. September 2004.
[20] Memorandum to Bruce Moore, U.S. EPA from Denise Grubert, EC/R. API Meeting Minutes. July 2010.

existing surface REC equipment may be located near an exploratory well, which would allow for a REC.

- Pressure of produced gas. During each stage of the completion/recompletion process, the pressure of flowback fluids may not be sufficient to overcome the sales line backpressure. This pressure is dependent on the specific sales line pressure and can be highly variable. 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 control option is compressor applications. One application is gas lift which is accomplished by withdrawing gas from the sales line, boosting its pressure, and routing it down the well casing to push the fracture fluids up the tubing. The increased pressure facilitates flow into the separator and then the sales line where the lift gas becomes part of the normal flowback that can be recovered during a REC. Another potential 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 CO_2, 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.

4.4.2.2 Emission Reduction Potential

RECs are an effective emissions reduction method for oil well completions and recompletions performed with hydraulic fracturing based on the estimated flowback emissions described in Section 4.2. The emissions 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.[21] Any amount of gas that cannot be recovered can be directed to a completion combustion device in order to achieve a minimum 95 percent reduction in emissions.

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[21] Memorandum to Bruce Moore, U.S. EPA from ICF Consulting. Percent of Emissions Recovered by Reduced Emission Completions. May 2011.

4.4.2.3 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 TSD[22], the annual cost of performing a REC was estimated to be $12,735 for a representative well completion lasting 3 days[23]. For our analysis, the cost is adjusted to 2012 dollars using the Gross Domestic Product: Implicit Price Deflator.[24] 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.[25] 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. The first method, the single-pollutant method, allocates all of the costs to each pollutant separately. The

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[22] See footnote 3.
[23] This cost was based on state of the industry in 2006 and adjusted to 2008 US Dollars. For the 2012 NSPS we determined a cost per day value, however, the 2012 NSPS applied this per day cost to a 7-day event duration. Here we use the same cost per day and a 3-day event duration.
[24] Available at http://research.stlouisfed.org/fred2/series/GDPDEF/.
[25] When including the additional natural gas recovery in the cost analysis, we 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.

second method, the multi-pollutant method, allocates costs among the pollutants that a given technology reduced (i.e., methane and VOC). 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 each pollutant and $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 4-6 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 each pollutant 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 4-6 provides a summary of REC cost per ton of emission reduction.

In order to accomplish 95 percent control, the combination of a combustion device and the REC can be used. For the combined REC and combustion device 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 each pollutant individually. 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 device, 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 each pollutant individually 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 4-6 provides a summary of REC cost per ton of emission reduction.

4.4.2.4 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.

4.4.3 Completion Combustion Devices

4.4.3.1 Description

Completion combustion is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, found in waste streams.[26] Completion combustion devices are used to control VOC in many industrial settings, since the completion combustion device can normally handle fluctuations in concentration, flow rate, heating value, and inert species content.[27] Completion 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. However, the flow directed to a completion combustion device may or may not be combustible depending on the inert gas composition of flowback gas, which would require a continuous ignition source. Sometimes referred to as pit flares, these types of combustion devices do not employ an actual control device, and are not capable of being tested or monitored for efficiency. They do provide a means of minimizing vented gas and is preferable to venting. For the purpose of this analysis, the term completion combustion device represents all types of combustion devices including pit flares.

4.4.3.2 Emission Reduction Potential

As mentioned previously, it is difficult to accurately measure the destruction efficiency of a completion combustion device. 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

[26] U.S. EPA. AP-42, Fifth Edition, Volume I, Chapter 13.5 Industrial Flares. OAQPS. 1991.
[27] U.S. EPA. Air Pollution Control Technology Fact Sheet: FLARES. Clean Air Technology Center.

impacts in some situations (e.g., dry, windy conditions, proximity to residences, etc.). As a result, we are aware that owners and operators may not be able to combust unrecoverable gas safely in every case.

The General Provisions to 40 CFR part 60 specify design and operational requirements for flares to assure that a high level of destruction efficiency is achieved at all times (see 40 CFR 60.18(b)). Because completion combustion devices are not flares, the requirements of 40 CFR 60.18(b) do not apply to them. Concerns have been raised on applicability of 40 CFR 60.18 within the oil and gas industry including for the production segment.[28,29,30] The design and nature of completion combustion devices must handle multiphase flow and stream compositions that vary during the flowback period. Thus, the applicability criterion that specifies conditions for flares used in highly industrial settings may not be appropriate for flares typically used to control emissions from well completions and recompletions.

4.4.3.3 Cost Potential

An analysis estimating the cost for wells including completion combustion devices was conducted for the 2012 NSPS, resulting in an estimated average completion combustion device cost of approximately $3,523 (2008 dollars).[31] For our analysis, this cost was adjusted to 2012 dollars using the Gross Domestic Product: Implicit Price Deflator [32] 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 estimations. 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 allocated all of the costs to each pollutant individually. The second method allocated costs among the pollutants that a given technology reduced (i.e., CH_4 and VOC). This allocation was based on estimates of the percentage reduction expected for each pollutant. Completion

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[28] See footnote 20.
[29] Memorandum to Bruce Moore from Denise Grubert. API Meeting Minutes. EC/R, Incorporated. October 2010.
[30] Memorandum to Bruce Moore from Denise Grubert. API Meeting Minutes Attachment 1: Review of Federal Air Regulations for the Oil and Natural Gas Sector 40 CFR Part 60, Subparts KKK and LLL; 40 CFR Part 63 Subparts HH and HHH. EC/R, Incorporated. February 2011.
[31] 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.
[32] See footnote 24.

combustion devices have a cost of control of $403 per ton of methane and $481 per ton of VOC for oil well completions and recompletions when 100 percent of the cost is attributed to methane and 100 percent to VOC. 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 4-6.

Since this analysis assumed completion combustion devices achieve 95 percent efficiency over the duration of flowback, it is likely the secondary emission estimations are lower than in actuality (i.e. AP-42 assumes 98 percent efficiency). In addition due, to the potential for the incomplete combustion of natural gas across the completion combustion device plume, the likelihood of additional NO_x formulating is also likely. The degree of combustion is variable and depends on the rate and extent of fuel mixing with air and on the flame temperature. Moreover, the actual NO_x (and carbon monoxide (CO)) emissions may be greatly affected when the raw gas contains hydrocarbon liquids and water. For these reasons, the nationwide impacts of combustion devices discussed in Section 4.5 should be considered minimum estimates of secondary emissions from combustion devices.

4.4.3.4 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), CO_2, and smoke/particulates. The degree of combustion depends on the rate and extent of fuel mixing with air and the temperature maintained by the flame. Most hydrocarbons with carbon-to-hydrogen ratios greater than 0.33 are likely to smoke.[33] The high CH_4 content of the gas stream routed to the completion combustion device, it 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.[34]

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

[33] See footnote 25.
[34] Ibid.

80 percent propylene and 20 percent propane.[35] These emissions factors, however, are the best indication for secondary pollutants from flare operations currently available. These secondary emission factors are provided are provided in Table 4-7. Table 4-9 and 4-10 summarize estimated secondary emissions from oil wells based control scenarios using completion combustion devices.

[35] Ibid.

Table 4-6. 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)	
	CH_4	VOC				CH_4	VOC	CH_4	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 4-7. Emission Factors from Flare Operations from AP-42 Guidelines Table 13.4-1[a]

Pollutant	Emission Factor ($lb/10^6$ Btu)
THC[b]	0.14
CO	0.37
NO_x	0.068
PM[c]	2.56e-3
CO_2[d]	60

a. Based on combustion efficiency of 98 percent.
b. Measured as CH_4 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 is measured in kg CO_2/MMBtu and is derived from the CO_2 emission factor obtained from 40 CFR Part 98, subpart Y, Equation Y-2.

4.5 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, and would therefore be the preferred option. As discussed above, REC is only an option for reducing emissions from gas well completions/workovers with hydraulic fracturing. Taking this into consideration, the following regulatory alternatives were evaluated:

- <u>Regulatory Option 1.</u> Require completion combustion devices for all hydraulically fractured oil well completions and recompletions;
- <u>Regulatory Option 2.</u> Require REC for all hydraulically fractured oil well completions and recompletions;
- <u>Regulatory Option 3.</u> Require REC and combustion operational standards for hydraulically fractured oil well completions and recompletions, with the exception of exploratory, and delineation wells; and
- <u>Regulatory Option 4.</u> Require combustion operational standards for completions of exploratory and delineation wells.

The following sections discuss these regulatory options.

4.5.1 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, etc.). Therefore, Regulatory Option 1 was rejected.

The second regulatory option would require RECs for all completions and recompletions of hydraulically fractured oil wells. As stated previously, RECs are not feasible for all well completions, such as exploratory wells, due to their distance from sales lines, etc. Further, RECs are also not technically feasible for each well at all times during completion and recompletion activities due to the variability of the pressure of produced gas and/or inert gas concentrations. Therefore, Regulatory Option 2 was rejected.

The third regulatory option was to require an operational standard consisting 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 and/or inert gas concentrations. In order to allow for wellhead 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), Regulatory Option 3 also allows for the use of a completion combustion device in combination with RECs. Under section 111(h)(2) of the CAA, the EPA can set an operational standard which represents the best system of continuous emission reduction, provided the following criteria are met:

> "(A) a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State, or local law, or
> (B) the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations."

As discussed in section 4.4.3, emissions from a completion combustion device cannot be reliably measured or monitored to determine efficiency making an operational standard appropriate. Therefore, an operational standard under this regulatory option consists of a combination of REC and a completion combustion device to minimize the venting of natural gas and condensate vapors to the atmosphere, but allows venting in lieu of combustion for situations in which combustion would present safety hazards, other concerns, or for periods when the flowback gas is noncombustible due to high concentrations of inert gases. Sources would also be required, under this regulatory option, to maintain documentation of the overall duration of the completion event, duration of recovery using REC, duration of combustion, duration of venting, and specific reasons for venting in lieu of combustion. It was also evaluated whether Regulatory Option 3 should apply to all well completions, including exploratory and delineation wells.

As discussed previously, one of the technical limitations of RECs is that they are not feasible for use at some wells due to their proximity to gas pipelines. Section 111(b)(2) of the CAA allows EPA to "…distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing…." performance standards. Due to their distance from sales lines, and the relatively unknown characteristics of the formation, completion activities occurring at exploratory or delineation wells were considered to be a different "type" of activity than the types of completion activities occurring at all other gas wells. Therefore, two subcategories of completions were identified: Subcategory 1 wells are oil wells completed with hydraulic fracturing that do not fit the definition of exploratory or delineation wells. Subcategory 2 wells that meet the following definitions of exploratory or delineation wells:

- <u>Exploratory wells</u> are wells outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists or
- <u>Delineation wells</u> means a well drilled in order to determine the boundary of a field or producing reservoir.

Based on this subcategorization, Regulatory Option 3 would apply to the Subcategory 1 wells and a fourth regulatory option was developed for Subcategory 2 wells.

Regulatory Option 4 requires an operational standard for combustion for the Subcategory 2 wells. As discussed above, a REC is not an option for exploratory and delineation wells based on their distance from sales lines. As with the Regulatory Option 3, a numerical limitation is not feasible. Therefore, this regulatory option requires an operational standard where emissions are minimized using a completion combustion device during completion activities at Subcategory 2 wells, with an allowance for venting in situations where combustion presents safety hazards or other concerns or for periods when the flowback gas is noncombustible due to high concentrations of inert gases. Consistent with Regulatory Option 3, records would be required to document the overall duration of the completion event, the duration of combustion, the duration of venting, and specific reasons for venting in lieu of combustion.

In summary, Regulatory Options 1 and 2 were determined to be unreasonable due to undesirable loss of natural gas or technical feasibility and thereby rejected. Regulatory Options 3 and 4 were determined to be applicable to oil wells and were evaluated further.

4.5.2 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 Regulatory Options 3 and 4 which were selected as viable options for setting standards for completions and recompletions.

4.5.2.1 Primary Environmental Impacts of Regulatory Options

Regulatory Options 3 and 4 were selected as options for setting standards for completions and regulatory options as follows:

- <u>Regulatory Option 3.</u> Operational standard for completions and recompletions with hydraulic fracturing for Subcategory 1 wells (i.e., wells which do not meet the definition of exploratory or delineation wells), which requires a combination of REC with combustion, but allows for venting during specified situations.
- <u>Regulatory Option 4.</u> An operational standard for completions with hydraulic fracturing for exploratory and delineation wells (i.e., Subcategory 2 wells) which requires completion combustion devices with an allowance for venting during specified situations.

The number of completions and recompletions that would be subject to the regulatory options listed above was presented in Table 4-3. From Table 4-4, it was estimated that there would be an estimated 13,806 hydraulically fractured developmental oil well completions and recompletions subject to Regulatory Option 3 in 2020 and an estimated 13,803 oil well completions and recompletions in 2025. Regulatory Option 4 would apply to 870 uncontrolled exploratory oil well completions and recompletions with hydraulic fracturing in 2020 and 1,100 oil well completions and recompletions in 2025. Because not all wells will have available infrastructure or will not otherwise be technically eligible to conduct RECs, we estimate that 50 percent of the uncontrolled subcategory 1 oil wells will be affected by the REC requirement and the other 50 percent will control emissions by combustion.

Table 4-8 summarizes the nationwide emission reduction estimates for each regulatory option 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. Nationwide emission reductions were estimated by applying this 95 percent VOC reduction to the uncontrolled baseline emissions presented in Table 4-4.

4.5.2.2 Cost Impacts

The operational standards for Regulatory Options 3 and 4 include both REC and a completion combustion device, therefore the total incremental cost of the operational standard for Subcategory 1 completions and for recompletions is estimated at around $17,183, which includes the costs in Table 4-6 for the REC equipment and transportation in addition to the cost for the completion combustion device. Applying the cost for the combined REC with completion combustion device to the estimated 6,903 and combustion device only to the estimated 6,903 Subcategory 1 completions and recompletions in projected year 2020, the total nationwide cost was estimated to be approximately $119 million, which includes an estimated annual savings of approximately $25 million when natural gas savings are considered. Likewise, for projected year 2025, the cost for RECs with combustion device applied to 6,902 Subcategory 1 completions and recompletions and the cost for combustion only applied to 6,902 Subcategory 1 completions and recompletions, the total nationwide cost was estimated to be approximately $119 million, including annual savings estimated at around $25 million when natural gas savings are considered. For Regulatory Option 4, the costs for completion combustion devices presented in Table 4-6 would apply to Subcategory 2 completions. The cost per completion event was estimated to be $3,723. Applied to the 870 estimated Subcategory 2 completions and recompletions in projected year 2020, the nationwide costs were estimated to be $3.2 million.

Table 4-8. Nationwide Emission and Cost Analysis of Regulatory Option

Well Completion Category	Number of Sources Subject to NSPS[a]	Annual Cost Per Completion Event[b] ($)	Nationwide Emission Reductions[c] (tpy)		Total Nationwide Costs ($/year)	
			Methane	VOC	without savings	with savings[d]
Base Year 2012						
Regulatory Option 3						
1. Development Oil Wells[e]	6,906	$17,183	63,766	53,398	$118,664,480	$93,822,939
1. Development Oil Wells[f]	6,906	$3,723	63,766	53,398	$25,714,478	$25,714,478
Regulatory Option 4						
2. Exploratory/Delineation Oil Wells	545	$3,723	5,032	4,214	$2,029,306	$2,029,306
Combined Option 3 and 4	14,357	NA	132,565	111,010	146,408,265	121,566,723
Projected Year 2020						
Regulatory Option 3						
1. Development Oil Wells[e]	6,903	$17,183	63,739	53,375	$118,614,014	$93,783,037
1. Development Oil Wells[f]	6,903	$3,723	63,739	53,375	$25,703,542	$25,703,542
Regulatory Option 4						
2. Exploratory/Delineation Oil Wells	870	$3,723	8,037	6,730	$3,241,154	$3,241,154
Combined Option 3 and 4	14,677	NA	135,516	113,481	147,558,710	122,727,733
Projected Year 2025						
Regulatory Option 3						
1. Development Oil Wells[e]	6,902	$17,183	63,726	53,364	$118,588,789	$93,763,093
1. Development Oil Wells[f]	6,902	$3,723	63,726	53,364	$25,698,076	$25,698,076
Regulatory Option 4						
2. Exploratory/Delineation Oil Wells	1,166	$3,723	10,770	9,019	$4,343,048	$4,343,048
Combined Option 3 and 4	14,970	N/A	138,221	115,747	148,629,913	123,804,217

a. Number of sources in each well completion category that are uncontrolled at baseline as presented in Table 4-3.
b. Costs per event for Regulatory Options 3 is the cost of a REC combined with the cost of a completions device, and the cost for Option 4 is a completion combustion device only.
c. Nationwide emission reductions calculated by applying the 95 percent emission reduction efficiency to the uncontrolled nationwide baseline emissions in Table 4-4.
d. For developmental using a REC, assumes a cost savings for 899 Mcf gas recovered per completion event, valued at $4.00 Mcf, for a total savings of $3,597 per event.
e. These well completions are estimated to be eligible to conduct a REC (i.e., infrastructure and/or other well technical aspects support a REC).
f. These well completions are estimated to not be eligible to conduct a REC and must combust emissions.

4.5.2.3 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 95 percent (or 949 Mcf) of flowback emissions are combusted by the combustion device. The ns 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 4-7.

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 4-9 summarizes the estimated secondary emissions of the selected regulatory options for projected year 2020 and Table 4-10 summarizes the estimated secondary emissions of the selected regulatory options for projected year 2025.

Table 4-9. 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	26	0.076	526	0.076	66	619
CO	0.010	69	0.201	1,390	0.201	175	1,635
NO_x	0.002	13	0.037	255	0.037	32	300
PM	0.000	0	0.001	9	0.001	1	10
CO_2	3.599	24,846	71.987	496,924	71.987	62,628	584,399

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 6,903 developmental oil well completions and recompletions using this control scenario.

c. Assumes 949 Mcf of natural gas is sent to the combustion unit and 902 Mcf is combusted per completion. This analysis assumes 6,903 development oil well completions and recompletions exploratory wells fall into this category.

d. Assumes 949 Mcf of natural gas is sent to the combustion unit and 902 Mcf is combusted per completion. This analysis assumes 870 exploratory wells fall into this category.

Table 4-10. 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	526	0.076	84	636
CO	0.010	69	0.201	1,390	0.201	221	1,681
NO_x	0.002	13	0.037	255	0.037	41	309
PM	0.000	0	0.001	9	0.001	1	10
CO_2	3.599	24,843	71.987	496,852	71.987	79,185	600,880

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 6,902 developmental oil well completions and recompletions using this control scenario.

c. Assumes 949 Mcf of natural gas is sent to the combustion unit and 902 Mcf is combusted per completion. This analysis assumes 6,902 development oil well completions and recompletions exploratory wells fall into this category.

d. Assumes 949 Mcf of natural gas is sent to the combustion unit and 902 Mcf is combusted per completion. This analysis assumes 1,100 exploratory wells fall into this category.

4.6 Comparison of Flowback Emissions Estimate Methodology to Measured Emissions from UT-Austin – Allen et al. Study[36]

A limited number of measurements have been conducted on hydraulically fractured oil well completions, in Allen et al. Due to the small sample size, these data were not used to estimate nationwide emissions from oil well completions in this analysis. However, data from Allen et al can be used to assess the emissions estimation methodology described in Section 4.2.2 above.

In comments on the white paper on this emissions source, Dr. Allen compared the "measured potential emissions" for oil well completions from Allen et al. to an estimate of potential well completion emissions calculated using data from the first month of gas production for those wells. For three of the four wells included in his assessment, the measured potential emissions from Allen et al. compared very well with emissions calculated using the average daily gas production for the first month of production and the flowback duration of each well, with ratios of measured potential emissions to estimated potential emissions based on duration and gas production ranging from 1.05 to 1.4. A fourth well included in the assessment had measured potential emissions that were 31 times higher than the potential emissions measured based on initial production and flowback. There was some uncertainty with the flowback duration of the completion event at the fourth well, as described in Allen et al. Dr. Allen noted in his comments the method led to reasonable results for three wells, but that the fourth well demonstrates that consistent application of the method may be difficult.

In the EPA's analysis, the methodology to develop an average estimate of potential emissions for hydraulically fractured oil well completions in the U.S. uses data on gas production for each oil well completed in 2012 during the first month of operation from the Drilling Info database. Average daily production in the first month of operation was then multiplied by an estimate of the average number of days of flowback (3 days) to calculate potential well completion emissions for each well in the data set. The values for potential emissions per completion for all of the wells were then averaged. The EPA expects that like other oil and gas emissions sources, oil well completions may have a wide range of emissions. The EPA believes that the emissions rate it calculated in section 4.2.2 represents a reasonable estimate of average, uncontrolled emissions.

[36] UT Austin - Allen et al., Measurements of methane emissions at natural gas production sites in the United States. PNAS USA (110:17778-17773) September 2013.

Table 4-11. Comparison of Flowback Emissions Estimate Methodology to Measured Emissions from the UT Austin - Allen et al. Study

Well ID	GOR (scf/bbl)	First Month Gas Production Rate (Mcf/day)[a]	Duration of Flowback (days)	Gas Production Rate x Duration of Flowback (Mcf)	Estimated Potential CH_4 Emissions[b] (Mcf/completion)	Measured Potential CH_4 Emissions[a] (Mcf)	Ratio of Measured Potential Emissions to Estimated Emissions
GC-1	4,046	3,000	3.13	9,375	4,381	5,000	1.14
GC-2	4,267	2,700	3.17	8,550	3,995	4,250	1.06
GC-6	30,703	6,100	6.83	41,683	19,479	12,200	0.63
GC-7	3,508	1,500	4.50	6,750	3,154	4,320	1.37

a. From Allen, et al. (2013), Supporting Information, Table S1-6.
b. Allen et al. notes that there was ambiguity in the report data as to the duration of this flowback period. This well had an initial flowback to an open top tank that lasted for 28 hours. After 28 hours, the flow was directed to a separator and the gas from the separator was then sent to sales and a flare. In this case 28 hours was defined as the duration of the flowback, as reported by the company, since gas had begun to go to sales. The study team reported emissions from this flowback that included emissions from the flare, which occurred after the initial 28 hours of flowback.

5.0 FUGITIVE EMISSIONS STANDARDS

Fugitive emissions from components in the oil and natural gas source category are a source of CH_4 and VOC emissions. This chapter explains the causes for these fugitive emissions, and provides CH_4 and VOC emission estimates for "model" facilities in the production and transmission and storage segments. In addition, nationwide equipment fugitive emission estimates from new sources are estimated. Programs that are designed to reduce fugitive emissions are explained, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for fugitive emissions from equipment.

5.1 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 pressure or mechanical stresses can also cause components or equipment to emit fugitive emissions. Potential sources of fugitive emissions include agitator seals, connectors, pump diaphragms, flanges, instruments, meters, open-ended lines (OELs), pressure relief devices, 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.

For the purposes of the analysis and regulatory evaluation of fugitive emissions from components and equipment, we determined the need to differentiate between the current definition of "equipment" in the rule[37] and the intended definition for the purposes of addressing fugitive emissions. Therefore, we have defined a new term, "fugitive emissions component" as the focus of the requirements for fugitive emissions. 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

[37] 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.

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.

In April of 2014, the EPA published a white paper[38] which summarized the EPA's current understanding of CH_4 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. The leaks white paper identified 12 studies or publicly available sources that provided fugitive emission estimates from the various segments of the oil and natural gas industry. Many of the fugitive emission measurements were conducted with EPA Method 21 instruments (e.g., organic vapor analyzer (OVA), flame ionization detector, flow measurement devices). In addition to EPA Method 21 analyzers, several studies conducted fugitive emission surveys using optical gas imaging (OGI) in conjunction with portable Method 21 analyzers and gas chromatograph equipment to measure individual VOC and HAP compounds. These studies provided emission estimates in the form of component or equipment emission factors or emission estimates by facility. Fugitive emission estimates for CH_4 and VOC ranged from 1.4 to 32 tons per year (tpy) and 0.4 to 10 tpy, respectively for oil and natural gas production sites. Even though there is a wide variation in the potential CH_4 and VOC emissions, the studies showed that there are economical options for reducing these emissions.

5.2 Fugitive Emissions Data and Emissions Factors

5.2.1 Summary of Major Studies and Emission Factors

The *Oil and Natural Gas Sector Leaks* white paper provided a summary of fugitive emission studies at oil and natural gas production and compressor stations. In the evaluation of the emissions and emission reduction options for equipment leaks, many of these studies in the white paper were consulted. Table 5-1 presents a list of the studies consulted along with an indication of the type of information contained in the study.

5.2.2 Model Plants

Facilities in the oil and natural gas source category can consist of a variety of combinations of process equipment and other components. This is particularly true in the production segment of the

[38] 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.

industry, where "surface sites" can vary from sites where only a wellhead and associated piping is located to sites where a substantial amount of separation, treatment, and compression occurs. In order to conduct analyses to be used in evaluating potential options to reduce emissions from leaking fugitive emissions components, a model plant approach was used. The following sections discuss the creation of these model plants.

Information related to fugitive emissions components counts was obtained from the GRI/EPA natural gas industry study[39] and other sources. The GRI/EPA document provided average fugitive emissions component counts for natural gas production, natural gas processing, natural gas transmission and natural gas storage including; valves, connectors, OELs, and pressure relief valves (PRVs). Although these counts do not include all potential fugitive emissions components, as described in the definition, these were the best available data as to counts for fugitive emissions components. These average counts were used to develop model plants for well sites, and compressor stations (including those at gathering and boosting stations, transmission stations, and storage facilities). These fugitive emissions component counts are consistent with those contained in the EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks, and in the EPA's analysis to estimate CH_4 emissions conducted in support of the GHG Mandatory Reporting Rule (subpart W), which was published in the *Federal Register (FR)* on November 30, 2010 (75 FR 74458). As we have emission factors for only a subset of the components which are noted as possible sources for fugitive emissions, the model plants and subsequent emission estimates presented are believed to be lower than the emissions profile for the entire set of components that would be considered for a representative model plant. These model plants are discussed in the following sections.

Table 5-1. Major Studies Reviewed for Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factor(s)	Emissions Data	Control Options
Protocol for Equipment Leak Emission Estimates[a]	EPA	1995	None	X	X
CH_4 Emissions from the Natural Gas Industry: Equipment Leaks[b]	GRI/EPA	1996	Nationwide	X	X
GHG Reporting Program[c]	EPA	2013	Facility	X	
Inventory of GHG Emissions and Sinks: 1990-2013[d]	EPA	2015	Regional	X	

[39] Gas Research Institute (GRI)/U.S. EPA. *Research and Development, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks.* June 1996 (EPA-600/R-96-080h).

Report Name	Affiliation	Year of Report	Activity Factor(s)	Emissions Data	Control Options
Measurements of CH_4 Emissions at Natural Gas Production Sites in the United States (U.S.)[e]	Multiple Affiliations, Academic and Private	2013	Nationwide	X	X
City of Fort Worth Natural Gas Air Quality Study, Final Report[f]	City of Fort Worth	2011	Fort Worth, TX	X	X
Measurements of Well Pad Emissions in Greeley, Colorado[g]	ARCADIS/Sage Environmental Consulting/EPA	2012	Colorado	X	X
Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair (LDAR) Programs Using Infrared (IR) Cameras[h]	Carbon Limits	2013	Canada and the U.S.	X	X
Mobile Measurement Studies in Colorado, Texas, and Wyoming[i]	EPA	2012 and 2014	Colorado, Texas, and Wyoming	X	X
Economic Analysis of CH_4 Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries[j]	ICF International	2014	Nationwide	X	X
Identification and Evaluation of Opportunities to Reduce CH_4 Losses at Four Gas Processing Plants[k]	Clearstone Engineering, Ltd.	2002	4 gas processing plants	X	X
Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites[l]	Clearstone Engineering, Ltd.	2006	5 gas processing plants, 12 well sites, 7 gathering stations	X	X

a. U.S. EPA, 1995. *Protocol for Equipment Leak Emission Estimates.* OAQPS. Research Triangle Park, NC. November 1995. EPA-453/R-95-017. Available at http://www.epa.gov/ttn/chief/efdocs/equiplks.pdf.

b. GRI/U.S. EPA. *Research and Development, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks.* June 1996 (EPA-600/R-96-080h).

c. U.S. EPA. 2013b. *Petroleum and Natural Gas Systems: 2012 Data Summary*. GHG Reporting Program. October 2013.

d. U.S. EPA.2013a. *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2011.* Climate Change Division, Washington, DC. April 2013. Available at http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-Chapter-3-Energy.pdf.

e. Allen, David, T., et al. 2013. *Measurements of methane emissions at natural gas production sites in the U.S.*. Proceedings of the National Academy of Sciences (PNAS) 500 Fifth Street, NW NAS 340 Washington, DC 20001 USA. October 29, 2013. 6 pgs. Available at http://www.pnas.org/content/early/2013/09/10/1304880110.full.pdf+html.

f. ERG and Sage Environmental Consulting, LP. *City of Fort Worth Natural Gas Air Quality Study, Final Report.* Prepared for the City of Fort Worth, Texas. July 13, 2011. Available at http://fortworthtexas.gov/gaswells/default.aspx?id=87074.

g. Modrak, Mark T., et al. *Understanding Direct Emissions Measurement Approaches for Upstream Oil and Gas Production Operations.* Air and Waste Management Association 105th Annual Conference and Exhibition, June 19-22, 2012 in San Antonio, Texas.
h. Carbon Limits. *Quantifying cost-effectiveness of systematic LDAR Programs using IR cameras.* December 24, 2013. Available at http://www.catf.us/resources/publications/files/CATF-Carbon_Limits_Leaks_Interim_Report.pdf.
i. Thoma, Eben D., et al. 2012. *Assessment of Methane and VOC Emissions from Select Upstream Oil and Gas Production Operations Using Remote Measurements, Interim Report on Recent Studies.* Proceedings of the 105th Annual Conference of the Air and Waste Management Association, June 19-22, 2012 in San Antonio, Texas.
j. ICF International. *Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries*. ICF International (Prepared for the Environmental Defense Fund). March 2014.
k. Clearstone Engineering Ltd. *Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants*. June, 2002.
l. Clearstone Engineering Ltd. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*. March 2006.

5.2.2.1 Oil and Gas Production

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 that have associated components that may be sources of fugitive emissions (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) 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 feeding into the production pad and the amount of processing equipment located at the site.

Equipment (e.g., valves, pumps, PRVs, etc.) count data from the GRI/EPA report were used to calculate the average counts of fugitive emissions components located at a natural gas well site. The types of production equipment located at these well site include: gas wellheads, separators, meters/piping, heaters, and dehydrators. The types of components that are associated 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.

For oil wells, component counts were obtained from an American Petroleum Institute (API) workbook[40]. The types of oil well production equipment include: oil well heads, separators, headers and heater/treaters. Fugitive emissions components counts for these production equipment types were

[40] API Workbook 4638, 1996.

estimated using the average component counts for onshore production equipment in the Eastern U.S and the Western U.S. from the EPA/GRI report.

A model plant was developed using the average number of wells associated with a well site using data from the Drillinginfo HPDI® database[41]. EPA estimated the number of wells on a typical well site using a spatial analysis of producing crude oil and natural gas wells from the DrillingInfo HPDI database[42]. Baseline fugitive emissions from well sites depend upon the quantity of equipment and components, which in turn is based on this estimate of wells per well site. To estimate the average number of wells co-located on the same site as a new well completion or recompletion, the EPA developed a pair of algorithms that identified new and existing wells within a given distance of a new well completion or recompletion. This distance was assumed to represent the distance that, if other wells were within the distance, the wells would likely be co-located with the well under examination on the same site. The algorithms were written in the open source R programming language.[43]

The HPDI well and production data used to estimate the average number of well co-located on a well site drew upon the latitude and longitude of new well completions and recompletions as well as the coordinates of all wells producing oil or natural gas in 2012. The first algorithm estimated the distances between each new completion and recompletion and all producing wells, which also includes wells newly completed and producing in 2012, within the same county as the completed well. If the distance between the completed well and producing well was less than the assumed size of a typical well site, the two wells were assumed to be co-located. This algorithm progressed county by county across the U.S. where oil and natural gas production occurred in 2012 to identify all co-located wells in the U.S. The number of new well completions and recompletions in 2012 was about 44,000, which includes oil and natural gas wells whether they were hydraulically fractured or not. All wells producing in 2012 numbered about 1.27 million. The second algorithm processed the results of the first such that wells can only appear once on a modelled well site.

Once these algorithms were complete and produced a results file we converted the results into a "kml" file that enabled the visual inspection of the results within Google Earth. While it was not possible to visually inspect every site in the U.S. linked to a 2012 completion or recompletion, as they numbered greater than 20,000, we examined sites randomly across a range of oil and natural gas production regions. The results of this visual examination indicated the algorithms were functioning as intended.

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[41] Drilling Information, Inc. 2011. *DI Desktop.* 2011 Production Information Database.
[42] Ibid.
[43] See the website <http://www.r-project.org/> for more information on R.

We estimated the number of wells per site assuming sites of one, two and three acres, based upon input from petroleum industry data analysts. Table 5-2 shows the high-level results of these analyses.

Table 5-2. Estimated Average Number of Wells per Well Site in 2012

Assumed Well Site Size	No. of Well Sites	No. of Wells at Sites	Average of Wells Per Site
One Acre	29,213	50,559	1.73
Two Acres	28,938	52,422	1.81
Three Acres	28,710	53,981	1.88

For assumed well sites of two acres, the analysis identified 28,938 independent well sites that contained 52,422 wells (including both single and multi-well sites). The total number of wells identified as being co-located with new well completions and recompletions exceeds the total number of completions and recompletions because the sites include about 8,500 existing wells producing in 2012.

However, the high level summary presented in Table X masks variation by basins and well types. Table 5-3 presents more detail along these dimensions for the assumed two-acre well site.

Table 5-3. Estimated Average Number of Wells per Two Acre Site of New Well Completion and Recompletion in 2012, by HPDI Basin and Type of Well (Oil or Natural Gas, Hydraulically Fractured or Not)

HPDI Basin	No. Of Sites	Oil Well Completions			Natural Gas Well Completions			Total
		HF	Not HF	All	HF	Not HF	All	
Los Angeles	23	N/A	13.07	13.07	N/A	N/A	N/A	13.07
Piceance	111	2.00	1.00	1.75	6.72	11.75	10.14	9.84
Arctic Ocean	2	N/A	5.50	5.50	N/A	N/A	N/A	5.50
Green River	164	2.23	1.57	2.01	4.37	1.13	4.19	3.88
Unidentified	226	1.18	3.57	3.38	1.00	1.77	1.44	3.22
San Joaquin Basin	1,745	1.56	3.46	3.21	2.61	1.42	2.24	3.16
Arkoma Basin	374	4.00	1.33	2.00	3.06	1.00	3.01	3.00
Denver Julesburg	826	2.63	3.10	2.75	1.48	3.14	1.72	2.46
Ft Worth Basin	1,305	2.05	1.86	1.91	3.27	1.10	2.93	2.33

HPDI Basin	No. Of Sites	Oil Well Completions			Natural Gas Well Completions			Total
		HF	Not HF	All	HF	Not HF	All	
Central Western Overthrust	7	1.50	N/A	1.50	2.60	N/A	2.60	2.29
Ventura Basin	1	N/A	2.00	2.00	N/A	N/A	N/A	2.00
Arctic Slope	42	N/A	2.13	2.13	N/A	1.65	1.65	1.99
Ouachita Folded Belt	181	2.01	1.90	1.99	1.50	1.00	1.43	1.97
Salina Basin	13	N/A	1.92	1.92	N/A	N/A	N/A	1.92
Palo Duro Basin	81	1.42	1.97	1.89	1.00	N/A	1.00	1.86
Uinta	548	1.16	1.33	1.32	N/A	3.33	3.33	1.83
Texas & Louisiana Gulf Coast	3,994	2.03	1.82	1.96	1.37	1.14	1.28	1.79
Central Kansas Uplift	450	N/A	1.78	1.78	N/A	1.53	1.53	1.77
Permian Basin	8,507	1.66	1.76	1.69	1.50	1.57	1.52	1.68
Sedgwick Basin	240	N/A	1.67	1.67	1.67	1.55	1.55	1.62
Las Animas Arch	25	1.00	1.64	1.61	N/A	1.50	1.50	1.60
Nemaha Anticline	38	N/A	1.55	1.55	N/A	N/A	N/A	1.55
Arkla Basin	811	1.09	1.57	1.49	1.47	1.09	1.42	1.46
Chautauqua Platform	461	1.36	1.57	1.49	1.64	1.03	1.35	1.45
Cook Inlet Basin	9	N/A	2.00	2.00	N/A	1.29	1.29	1.44
Appalachian	2,496	1.14	1.05	1.10	2.28	1.10	1.77	1.43
Williston	1,570	1.36	1.00	1.35	1.43	1.00	1.39	1.35
Cherokee Basin	271	1.17	1.29	1.29	N/A	1.69	1.69	1.35
San Juan	158	1.00	1.00	1.00	1.38	1.20	1.37	1.31
East Texas Basin	618	1.25	1.74	1.52	1.22	1.06	1.21	1.31
Forest City Basin	172	N/A	1.28	1.28	N/A	N/A	N/A	1.28
Anadarko Basin	2,663	1.17	1.77	1.37	1.09	1.29	1.13	1.27
South Oklahoma Folded Belt	167	1.17	1.36	1.30	1.11	1.11	1.11	1.24
Chadron Arch	49	N/A	1.22	1.22	N/A	N/A	N/A	1.22
Sacramento Basin	13	N/A	N/A	N/A	N/A	1.15	1.15	1.15
Mississippi & Alabama Gulf Coast	132	1.00	1.18	1.14	1.00	1.00	1.00	1.14
Central Montana Uplift	10	1.13	1.00	1.10	N/A	N/A	N/A	1.10

HPDI Basin	No. Of Sites	Oil Well Completions			Natural Gas Well Completions			Total
		HF	Not HF	All	HF	Not HF	All	
Big Horn	30	1.10	1.11	1.11	1.00	N/A	1.00	1.10
Powder River	232	1.15	1.03	1.12	1.05	1.00	1.04	1.10
Sweet Grass Arch	17	1.00	1.08	1.05	1.50	1.00	1.33	1.10
Paradox	13	1.00	1.10	1.09	1.00	N/A	1.00	1.08
Black Warrior Basin	57	1.00	1.00	1.00	1.00	1.75	1.07	1.05
Wind River	63	1.00	1.02	1.02	1.00	1.00	1.00	1.02
Wasatch Uplift	1	N/A	1.00	1.00	N/A	N/A	N/A	1.00
North Park	2	1.00	1.00	1.00	N/A	N/A	N/A	1.00
Raton	20	N/A	N/A	N/A	1.00	1.00	1.00	1.00
Grand Total	**28,938**	**1.64**	**1.99**	**1.79**	**1.90**	**1.76**	**1.86**	**1.81**

What is evident in Table 5.3 is that the concentration of wells at production sites varies greatly by basin. However, the analysis indicates that most wells sites have relatively few or no co-located wells, which brings the national average wells per new completion or recompletion site to 1.81 for the two-acre well site. While the analysis shows variation by basin, at the national-level, there is relatively little variation across oil and natural gas well completion sites and whether the new wells were completed or recompleted using hydraulic fracturing. For example, oil well sites averaged 1.79 wells per site while natural gas wells averaged 1.86.

As a result of this analysis, based upon professional judgement, we decided to use the two-acre well site as the assumed maximum size of a site to estimate the number of wells co-located at sites of new completions and recompletions. Also, to simplify analysis of costs and emissions at well sites, we rounded the 1.81 national average wells per site to 2.00.

While we are confident that the assumed two acre well site is a reasonable size to capture most co-located wells in 2012, it is by no means a perfect assumption. First, industry and state regulatory trends indicate that well drilling will likely become increasingly concentrated on sites, potentially leading to an increase in the average number of wells per well site. However, it is not possible at this point to forecast this increasing concentration, especially with the variations by fields described above. Also, it is possible that two acres is too small to accurately estimate the number of co-located wells for large well sites in some fields. As a result, the algorithms might result in an under-estimate of the average number of wells at a site and identify more than one site when in actuality there is only one.

Alternatively, the assumed two acre might over-estimate the size of sites in some fields and, as a result, pull in more than one site, overestimating the number of wells on the site. We also noted that the latitude and longitudes on many wells were likely incorrect or exact duplicates of other wells. Despite these caveats, we believe that the well site analysis described here produces a reasonable estimate of national average of number of wells on new well completion and recompletion sites in 2012.

For natural gas production well sites, the model plant was developed using the average fugitive emissions components counts for gas production data from the GRI/EPA report. The average component count for a gas well was estimated by weighting the average of component counts for the Eastern and Western U.S. data sets for gas production equipment. The weighted averages of the data sets were determined to be 1.6 separators, 0.8 meters/piping, 0.8 in-line heaters, and 0.6 dehydrators per well. The total natural gas production well site component counts were calculated by multiplying the average well component values by the average number of wells per well site (2), and rounding the product to the nearest integer. Average 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 study. The total number of fugitive emissions components was calculated by multiplying the rounded component counts by the component count per production 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 5-4.

For oil production well sites, the model plant was developed using component counts from an API workbook and component count data from the GRI/EPA study. The average component count for an oil well were determined to be 0.7 separators, 0.7 headers, and 0.03 heater/treaters per well. The total oil production well site component counts were calculated by multiplying the average well production equipment values by the average number of oil wells per oil well site (2), and rounding the product to the nearest integer. Average component counts obtained from the API workbook were used to calculate the total number of components by multiplying the rounded component counts by the component count per production equipment and rounding up to the nearest integer. A summary of the fugitive emissions component counts for oil production well sites is presented in Table 5-5.

Baseline model plant emissions for the natural gas and oil production well sites were calculated using the fugitive emissions component counts and the component oil and natural gas production emission factors from AP-42[44]. Annual emissions were calculated assuming 8,760 hours of operation

[44] U.S. EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)

each year. The emissions factors are provided for total organic compounds (TOC) and include non-VOCs such as CH_4 and ethane. The emission factors used to estimate the new source emissions from the production segment (e.g., oil production well sites, natural gas production well sites, gathering and boosting stations) are presented in Table 5-6.

Emissions of VOC were calculated using weight ratios for VOC/TOC as described in the 2011 Gas Composition Memorandum developed for the 2012 NSPS[45]. A summary of the fugitive emissions component counts, average CH_4 emissions factors, CH_4 emissions and VOC emissions for natural gas and oil production well sites is provided in Tables 5-7 and 5-8, respectively. The average fugitive emissions from a gas well model plant were determined to be 4.54 tpy of CH_4 and 1.26 tpy of VOC and the average fugitive emissions from an oil well model plant was determined to be 1.09 tpy of CH_4 and 0.30 tpy of VOC. These emissions were used to estimate the potential emission reductions and cost of control of a fugitive emissions reduction program.

The estimates presented here were developed using average emission factors for typical components of the process equipment present at well sites, and average values for equipment counts per well site. Many studies have shown a skewed distribution for emissions related to leaks, where a majority of emissions come from a minority of sources. This means that some sources have emissions significantly higher than would be calculated using average emission factors and average component types. Sources included in the subset of a data set that contributes to the majority of emissions are sometimes referred to as "gross emitters" or "super emitters." These gross emitters have been observed among groups of components within a site, among groups of entire facilities, and within data sets of components of the same type across a number of sites or facilities.

Of the data sources presented in the white paper, all of the sources with full data sets available exhibited skewed distributions, including the Allen et al. (2013) data set on well site fugitives, and the ERG City of Fort Worth study, in which 20% of the surveyed well sites accounted for 80% of total emissions. Both studies by Clearstone Engineering, Ltd. showed skewed distributions of leak emissions at processing plants, and the two mobile measurement studies observed skewed distributions at well sites. Since publication of the white paper, additional data have become available on fugitive emissions at well sites, including reporting year 2013 data from GHGRP, which included onshore production fugitive emissions of 8,719,385 tons CO_2e of methane from reporters.

[45] 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.

5.2.2.2 Gathering and Boosting Station

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 production equipment) to well sites; however they are not directly connected to the wellheads. The gathering and boosting station model plant was developed using the average fugitive emissions component counts for onshore production from the GRI/EPA study. The average component count for a gathering and boosting station was estimated by weighting the average of component counts for the Eastern and Western U.S. data sets for onshore production equipment. 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. Fugitive emissions 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 study. The components for gathering compressors were included in the model plant total counts, but the compressor seals were excluded. Compressors seals are addressed in a 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 5-9.

Baseline emissions were calculated using the component counts and the CH_4 emission factors for oil and natural gas production (See Table A-3). The baseline emissions for gathering and boosting stations are summarized in Table 5-10. The average fugitive emissions from a gathering and boosting station were determined to be 35.1 tpy of CH_4 and 9.77 tpy of VOC. These emissions were used to estimate the potential emission reductions and cost of control of a fugitive emissions reduction program.

Since publication of the white paper, additional data have become available on fugitive emissions from compressor stations, including data from the Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants: Measurement Results study published in 2015.[46] This study measured facility-level emissions, including fugitive emissions, at gathering and processing facilities. Data sets for both facility types had skewed distributions. In the study data sets, 30% of gathering facilities contributed 80% of the total emissions, and gathering facilities emitted, on average yielded higher emissions than would be calculated with the factors used in this analysis.

[46] Mitchell, Austin L. et al. *Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants: Measurement Results.* Environ. Sci.Technol. 2015, 2119-3227.

Table 5-4. Average Fugitive Emissions Component Count for Gas Production 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	Connectors	OELs	PRVs	Valves	Connectors	OELs	PRVs
Gas Wellheads	2	9	37	1	0	19	74	1	0
Separators	2	22	68	4	1	43	137	7	2
Meters/Piping	1	13	48	0	0	13	48	0	0
In-Line Heaters	1	14	65	2	1	14	65	2	1
Dehydrators	1	24	90	2	2	24	90	2	2
					Total	113	414	12	5
					Rounded up Total	114	414	14	6

a. Data Source: EPA/GRI, CH_4 Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

Table 5-5. Average Fugitive Emissions Component Count for Oil Production 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	Connectors	OELs	PRVs	Valves	Connectors	OELs	PRVs
Oil Wellheads	2	5	18	0	0	10	36	0	0
Separators	1	6	22	0	0	6	22	0	0
Headers	1	5	14	0	0	5	14	0	0
Heater/treaters	1	8	32	0	0	8	32	0	0
					Total	29	104	0	0
					Rounded up Total	29	104	1	1

a. Data Source: EPA/GRI, CH_4 Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

Table 5-6. Oil and Gas Production Operations Average Emissions Factors

Component Type	Component Service	Emission Factor[a] (kg/hr/source)
Valves	Gas	4.5E-03
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)

Table 5-7. Estimated Fugitive Emission Estimate for Natural Gas Production 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)	
			CH_4[c]	VOC[d]
Valves	114	0.0045	3.442	0.957
Connectors	414	0.0002	0.555	0.154
OELs	14	0.002	0.188	0.052
PRVs	6	0.0088	0.354	0.098
		Total	4.54	1.26

[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. CH_4 emissions calculated using 0.695 weight ratio for CH_4/TOC obtained from gas composition memorandum.
d. VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from gas composition memorandum.

Table 5-8. Estimated Fugitive Emission Estimate for Oil Production 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)	
			CH_4[c]	VOC[d]
Valves	29	0.0045	0.876	0.243
Connectors	104	0.0002	0.140	0.039
OELs	1	0.002	0.013	0.004
PRVs	1	0.0088	0.059	0.016
		Total	1.09	0.302

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. CH_4 emissions calculated using 0.695 weight ratio for CH_4/TOC obtained from gas composition memorandum.
d. VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from gas composition memorandum.

Table 5-9. 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 up 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 5-10. Estimated Fugitive Emission Estimate 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)	
			CH_4[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 CH_4/TOC obtained from gas composition memorandum.
c. VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from gas composition memorandum.

5.2.2.3 Natural Gas Transmission and Storage

Natural gas transmission and storage stations are facilities that use compressors that 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 compression 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 compressors or gathering and boosting stations. Fugitive emissions component counts and CH_4 emission factors were obtained from the EPA/GRI study. A summary of the fugitive emissions component counts, component emission factors and baseline CH_4 and VOC emissions for transmission and storage model plants are presented in Table 5-11. The average fugitive emissions for transmission stations were determined to be 62.4 tpy of CH_4 and 1.73 tpy of VOC and 164.4 tpy of CH_4 and 4.55 tpy 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 5-11. Estimated Fugitive Emission Estimate for Oil and Natural Gas Transmission and Storage Model Plant

Component	Model Plant Component Count[a]	Component CH_4 Emission Factor[a] (Mscf/year/component)	CH_4 Emissions[b] (tpy)	VOC Emissions[c] (tpy)
Transmission Facility				
Valve	673	0.867	12.1	0.366
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
Site Blowdown OEL	4	264	22.0	0.608
		Total	62.4	1.73
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	2.277
PRV	66	6.2	8.52	0.236
Site Blowdown OEL	4	264	22.0	0.608
Valve (Inj/With)	30	0.918	0.57	0.016
Connector (Inj/With)	89	0.125	0.23	0.006

Component	Model Plant Component Count[a]	Component CH_4 Emission Factor[a] (Mscf/year/component)	CH_4 Emissions[b] (tpy)	VOC Emissions[c] (tpy)
OEL (Inj/With)	7	0.237	0.03	0.001
PRV (Inj/With)	1	1.464	0.03	0.001
		Total	164.4	4.55

a. Component counts and CH_4 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 CH_4 emission factor and converting to tons using the conversion factor 0.02082 tons CH_4/Mscf CH_4.
c. VOC emissions calculated using 0.0277 weight ratio for VOC/CH_4 obtained from Gas Composition memorandum.

5.3 Nationwide Emissions from New Sources

5.3.1 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 approach for estimating emissions. Baseline model plant emissions for the oil and natural gas production and transmission and storage segments were calculated using the equipment and fugitive emissions component counts and the representative gas service emission factors. Emissions were estimated using the EPA Protocol for Equipment Leak Emission Estimates which provided TOC emission factors for production sources (well sites, gathering and boosting) and the GRI/EPA study which provided CH_4 emission factors for transmission and storage facilities. The VOC emissions were calculated using weight fractions provided in the gas composition memorandum.

5.3.2 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, GHG Inventory were used to estimate the number of new well sites, gathering and boosting stations, and transmission and storage facilities. 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.

5.3.2.1 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, we 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 State 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). Inspections can be conducted using Method 21. AVO and an infra-red camera may also be used for monitoring where a leak is defined as any detectable emissions that are not associated with normal equipment operation (e.g. pneumatic device actuation)[47]
- 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. [48]
- 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 audio-visual-olfactory (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.).[49]

- Utah: On June 5, 2014, Utah Department of Environmental Quality approved a "General Approval

[47] Colorado regulations available at https://www.colorado.gov/pacific/sites/default/files/5-CCR-1001-9_0.pdf.
[48] 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.
[49] Wyoming regulations are available at http://soswy.state.wy.us/Rules/RULES/9868.pdf.

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.[50]

Based on the above information, we determined that well sites in these states would already be subject to State leak requirements and would not be subject to the NSPS. According to our analysis, 21 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 2 natural gas wells per well site, the number of new well sites in 2012 was estimated to be 3,346. An annual growth rate of 6.45 percent, which was determined from the NEMS data, was applied to the total number of new natural gas well completions, both conventional and hydraulically fractured in 2012, and 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. The projected number of new natural gas well sites was estimated to be 5,518 in 2020. 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, or 38,933 well sites 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.

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 9 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 32,284 new oil wells were not covered by state leak regulations in 2012. Assuming 2 oil production wells per well site, the number of new oil production well sites was determined to be 16,142 in 2012. An annual growth rate of 0.32 percent, which was determined from the NEMS data, was applied to the total number of new oil well completions, both conventional and hydraulically fractured in 2012, and used to estimate the number of new oil well sites in the years 2020 and 2025. The percentage of wells covered by State leak regulations, and the 2 oil wells per well site assumptions were applied to

[50] Utah regulations are available at http://www.deq.utah.gov/Permits/GAOs/docs/2014/6June/DAQE-AN149250001-14.pdf.

these totals to estimate the number of new oil well production sites. The projected number of new oil well sites was estimated to be 16,562 in 2020. 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, or 100,175 well sites in 2025. This approach was used to support the regulatory impacts assessment process to reflect rule impacts from the effective date through 2025. These estimated well site values were used to calculate the nationwide fugitive emissions from oil production well sites in 2012, 2020 and 2025.

5.3.2.2 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 GRI/EPA document does not include a separate list of compressor counts 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, we used an annual growth rate of 3 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 259 new gathering and boosting stations each year that would be affected sources under the proposed NSPS in each of the years 2012 and 2020. 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. This approach was used to support the regulatory impacts assessment process to reflect rule impacts from the effective date through 2025.

5.3.2.3 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 2012 estimated in the GHG Inventory and determining the rate of change in the number of these facilities over this period. For all the years, the annual number of new transmission stations was determined to be 24 and the annual change in storage facilities was determined to be 16. The average change for the last 10 years was also reviewed and the annual number of new transmission stations was determined to be 6 and the annual number of storage facilities was determined to be 15. Because of the fluctuation (both positive and negative) in the number of new transmission and storage stations from the years 1990 to 2012, it is assumed that the 10-year average change represents a better estimate of the current growth of the transmission and storage segment, therefore it will be assumed that there will 6 new transmission stations and 15 new storage stations each year that would be affected sources under the proposed NSPS in each of the years 2012 and 2020. 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. This approach was used to support the regulatory impacts assessment process to reflect rule impacts from the effective date through 2025.

5.3.3 Emission Estimates

The nationwide emissions were calculated using the model plant data and the estimated number of new 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 5-12. The summary includes baseline emissions for each of these segments for projected years 2020 and 2025.

Table 5-12. 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	CH_4 Emissions (tpy)	VOC Emissions (tpy)
Base Year 2012			
Natural Gas Well Sites	3,346	15,188	4,222
Oil Well Sites	16,142	17,555	4,880
Gathering & Boosting Stations	259	9,102	2,530
Transmission Stations	6	374	10.4
Storage Stations	15	2,466	68
Projected Year 2020			
Natural Gas Well Sites	5,518	25,048	6,963
Oil Well Sites	16,562	18,011	5,007
Gathering & Boosting Stations	259	9,102	2,530
Transmission Stations	6	374	10.4
Storage Stations	15	2,466	68
Projected Year 2025			
Natural Gas Well Sites	38,933	176,726	49,125
Oil Well Sites	100,175	108,942	30,283
Gathering & Boosting Stations	1,554	54,612	15,181
Transmission Stations	36	2245	62.1
Storage Stations	90	14,798	410

5.4 Control Techniques

5.4.1 Potential Control Techniques

The EPA has determined that fugitive emissions from fugitive emissions components, such as valves, OELs, PRVs, thief hatches, pumps, and connectors, are a significant source of CH_4, VOC and HAP emissions from oil and natural gas facilities. Previously, during development of the NSPS, the cost of using EPA Method 21 for leak detection combined with leak correction program was evaluated for the oil and natural gas source category and it was determined that the cost of control for use of this method was not reasonable for the production, gathering and boosting, and transmission and storage segments. However, we noted that we would continue to review available data and information to determine if these sources should be addressed in future rulemaking.

Many of the fugitive emission measurements presented in the equipment leaks white paper were conducted with EPA Method 21 instruments (e.g., OVA, flame ionization detector, flow measurement devices). In addition to EPA Method 21 analyzers, several studies conducted fugitive emission surveys using OGI in conjunction with portable Method 21 analyzers and gas chromatograph equipment to measure individual VOC and HAP compounds. These studies provided emission estimates in the form of component or equipment emission factors or emission estimates by facility. Even though there is a wide variation in the potential CH_4 and VOC emissions, the studies showed that there are economic options for reducing these emissions.

The detection of fugitive emissions from these sources can be determined using several technologies. Historically, fugitive emissions were detected using EPA Method 21 portable analyzers to determine if a leak exceeded a set threshold (e.g., the leak concentration was greater than the leak definition for the component). As described in the white paper, we believe that many fugitive emission surveys are now conducted using OGI which is a technology that operates much like a consumer video-camcorder and provides a real-time visual image of hydrocarbon gas emissions or leaks to the atmosphere. The OGI camera works by using spectral wavelength filtering and an array of IR detectors to visualize the IR absorption of hydrocarbons and other gaseous compounds. As the gas absorbs radiant energy at the same waveband that the filter transmits to the detector, the gas and motion of the gas is imaged. The OGI instrument can be used for monitoring a large array of equipment and components at a facility, and is an effective means of detecting fugitive emissions when the technology is used appropriately. Several studies in the white paper estimated that OGI can monitor 1,875-2,100 components per hour. In comparison, the average screening rate using a hand-held toxic vapor analyzers (TVA) or OVA is roughly 700 components per day. However, the EPA's recent work with OGI systems suggests these studies underestimate the amount of time necessary to thoroughly monitor components for fugitive emissions using OGI technology. Even though the amount of time may be underestimated, it is believed that the OGI system can reduce the cost of identifying fugitive emissions at oil and natural gas facilities when compared to using a handheld TVA or OVA. Another study in the white paper analyzed 4,293 leak detection surveys completed for the oil and gas industry using OGI systems and found the average abatement cost to be approximately $0 per ton of VOC and approximately -$375 per ton of VOC for well sites and compressor stations respectively. These estimates assume all leaks that are found are repaired and the recovered CH_4 can be sold for $4/Mcf.

Based on the review of the public and peer review comments on the white paper and the Colorado and Wyoming state rules, two options for reducing CH_4 and VOC emissions from fugitive emissions components were identified: a fugitive emissions monitoring program based on the use of OGI combined with repair of the components that are found to have fugitive emissions and a fugitive emissions monitoring program based on individual component monitoring using EPA Method 21 for the detection of fugitive emissions combined repair of the components that are found to have fugitive emissions. Several public and peer reviewer comments on the white paper noted that these technologies are currently used by industry to reduce fugitive emissions from the production segment in the oil and natural gas industry. The costs and potential emissions reductions for both of these options depends on the frequency of the monitoring and the required repair threshold. For our analysis of the EPA Method 21 option, we can evaluate three leak repair thresholds: 500 ppm, 2,500 ppm and 10,000 ppm. For the OGI monitoring analysis, we conclude that any visible emissions that are imaged by the OGI instrument is a fugitive emission. Proper operation of the OGI instrument is critical for finding fugitive emissions; therefore, several operating procedures, such as daily verification check, determination of the maximum viewing distance from the components, and determination of the maximum wind speed during which monitoring can take place, are required. For all options we evaluated quarterly, semiannual and annual monitoring frequency. The following sections describe our evaluation to determine the potential emission reductions and the cost of control for these options.

5.4.2 Fugitive Emissions Detection and Correction with OGI

5.4.2.1 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 monitoring is conducted using OGI. The company may use a corporate-wide monitoring plan that covers the collection of fugitive emissions components at well sites or compressor stations corporate-wide in conjunction with a plan that is site-specific to each collection of fugitive emissions components at well sites and compressor stations. As an alternative, an operator may develop a site-specific plan for each collection of fugitive emissions components that contains the requirements of the corporate-wide and site specific plans. 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 and any other component known to have potential to have fugitive emissions. The plan must also 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). The OGI instrument that is used to conduct monitoring surveys must be capable of imaging gas that is half methane and half propane at a concentration of 10,000 ppm at a flow rate of ≥60 g/hr from a quarter inch diameter orifice. These criteria are based on the EPA's recent work with OGI systems indicating that fugitive emissions at a concentration of at least 10,000 ppm are generally detectible using OGI with proper monitoring and operating practices. In order to estimate the cost of implementation of a monitoring and repair plan, we need to estimate the cost of repair, which is based on the number of components found to have fugitive emissions. Although with OGI the operator would not be able to determine the exact concentration of the fugitive emissions, all identified fugitive emissions would be required to be repaired. Because the repair threshold impacts the number of components repaired, and therefore, the cost of implementing the plan, for the purposes of our analysis, repair means that no visible emissions are observed when the fugitive emissions component is resurveyed using OGI. . The options to reduce emissions would then vary based on the frequency of the monitoring/repair of the components. If a fugitive emissions component cannot be immediately repaired during the monitoring survey, the operator must repair the component within 15 days of finding fugitive emissions. For this resurvey, the operator may use either OGI or Method 21 to confirm that the component is no longer emitted 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.

5.4.2.2 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 (e.g., open thief hatches, open dump valves, etc.) during the OGI survey and other 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 Commission[51] 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, we expect the emission reductions from the implementation of an OGI monitoring and repair program to vary depending on the frequency of monitoring. For this analysis, we estimated emissions reductions for the OGI monitoring frequency options (annual, semiannual and quarterly) using the estimated emission reductions from Colorado's Economic Impact Analysis for conducting the OGI monitoring and repair program. Based on this range of expected emission reductions as characterized by Colorado's Economic Impact Analysis, it is expected that an OGI monitoring program in combination with a repair program can reduce fugitive CH_4 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. Table 5-13 summarizes the estimated nationwide baseline emission reductions from a monitoring and repair program using an OGI monitoring and repair plan for the various segments. See tables A-33 through A-60 in Appendix A for detailed calculations of emissions, reductions, cost of control and nationwide impacts.

[51] Colorado Air Quality Control Commission, *Initial Economic Impact Analysis for Proposed Revisions to Regulation Number 7 (5 CCR 1001-9).* November 15, 2013.

Table 5-13. Nationwide Emission Reductions for OGI Monitoring and Repair Plan Options for 2020 and 2025

Oil and Gas Segment	Number of New Facilities	Annual Monitoring (tpy)[a]		Semiannual Monitoring (tpy)[a]		Quarterly Monitoring (tpy)[a]	
		CH_4	VOC	CH_4	VOC	CH_4	VOC
Base Year 2012							
Natural Gas Well Sites	3,346	6,075	1,689	9,101	2,533	12,151	3,378
Oil Well Sites	16,142	7,022	1,952	10,492	2,922	14,044	3,904
Gathering & Boosting Stations	259	3,641	1,012	5,461	1,518	7,282	2,024
Transmission Stations	6	150	4	225	6	299	8
Storage Stations	15	987	27	1,480	41	1,973	55
Projected Year 2020							
Natural Gas Well Sites	5,518	10,019	2,785	15,029	4,178	20,038	5,570
Oil Well Sites	16,562	7,205	2,003	10,807	3,004	14,409	4,005
Gathering & Boosting Stations	259	3,641	1,012	5,461	1,518	7,282	2,024
Transmission Stations	6	150	4	225	6	299	8
Storage Stations	15	987	27	1,480	41	1,973	55
Projected Year 2025							
Natural Gas Well Sites	38,933	69,710	19,378	106,036	29,475	139,420	38,755
Oil Well Sites	100,175	43,577	12,113	65,365	18,170	87,153	24,226
Gathering & Boosting Stations	1,554	21,845	6,072	32,767	9,108	43,689	12,144
Transmission Stations	36	898	25	1,347	37	1,796	50
Storage Stations	90	5,919	164	8,879	246	11,838	328

a. Assumes 40% reduction with the implementation of annual IR camera monitoring, 60% reduction with the implementation of semi-annual IR camera monitoring and 80% with the implementation of quarterly IR camera monitoring.

5.4.2.3 Cost Impacts

Costs for preparing an OGI fugitive emission monitoring and repair plan on a company level were estimated using hourly estimates for each of the plan elements. The costs are based on the following assumptions:

- 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 \$231.20

- 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 32 hours to complete at a cost of $1,849.
- Notification of compliance status was estimated to take 1 person 1 hour to complete at a cost of $58 for gathering and boosting stations, transmission stations, and storage facilities. For companies that own and operate production well sites, the cost notification of compliance status was estimated to be $58 per well site for a company that owns 22 well sites for a total of $1,272 per company.
- Cost of a Method 21 Monitoring Device of $10,800.
- Subsequent activities planning are estimated to take 2 people a total of 12 hours to complete at a cost of $1,387. For oil and natural gas production well sites, this cost was divided among the total number of well sites owned by a company, which was assumed to be 22. The cost per well site was estimated to be $63.

Costs for implementing a fugitive emission monitoring plan on a company level were estimated for each of the monitoring and repair elements. The costs are based on the following assumptions:

- The cost for OGI monitoring using an outside contractor was assumed to be $600 for a well production site and $2,300 for a gathering and boosting station, a transmission station and a storage facility.[52]
- Annual repair costs were estimated to be $597 for production well sites, $6,871 for gathering and boosting stations, $6,721 for transmission stations, and $13,892 for storage facilities. These costs were estimated assuming that 1.18% of the components leak[53] and 75% are repaired online and 25% are repaired offline.
- Cost to resurvey the repaired components using a Method 21 device that could not be fixed during the initial survey based on $2.00 per component. This is based on the assumption that a company

[52] Costs for contractor based OGI monitoring obtained from the Carbon Limits report.

[53] 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 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).

purchases Method 21 instrumentation (estimated to be $10,800[54]) and is able to perform the resurvey without retaining contractors.

- 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 production 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. Assuming that each company owns and operates 22 well sites[55], the capital cost per well site was estimated to be $801. For gathering and boosting, transmission and storage compressor stations 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 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 submittal of an annual report, and the amortized capital cost over 8 years at 7 percent interest. For our analysis we calculated the annual cost for annual, semiannual and quarterly OGI surveys. Tables 5-14, 5-15 and 5-16 summarizes the annual cost for each segment at each of the three survey frequencies. Tables A-7 through A-10 in Appendix A present the analysis for the estimated annual cost of implementing an OGI monitoring and repair program for oil and natural gas production 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 each pollutant separately (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., CH_4 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 CH_4 and VOC are equal; and therefore the proration of the annual cost was divided equally and applied to the CH_4 and VOC reductions.

[54] 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

[55] The number of well sites owned and operated by companies was calculated using data from the Fort Worth study.

Based on estimated emissions reductions and the estimated cost for implementing an OGI fugitive emissions monitoring and repair program at the affected facilities, we calculated a cost of control for CH_4 and VOC for the various options for oil and natural gas production well sites, gathering and boosting, transmission and storage compressor stations. We then calculated the cost of control of well sites and compressor stations using the weighted average cost of control all well sites and all compressor stations (i.e., gathering and boosting, transmission and storage). Table 5-14, 5-15 and 5-16 presents a summary of the cost of control for CH_4 and VOC for the three OGI monitoring frequency options (i.e., annual, semiannual and quarterly, respectively) based on the single-pollutant method of 100 percent of the cost being attributed to the individual pollutants. Tables 5-17, 5-18 and 5-19 present a summary of the capital and annual costs, and the cost of control for CH_4 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). See Tables A-33 through A-60 in Appendix A for detail on the emissions, reductions and cost of control calculations for the various options for each segment.

5.4.2.4 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 IR camera monitoring contractors with respect to driving to and from the site for the fugitive emissions survey however, these emissions cannot be quantified because there is no data related to the distance that would need to be traveled to the site. However, it is believed that the secondary impacts expected from the implementation of an OGI monitoring program would be minimal.

Table 5-14. Summary of the Model Plant Cost of Control for the Annual OGI Monitoring Option - Single-Pollutant

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]	1.82	0.50	$801	$1,329	$908	$732	$2,633	$500	$1,799
Oil Production Well Site[d]	0.44	0.12	$801	$1,329	$1,228	$3,055	$10,992	$2,824	$10,158
Well Site Program Weighted Average[h]						$2,475	$8,903	$2,243	$8,069
Gathering & Boosting Station[e]	14.1	3.9	$16,407	$10,124	$6,865	$720	$2,591	$488	$1,757
Transmission Station[f]	24.9	0.7	$16,407	$10,049	$4,882	$403	$14,554	$403	$14,554
Storage Facility[g]	65.8	1.8	$16,407	$13,634	$15	$207	$7,491	$207	$7,491
Compressor Stations Program Weighted Average[h]						$686	$3,110	$471	$2,338

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 $17,620 divided between an average of 22 well sites per company. The capital cost for the gathering and boosting, 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 CH_4 reductions, CH_4 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 $1,195 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 $7,301 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 $10,866and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2020 activity counts of 5518 gas well sites, 16562 oil well sites, 259 G&B stations, 6 transmission stations and 15 storage facilities.
Note: Transmission and storage facilities do not own the natural gas; therefore cost benefits from reducing the amount of natural gas as the result of equipment leaks was not estimated for the transmission and storage segment.

Table 5-15. Summary of the Model Plant Cost of Control for the Semiannual OGI Monitoring Option -Single-Pollutant

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]	2.72	0.76	$801	$2,230	$1,599	$819	$2,945	$587	$2,111
Oil Production Well Site[d]	0.65	0.18	$801	$2,230	$2,079	$3,417	$12,294	$3,186	$11,460
Well Site Program Weighted Average[h]						$2,768	$9,958	$2,536	$9,124
Gathering & Boosting Station[e]	21.1	5.9	$16,407	$15,881	$10,993	$753	$2,710	$521	$1,876
Transmission Station[f]	37.4	1.0	$16,407	$15,732	$7,982	$420	$15,190	$420	$15,190
Storage Facility[g]	98.7	2.7	$16,407	$22,902	$2,473	$232	$8,388	$232	$8,388
Compressor Stations Program Weighted Average[h]						$718	$3,281	$504	$2,510

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 the gathering and boosting, 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 CH_4 reductions, CH_4 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 $2,096 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 $12,984 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 $20,154 and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2020 activity counts of 5518 gas well sites, 16562 oil well sites, 259 G&B stations, 6 transmission stations and 15 storage facilities.
Note: Transmission and storage facilities do not own the natural gas; therefore cost benefits from reducing the amount of natural gas as the result of equipment leaks was not estimated for the transmission and storage segment.

Table 5-16. Summary of the Model Plant Cost of Control for the Quarterly OGI Monitoring Option -Single-Pollutant

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]	3.63	1.01	$801	$4,031	$3,190	$1,110	$3,994	$878	$3,160
Oil Production Well Site[d]	0.87	0.24	$801	$4,031	$3,830	$4,634	$16,669	$4,402	$15,836
Well Site Program Weighted Average[h]						$3,753	$13,502	$3,521	$12,668
Gathering & Boosting Station[e]	28.1	7.8	$16,407	$27,396	$20,879	$974	$3,506	$743	$2,672
Transmission Station[f]	49.9	1.4	$16,407	$27,097	$16,765	$543	$19,623	$336	$12,140
Storage Facility[g]	131.5	3.6	$16,407	$41,437	$14,199	$315	$11,383	$108	$3,901
Compressor Stations Program Weighted Average[h]						$930	$4,273	$715	$3,502

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 $17,620 divided between an average of 22 well sites per company. The capital cost for the gathering and boosting, 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 CH_4 reductions, CH_4 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 $3,897 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 $24,350 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 $38,689 and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2020 activity counts of 5518 gas well sites, 16562 oil well sites, 259 G&B stations, 6 transmission stations and 15 storage facilities.
Note: Transmission and storage facilities do not own the natural gas; therefore cost benefits from reducing the amount of natural gas as the result of equipment leaks was not estimated for the transmission and storage segment.

Table 5-17. 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]	1.82	0.50	$801	$1,329	$908	$366	$1,317	$250	$900
Oil Production Well Site[d]	0.44	0.12	$801	$1,329	$1,228	$1,528	$5,496	$1,412	$5,079
Well Site Program Weighted Average[h]						$1,237	$4,451	$1,121	$4,035
Gathering & Boosting Station[e]	14.1	3.9	$16,407	$10,124	$6,865	$360	$1,295	$244	$878
Transmission Station[f]	24.9	0.7	$16,407	$10,049	$4,882	$201	$7,277	$201	$7,277
Storage Facility[g]	65.8	1.8	$16,407	$13,634	$15	$104	$3,745	$104	$3,745
Compressor Stations Program Weighted Average[h]						$343	$1,555	$236	$1,169

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 $17,620 divided between an average of 22 well sites per company. The capital cost for the gathering and boosting, 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 CH_4 reductions, CH_4 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 $1,195 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 $7,301 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 $10,866and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2020 activity counts of 5518 gas well sites, 16562 oil well sites, 259 G&B stations, 6 transmission stations and 15 storage facilities.
Note: Transmission and storage facilities do not own the natural gas; therefore cost benefits from reducing the amount of natural gas as the result of equipment leaks was not estimated for the transmission and storage segment.

Table 5-18. 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]	2.72	0.76	$801	$2,230	$1,599	$409	$1,473	$293	$1,056
Oil Production Well Site[d]	0.65	0.18	$801	$2,230	$2,079	$1,709	$6,147	$1,593	$5,730
Well Site Program Weighted Average[h]						$1,384	$4,979	$1,268	$4,562
Gathering & Boosting Station[e]	21.1	5.9	$16,407	$15,881	$10,993	$377	$1,355	$261	$938
Transmission Station[f]	37.4	1.0	$16,407	$15,732	$7,982	$210	$7,595	$210	$7,595
Storage Facility[g]	98.7	2.7	$16,407	$22,902	$2,473	$116	$4,194	$116	$4,194
Compressor Stations Program Weighted Average[h]						$359	$1,641	$252	$1,255

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 the gathering and boosting, 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 CH_4 reductions, CH_4 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 $2,096 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 $12,984 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 $20,154 and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2020 activity counts of 5518 gas well sites, 16,562 oil well sites, 259 G&B stations, 6 transmission stations and 15 storage facilities.
Note: Transmission and storage facilities do not own the natural gas; therefore cost benefits from reducing the amount of natural gas as the result of equipment leaks was not estimated for the transmission and storage segment.

Table 5-19. 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 Site[d]	3.63	1.01	$801	$4,031	$3,190	$555	$1,997	$439	$1,580
Oil Production Well Site[d]	0.87	0.24	$801	$4,031	$3,830	$2,317	$8,335	$2,201	$7,918
Well Site Program Weighted Average[h]						$1,877	$6,751	$1,761	$6,334
Gathering & Boosting Station[e]	28.1	7.8	$16,407	$27,396	$20,879	$487	$1,753	$371	$1,336
Transmission Station[f]	49.9	1.4	$16,407	$27,097	$16,765	$272	$9,812	$272	$9,812
Storage Facility[g]	131.5	3.6	$16,407	$41,437	$14,199	$158	$5,692	$158	$5,692
Compressor Stations Program Weighted Average[h]						$465	$2,136	$358	$1,751

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 $17,620 divided between an average of 22 well sites per company. The capital cost for the gathering and boosting, 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 CH_4 reductions, CH_4 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 $3,897 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 $24,350 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 $38,689 and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2020 activity counts of 5518 gas well sites, 16562 oil well sites, 259 G&B stations, 6 transmission stations and 15 storage facilities.
Note: Transmission and storage facilities do not own the natural gas; therefore cost benefits from reducing the amount of natural gas as the result of equipment leaks was not estimated for the transmission and storage segment.

5.4.3 Fugitive Emissions Detection and Correction with EPA Method 21

5.4.3.1 Description

Although we are not proposing to specifically allow the use of Method 21 to detect fugitive emissions from the collection of the fugitive emissions components at well sites and compressor stations, we have evaluated Method 21 as an option to allow comment on whether Method 21 should be allowed for fugitive emissions monitoring in the final rule. Under this option, the reduction of fugitive emissions from well sites, gathering and compressor stations (i.e., boosting stations, transmission and storage facilities) also involves the development of a fugitive emissions monitoring plan, except that the monitoring is conducted using EPA Method 21 instead of OGI, as described above. The Method 21 monitoring includes the development of fugitive emissions monitoring plan, surveying using Method 21 instrumentation, re-survey of repaired components and the preparation and submittal of an annual report. The company may use the same monitoring plan for all affected sources, a different plan for each category of a source, or a plan for each individual source. The monitoring plan must include inspection of the collection of fugitive emissions components, such as connectors, open-ended lines/valves, pressure relief devices, closed vent systems, compressors, and thief hatches. The plan must also include provisions to repair or replace fugitive emissions components as soon as practicable if evidence of fugitive emissions is discovered during the Method 21 survey but no later than 15 days of such a discovery. In addition, all repairs must be re-surveyed immediately after repair using OGI or Method 21 to ensure the fugitive emissions are no longer visible or is below a leak repair threshold of the plan. For our analysis, we evaluated three potential repair thresholds for Method 21 plans; 500 ppm, 2,500 ppm and 10,000 ppm. Therefore, options to reduce emissions under this option would vary based on the frequency of the monitoring/repair of the components as well as the repair threshold of the plan.

5.4.3.2 Emission Reduction Potential

In our analysis, we estimated emissions reductions for annual, semiannual and quarterly options for conducting the Method 21 monitoring at the three repair threshold levels of 500 ppm, 2,500 ppm and 10,000 ppm. The EPA Equipment Leaks Protocol document provides emissions factor data based on leak definition and monitoring frequencies primarily for the Synthetic Organic Chemical Manufacturing Industry (SOCMI) and Petroleum Refining Industry. This data was used to estimate the uncontrolled emissions (i.e., baseline emissions0 and the corresponding emission reduction percentages that could potentially be achieved for each of the leak definitions (500 ppm, 2,500 ppm, 10,000 ppm) and monitoring frequencies (annual, semiannual, quarterly). Using this information we calculated an expected emissions reduction percentage for each of the combinations of monitoring frequency and repair threshold. Table 5-20 summarizes calculated percent of expected reduction for each of the combinations.

Table 5-20. Percent Reduction in Emissions for EPA Method 21 Monitoring and Repair Plan Options

Monitoring Frequency	Repair Threshold		
	10,000 ppm	2,500 ppm	500 ppm
Annual	82	94	98
Semiannual	72	92	97
Quarterly	67	89	94

Based on these reduction percentages we calculated the estimated nationwide baseline emissions for the various options for a Method 21 monitoring and repair plan. Table 5-21 summarizes the estimated nationwide baseline emission reductions Method 21 monitoring repair plans.

Table 5-21. Nationwide Emission Reductions for EPA Method 21 Monitoring and Repair Plan Options for 2020 and 2025

Oil and Gas Segment	Number of New Facilities	Annual Monitoring (tpy)[a]		Semiannual Monitoring (tpy)[a]		Quarterly Monitoring (tpy)[a]	
		CH_4	VOC	CH_4	VOC	CH_4	VOC
Base Year 2012							
10,000 ppm							
Natural Gas Well Sites	3,346	33,872	9,415	29,741	8,267	27,676	7,693
Oil Well Sites	16,142	15,154	4,212	18,503	5,143	17,218	4,786
Gathering & Boosting Stations	259	7,464	2,075	6,553	1,822	6,098	1,695
Transmission Stations	6	307	8	269	7	251	7
Storage Stations	15	2,022	56	1,776	49	1,652	46
2,500 ppm							
Natural Gas Well Sites	3,346	38,828	2,856	38,002	2,795	36,763	2,704
Oil Well Sites	16,142	17,371	426	17,002	417	16,447	403
Gathering & Boosting Stations	259	8,556	2,378	8,374	2,328	8,101	2,252
Transmission Stations	6	352	10	344	10	333	9
Storage Stations	15	2,318	64	2,269	63	2,195	61

Oil and Gas Segment	Number of New Facilities	Annual Monitoring (tpy)[a]		Semiannual Monitoring (tpy)[a]		Quarterly Monitoring (tpy)[a]	
		CH_4	VOC	CH_4	VOC	CH_4	VOC
500 ppm							
Natural Gas Well Sites	3,346	40,481	2,977	40,068	2,947	38,828	2,856
Oil Well Sites	16,142	18,110	444	17,926	439	17,371	426
Gathering & Boosting Stations	259	8,920	2,480	8,829	2,454	8,556	2,378
Transmission Stations	6	367	10	363	10	352	10
Storage Stations	15	2,417	67	2,392	66	2,318	64
Projected Year 2020							
10,000 ppm							
Natural Gas Well Sites	5,518	20,539	5,709	18,034	5,013	16,782	4,665
Oil Well Sites	16,562	14,769	4,106	12,968	3,605	12,068	3,354
Gathering & Boosting Stations	259	7,464	2,075	6,553	1,822	6,098	1,695
Transmission Stations	6	307	8	269	7	251	7
Storage Stations	15	2,022	56	1,776	49	1,652	46
2,500 ppm							
Natural Gas Well Sites	5,518	23,545	6,565	23,044	6,406	22,292	6,197
Oil Well Sites	16,562	16,931	4,706	16,570	4,606	16,030	4,456
Gathering & Boosting Stations	259	8,556	2,378	8,374	2,328	8,101	2,252
Transmission Stations	6	352	10	344	10	333	9
Storage Stations	15	2,318	64	2,269	63	2,195	61
500 ppm							
Natural Gas Well Sites	5,518	24,547	6,823	24,296	6,754	23,545	6,545
Oil Well Sites	16,562	17,651	4,907	17,471	4,857	16,931	4,706
Gathering & Boosting Stations	259	8,920	2,480	8,829	2,454	8,556	2,378
Transmission Stations	6	367	10	363	10	352	10
Storage Stations	15	2,417	67	2,392	66	2,318	64

Oil and Gas Segment	Number of New Facilities	Annual Monitoring (tpy)[a]		Semiannual Monitoring (tpy)[a]		Quarterly Monitoring (tpy)[a]	
		CH_4	VOC	CH_4	VOC	CH_4	VOC
Projected Year 2025							
10,000 ppm							
Natural Gas Well Sites	38,933	144,916	40,283	127,243	35,370	118,407	32,914
Oil Well Sites	100,175	89,332	24,832	78,438	21,804	72,991	20,290
Gathering & Boosting Stations	1,554	44,781	12,448	39,320	10,930	36,590	10,171
Transmission Stations	36	1,841	51	1,617	45	1,504	42
Storage Stations	90	12,134	336	10,654	295	9,914	274
2,500 ppm							
Natural Gas Well Sites	38,933	166,123	46,178	162,588	45,195	157,286	43,722
Oil Well Sites	100,175	102,405	28,466	100,226	28,860	96,958	26,952
Gathering & Boosting Stations	1,554	51,335	14,270	50,243	13,966	48,604	13,511
Transmission Stations	36	2,111	58	2,066	57	1,998	55
Storage Stations	90	13,910	385	13,614	377	13,170	364
500 ppm							
Natural Gas Well Sites	38,933	173,192	48,143	171,424	47,652	166,123	46,178
Oil Well Sites	100,175	106,763	29,677	105,673	29,375	102,405	28,466
Gathering & Boosting Stations	1,554	53,519	14,877	52,973	14,725	51,335	14,270
Transmission Stations	36	2,200	61	2,178	60	2,111	58
Storage Stations	90	14,502	401	14,354	397	13,910	385

a. Assumes percent reduction as shown in Table 5-17.

5.4.2.3 Cost Impacts

Costs for preparing and implementing a fugitive emission monitoring plan were estimated using hourly estimates for each of the plan elements. The costs are based on the following assumptions:

- Labor cost for each of the monitoring plan elements 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 $231.20
- 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 16 hours to complete at a cost of $1,849.
- Notification of compliance status was estimated to take 1 person 1 hour to complete at a cost of $58 for gathering and boosting stations, transmission stations, and storage facilities. For companies that own and operate production well sites, the cost for notification of compliance status was estimated to be $58 for 22 well sites for a total of $1,272 per company.
- Cost for a Method 21 monitoring device ($10,800) and data collection system ($14,500).[56]
- Subsequent activities planning are estimated to take 2 people a total of 12 hours to complete at a cost of $1,387. For oil and natural gas production well sites, this cost was divided among the total number of well sites owned by a company, which was assumed to be 22. The cost per well site was estimated to be $63.

Costs for implementing a fugitive emission monitoring plan on a company level were estimated for each of the monitoring and repair elements. The costs are based on the following assumptions:

- The cost for Method 21 monitoring was estimated to be $462, assuming 2 people and 4 hours per person to survey a well production site using a M21 monitoring device, and $925, assuming 2 people and 8 hours per person to survey a gathering and boosting, transmission, and storage facility using a M21 monitoring device.
- Repair costs were estimated to be $2,999 at a leak definition of 10,000 ppm, $5,067 at a leak definition of 2,500 ppm and $5,400 at a leak definition of 500 ppm for production well sites. For compressor stations (i.e., gathering and boosting, transmission, storage), repair costs were estimated to be $29,288 at a leak definition of 10,000 ppm, $47,821 at a leak definition of 2,500 ppm and $52,900 at a leak definition of 500 ppm. These costs are based on leak percentages of 7.49 percent at a leak definition of 10,000 ppm, 12.25 percent at a leak definition of 2,500 ppm and 13.53 percent at a leak definition of 500 ppm. The leak percentages were calculated using the baseline SOCMI emission rate (0.00597 kg/hr/source) and the average leak rate to fraction leaking equations for 500, 2,500 and 10,000 ppmv leak definition in Table 5-4 of the EPA Protocol for Equipment Leak Emission Estimates. No data was available that included monitoring frequency, therefore it was assumed that the leak percentage represented the total annual leaks found using Method 21.

[56] 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.

- Cost for resurvey of components after repair based on \$2.00 per component resurveyed.
- 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 production well sites was calculated by summing up the costs for reading the rule, development of fugitive emissions monitoring plan, initial activities planning, and notification of initial compliance status. The total capital cost of these activities was calculated to be \$32,120 per company. Assuming that each company owns and operates 22 well sites, the capital cost per well site was estimated to be \$1,460. For gathering and boosting, transmission, and storage facilities the capital cost for reading the rule, development of fugitive emissions monitoring plan, initial activities planning, and notification of initial compliance status was calculated to be \$30,907 per facility.

For all segments, the annual cost includes; subsequent activities planning, Method 21 survey, cost of repair of fugitive emissions found, resurvey of the repaired components, preparation and submittal of an annual report, and the amortized capital cost over 8 years at 7 percent interest. For our analysis we calculated the annual cost for annual, semiannual and quarterly Method 21 surveys using the three repair thresholds. Tables 5-22, 5-23 and 5-24 summarizes the capital and annual cost for each segment at each of the three survey frequencies and three repair thresholds. Tables A-1 through A-6 in Appendix A provide the detailed calculations of the annual cost for the Method 21 monitoring and repair program under the nine sub-option combinations of monitoring frequency and repair threshold.

The cost per ton of emissions reduced was calculated using two separate methods. The first method attributes all of the costs to each pollutant separately (the single-pollutant method) using representative unit costs for each control option. The second method allocates the annual cost among the pollutants (multi-pollutant method) that a given technology reduced (i.e., CH_4 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 CH_4 and VOC are equal; and therefore the allocation of the annual cost was divided equally and applied to the CH_4 and VOC reductions.

Based on estimated emissions reductions and the estimated cost for implementing a Method 21 fugitive emissions monitoring and repair program at the affected facilities, we calculated a cost of control for CH_4 and VOC for the various sub-options for oil and natural gas production well sites, gathering and boosting stations, transmission stations and storage facilities. We also calculated the weighted average cost of control for all well sites and all compressor stations under each of the monitoring and repair plan sub options. Tables 5-22, 5-23 and 5-24 present a summary of capital and annual costs and the cost of control for CH_4 and VOC for the Method 21 plan monitoring options (i.e., annual, semiannual and quarterly, respectively) and the three repair thresholds (i.e., 10,000 ppm, 2,500 ppm and 500 ppm, respectively) based on 100 percent of the cost being attributed to the individual pollutants. Tables 5-23, 5-24 and 5-25 present a summary of the capital and annual costs, and the cost of control for CH_4 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). See Tables A-11 through A-32 in Appendix A for detail on the calculations of emissions, reductions and the cost of control analysis for the various sub-options for each segment.

5.4.2.4 Secondary Impacts

No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of fugitive emissions from leaks. There are some emissions that would be generated by the Method 21 monitoring with the exception of employee or contractors driving to and from the site for the fugitive emissions survey, however, these emissions cannot be quantified because there is no data related to the distance that would need to be traveled to the site. However, it is believed that the secondary impacts expected from the implementation of a Method 21 monitoring and repair program would be minimal.

Table 5-22. Summary of the Model Plant Cost of Control for the Annual Method 21 Monitoring and Repair Plan Options Single-Pollutant

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
10,000 ppm									
Natural Gas Production Well Site[d]	3.72	1.03	$1,460	$4,020	$3,157	$1,080	$3,885	$848	$3,051
Oil Production Well Site[d]	0.73	0.20	$1,460	$4,020	$3,813	$5,517	$19,847	$5,233	$18,826
Well Site Program Weighted Average[h]						$4,408	$15,858	$4,137	$14,884
Gathering and Boosting Station[e]	28.8	8.01	$30,907	$37,203	$30,523	$1,291	$4,644	$1,059	$3,810
Transmission Station[e]	51.1	1.42	$30,907	$37,203	$37,203	$727	$26,284	$727	$26,284
Storage Facility[e]	134.8	3.73	$30,907	$37,203	$37,203	$276	$9,971	$276	$9,971
Compressor Station Weighted Average						$1,225	$5,393	$1,010	$4,622
2,500 ppm									
Natural Gas Production Well Site[d]	4.27	1.19	$1,460	$6,103	$5,113	$1,430	$5,145	$1,198	$4,311
Oil Production Well Site[d]	1.02	0.28	$1,460	$6,103	$5,866	$5,970	$21,475	$5,738	$20,642
Well Site Program Weighted Average[h]						$4,835	$17,394	$4,603	$16,560
Gathering and Boosting Station[e]	33.0	9.18	$30,907	$55,860	$48,203	$1,691	$6,083	$1,459	$5,249
Transmission Station[e]	58.6	1.62	$30,907	$55,860	$55,860	$953	$34,427	$953	$34,427
Storage Facility[e]	154.6	4.28	$30,907	$55,860	$55,860	$361	$13,060	$361	$13,060
Compressor Station Weighted Average						$1,604	$7,064	$1,390	$6,293

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
500 ppm									
Natural Gas Production Well Site[d]	4.45	1.24	$1,460	$6,437	$5,406	$1,447	$5,206	$1,215	$4,372
Oil Production Well Site[d]	1.07	0.30	$1,460	$6,437	$6,190	$6,040	$21,728	$5,808	$20,894
Well Site Program Weighted Average[h]						$4,892	$17,599	$4,660	$16,765
Gathering and Boosting Station[e]	34.4	9.57	$30,907	$60,973	$52,990	$1,770	$6,369	$1,539	$5,535
Transmission Station[e]	61.1	1.69	$30,907	$60,973	$60,973	$998	$36,045	$998	$36,045
Storage Facility[e]	161.1	4.46	$30,907	$60,973	$60,973	$378	$13,673	$378	$13,673
Compressor Station Weighted Average						$1,679	$7,396	$1,465	$6,625

a. Assumes 82% reduction with the implementation of repair threshold of 10,000 ppm, 94% reduction for 2,500 ppm and 98% for 500 ppm for an annual method 21 monitoring.
b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of $31,120 divided between an average of 22 well sites per company. The capital cost for the gathering and boosting, transmission and storage segments includes the cost of implementing the monitoring program of $30,907.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based CH_4 reductions, CH_4 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 $3,775 for 10,000 ppm repair threshold, $5,858 for 2,500 ppm and $6,193 for 500 ppm and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for compressor stations (i.e., gathering and boosting, transmission and storage) includes annual monitoring and repair cost of 32,027 for 10,000 ppm repair threshold, $50,685 for 2,500 ppm and $55,973 for 500 ppm and amortization of the capital cost over 8 years at 7% interest.
Note: Transmission and storage facilities do not own the natural gas; therefore cost benefits from reducing the amount of natural gas as the result of equipment leaks was not estimated for the transmission or storage segment.

Table 5-23. Summary of the Model Plant Cost of Control for the Semiannual Method 21 Monitoring and Repair Plan Options Single-Pollutant

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
10,000 ppm									
Natural Gas Production Well Site[d]	3.27	0.91	$1,460	$4,482	$3,725	$1,371	$4,934	$1,140	$4,100
Oil Production Well Site[d]	0.78	0.22	$1,460	$4,482	$4,301	$5,724	$20,593	$5,493	$19,759
Well Site Program Weighted Average[h]						$4,637	$16,680	$4,405	$15,846
Gathering and Boosting Station[e]	25.3	7.03	$30,907	$38,128	$32,263	$1,507	$5,421	$1,275	$4,587
Transmission Station[e]	44.9	1.24	$30,907	$38,128	$38,128	$849	$30,679	$849	$30,679
Storage Facility[e]	118.4	3.28	$30,907	$38,128	$38,128	$322	$11,638	$322	$11,638
Compressor Station Weighted Average						$1,429	$6,295	$1,215	$5,524
2,500 ppm									
Natural Gas Production Well Site[d]	4.18	1.16	$1,460	$6,565	$5,597	$1,572	$5,655	$1,340	$4,821
Oil Production Well Site[d]	1.00	0.28	$1,460	$6,565	$6,333	$6,562	$23,605	$6,330	$22,771
Well Site Program Weighted Average[h]						$5,315	$19,119	$5,083	$18,285
Gathering and Boosting Station[e]	32.3	8.99	$30,907	$56,785	$49,291	$1,756	$6,318	$1,525	$5,485
Transmission Station[e]	57.4	1.59	$30,907	$56,785	$56,785	$990	$35,758	$990	$35,758
Storage Facility[e]	151.3	4.19	$30,907	$56,785	$56,785	$375	$13,565	$375	$13,565
Compressor Station Weighted Average						$1,666	$7,337	$1,452	$6,566
500 ppm									

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]	4.40	1.22	$1,460	$6,899	$5,879	$1,567	$5,637	$1,335	$4,803
Oil Production Well Site[d]	1.05	0.29	$1,460	$6,899	$6,655	$6,540	$23,529	$6,309	$22,695
Well Site Program Weighted Average[h]						$5,298	$19,058	$5,066	$18,224
Gathering and Boosting Station[e]	34.1	9.48	$30,907	$61,898	$53,996	$1,816	$6,532	$1,584	$5,698
Transmission Station[e]	60.5	1.67	$30,907	$61,898	$61,898	$1,023	$36,969	$1,023	$36,969
Storage Facility[e]	159.5	4.41	$30,907	$61,898	$61,898	$388	$14,024	$388	$14,024
Compressor Station Weighted Average						$1,722	$7,586	$1,508	$6,814

a. Assumes 72% reduction with the implementation of repair threshold of 10,000 ppm, 92% reduction for 2,500 ppm and 97% for 500 ppm for an annual method 21 monitoring.
b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of $31,120 divided between an average of 22 well sites per company. The capital cost for the gathering and boosting, transmission and storage segments includes the cost of implementing the monitoring program of $30,907.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based CH_4 reductions, CH_4 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 $4,238 for 10,000 ppm repair threshold, $6,320 for 2,500 ppm and $6,655 for 500 ppm and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for compressor stations (i.e., gathering and boosting, transmission and storage) includes annual monitoring and repair cost of $32,952 for 10,000 ppm repair threshold, $51,609 for 2,500 ppm and $61,8988 for 500 ppm and amortization of the capital cost over 8 years at 7% interest.
Note: Transmission and storage facilities do not own the natural gas; therefore cost benefits from reducing the amount of natural gas as the result of equipment leaks was not estimated for the transmission or storage segment.

Table 5-24. Summary of the Model Plant Cost of Control for the Quarterly Method 21 Monitoring and Repair Plan Options Single-Pollutant

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
10,000 ppm									
Natural Gas Production Well Site[d]	3.04	0.85	$1,460	$5,407	$4,702	$1,778	$6,396	$1,546	$5,562
Oil Production Well Site[d]	0.36	0.20	$1,460	$5,407	$5,238	$15,066	$26,696	$14,596	$25,862
Well Site Program Weighted Average[h]						$11,746	$21,623	$11,335	$20,789
Gathering and Boosting Station	23.5	6.55	$30,907	$39,978	$34,519	$1,698	$6,108	$1,466	$5,274
Transmission Station	41.8	1.16	$30,907	$39,978	$39,978	$957	$34,568	$957	$34,568
Storage Facility	110.2	3.05	$30,907	$39,978	$39,978	$363	$13,113	$363	$13,113
Compressor Station Weighted Average						$1,610	$7,093	$1,396	$6,322
2,500 ppm									
Natural Gas Production Well Site[d]	4.04	1.12	$1,460	$7,490	$6,553	$1,854	$6,669	$1,622	$5,835
Oil Production Well Site[d]	0.97	0.27	$1,460	$7,490	$7,265	$7,738	$27,838	$7,506	$27,004
Well Site Program Weighted Average[h]						$6,268	$22,548	$6,036	$21,714
Gathering and Boosting Station	31.3	8.69	$30,907	$58,635	$51,385	$1,875	$6,744	$1,643	$5,910
Transmission Station	55.5	1.54	$30,907	$58,635	$58,635	$1,056	$38,168	$1,056	$38,168
Storage Facility	146.3	4.05	$30,907	$58,635	$58,635	$401	$14,479	$401	$14,479
Compressor Station Weighted Average						$1,778	$7,832	$1,564	$7,060
500 ppm									

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]	4.27	1.19	$1,460	$7,824	$6,835	$1,834	$6,597	$1,602	$5,763
Oil Production Well Site[d]	1.02	0.28	$1,460	$7,824	$7,587	$7,654	$27,534	$7,422	$26,700
Well Site Program Weighted Average[h]						$6,199	$22,302	$5,968	$21,468
Gathering and Boosting Station	33.0	9.18	$30,907	$63,747	$56,090	$1,930	$6,942	$1,698	$6,108
Transmission Station	58.6	1.62	$30,907	$63,747	$63,747	$1,087	$39,288	$1,087	$39,288
Storage Facility	154.6	4.28	$30,907	$63,747	$63,747	$412	$14,904	$412	$14,904
Compressor Station Weighted Average						$1,830	$8,062	$1,616	$7,290

a. Assumes 67% reduction with the implementation of repair threshold of 10,000 ppm, 89% reduction for 2,500 ppm and 94% for 500 ppm for an annual method 21 monitoring.
b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of $31,120 divided between an average of 22 well sites per company. The capital cost for the gathering and boosting, transmission and storage segments includes the cost of implementing the monitoring program of $30,907.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based CH_4 reductions, CH_4 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 $5,163 for 10,000 ppm repair threshold, $7,245 for 2,500 ppm and $7,580 for 500 ppm and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for compressor stations (i.e., gathering and boosting, transmission and storage) includes annual monitoring and repair cost of $34,802 for 10,000 ppm repair threshold, $53,459 for 2,500 ppm and $63,747 for 500 ppm and amortization of the capital cost over 8 years at 7% interest.
Note: Transmission and storage facilities do not own the natural gas; therefore cost benefits from reducing the amount of natural gas as the result of equipment leaks was not estimated for the transmission or storage segment.

Table 5-25. Summary of the Model Plant Cost of Control for the Annual Method 21 Monitoring and Repair Plan Options Multi-Pollutant

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
10,000 ppm									
Natural Gas Production Well Site[d]	3.72	1.03	$1,460	$4,020	$3,157	$540	$1,943	$424	$1,526
Oil Production Well Site[d]	0.73	0.20	$1,460	$4,020	$3,813	$2,758	$9,924	$2,617	$9,413
Well Site Program Weighted Average[h]						$2,204	$7,929	$2,069	$7,442
Gathering and Boosting Station	28.8	8.01	$30,907	$37,203	$30,523	$646	$2,322	$530	$1,905
Transmission Station	51.1	1.42	$30,907	$37,203	$37,203	$364	$13,142	$364	$13,142
Storage Facility	134.8	3.73	$30,907	$37,203	$37,203	$138	$4,985	$138	$4,985
Compressor Station Weighted Average						$612	$2,697	$505	$2,311
2,500 ppm									
Natural Gas Production Well Site[d]	4.27	1.19	$1,460	$6,103	$5,113	$715	$2,573	$599	$2,156
Oil Production Well Site[d]	1.02	0.28	$1,460	$6,103	$5,866	$2,985	$10,738	$2,869	$10,321
Well Site Program Weighted Average[h]						$2,418	$8,697	$2,302	$8,280
Gathering and Boosting Station	33.0	9.18	$30,907	$55,860	$48,203	$845	$3,042	$730	$2,625
Transmission Station	58.6	1.62	$30,907	$55,860	$55,860	$476	$17,214	$476	$17,214
Storage Facility	154.6	4.28	$30,907	$55,860	$55,860	$181	$6,530	$181	$6,530
Compressor Station Weighted Average						$802	$3,532	$695	$3,147

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
500 ppm									
Natural Gas Production Well Site[d]	4.45	1.24	$1,460	$6,437	$5,406	$724	$2,603	$608	$2,186
Oil Production Well Site[d]	1.07	0.30	$1,460	$6,437	$6,190	$3,020	$10,864	$2,904	$10,447
Well Site Program Weighted Average[h]						$2,446	$8,799	$2,330	$8,383
Gathering and Boosting Station	34.4	9.57	$30,907	$60,973	$52,990	$885	$3,185	$769	$2,768
Transmission Station	61.1	1.69	$30,907	$60,973	$60,973	$499	$18,022	$499	$18,022
Storage Facility	161.1	4.46	$30,907	$60,973	$60,973	$189	$6,837	$189	$6,837
Compressor Station Weighted Average						$840	$3,698	$732	$3,312

a. Assumes 82% reduction with the implementation of repair threshold of 10,000 ppm, 94% reduction for 2,500 ppm and 98% for 500 ppm for an annual method 21 monitoring.
b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of $31,120 divided between an average of 22 well sites per company. The capital cost for the gathering and boosting, transmission and storage segments includes the cost of implementing the monitoring program of $30,907.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based CH_4 reductions, CH_4 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 $3,775 for 10,000 ppm repair threshold, $5,858 for 2,500 ppm and $6,193 for 500 ppm and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for compressor stations (i.e., gathering and boosting, transmission and storage) includes annual monitoring and repair cost of 32,027 for 10,000 ppm repair threshold, $50,685 for 2,500 ppm and $55,973 for 500 ppm and amortization of the capital cost over 8 years at 7% interest.
Note: Transmission and storage facilities do not own the natural gas; therefore cost benefits from reducing the amount of natural gas as the result of equipment leaks was not estimated for the transmission or storage segment.
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Table 5-26. Summary of the Model Plant Cost of Control for the Semiannual Method 21 Monitoring and Repair Plan Options Multi-Pollutant

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
10,000 ppm									
Natural Gas Production Well Site[d]	3.27	0.91	$1,460	$4,482	$3,725	$686	$2,467	$570	$2,050
Oil Production Well Site[d]	0.78	0.22	$1,460	$4,482	$4,301	$2,862	$10,297	$2,746	$9,880
Well Site Program Weighted Average[h]						$2,318	$8,340	$2,202	$7,923
Gathering and Boosting Station	25.3	7.03	$30,907	$38,128	$32,263	$753	$2,710	$638	$2,293
Transmission Station	44.9	1.24	$30,907	$38,128	$38,128	$425	$15,339	$425	$15,339
Storage Facility	118.4	3.28	$30,907	$38,128	$38,128	$161	$5,819	$161	$5,819
Compressor Station Weighted Average						$715	$3,148	$607	$2,762
2,500 ppm									
Natural Gas Production Well Site[d]	4.18	1.16	$1,460	$6,565	$5,597	$786	$2,828	$670	$2,411
Oil Production Well Site[d]	1.00	0.28	$1,460	$6,565	$6,333	$3,281	$11,802	$3,165	$11,385
Well Site Program Weighted Average[h]						$2,657	$9,560	$2,541	$9,143
Gathering and Boosting Station	32.3	8.99	$30,907	$56,785	$49,291	$878	$3,159	$762	$2,742
Transmission Station	57.4	1.59	$30,907	$56,785	$56,785	$495	$17,879	$495	$17,879
Storage Facility	151.3	4.19	$30,907	$56,785	$56,785	$188	$6,782	$188	$6,782
Compressor Station Weighted Average						$833	$3,669	$726	$3,283

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
500 ppm									
Natural Gas Production Well Site[d]	4.40	1.22	$1,460	$6,899	$5,879	$783	$2,819	$668	$2,402
Oil Production Well Site[d]	1.05	0.29	$1,460	$6,899	$6,655	$3,270	$11,764	$3,154	$11,348
Well Site Program Weighted Average[h]						$2,649	$9,529	$2,533	$9,112
Gathering and Boosting Station	34.1	9.48	$30,907	$61,898	$53,996	$908	$3,266	$792	$2,849
Transmission Station	60.5	1.67	$30,907	$61,898	$61,898	$512	$18,484	$512	$18,484
Storage Facility	159.5	4.41	$30,907	$61,898	$61,898	$194	$7,012	$194	$7,012
Compressor Station Weighted Average						$861	$3,793	$754	$3,407

a. Assumes 72% reduction with the implementation of repair threshold of 10,000 ppm, 92% reduction for 2,500 ppm and 97% for 500 ppm for an annual method 21 monitoring.
b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of $31,120 divided between an average of 22 well sites per company. The capital cost for the gathering and boosting, transmission and storage segments includes the cost of implementing the monitoring program of $30,907.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based CH_4 reductions, CH_4 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 $4,238 for 10,000 ppm repair threshold, $6,320 for 2,500 ppm and $6,655 for 500 ppm and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for compressor stations (i.e., gathering and boosting, transmission and storage) includes annual monitoring and repair cost of $32,952 for 10,000 ppm repair threshold, $51,609 for 2,500 ppm and $61,8988 for 500 ppm and amortization of the capital cost over 8 years at 7% interest.
Note: Transmission and storage facilities do not own the natural gas; therefore cost benefits from reducing the amount of natural gas as the result of equipment leaks was not estimated for the transmission or storage segment.

Table 5-27. Summary of the Model Plant Cost of Control for the Quarterly Method 21 Monitoring and Repair Plan Options Multi-Pollutant

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
10,000 ppm									
Natural Gas Production Well Site[d]	3.04	0.85	$1,460	$5,407	$4,702	$889	$3,198	$773	$2,781
Oil Production Well Site[d]	0.36	0.20	$1,460	$5,407	$5,238	$7,533	$13,348	$7,298	$12,931
Well Site Program Weighted Average[h]						$5,873	$10,811	$5,667	$10,394
Gathering and Boosting Station	23.5	6.55	$30,907	$39,978	$34,519	$849	$3,054	$733	$2,637
Transmission Station	41.8	1.16	$30,907	$39,978	$39,978	$478	$17,284	$478	$17,284
Storage Facility	110.2	3.05	$30,907	$39,978	$39,978	$181	$6,557	$181	$6,557
Compressor Station Weighted Average						$805	$3,547	$698	$3,161
2,500 ppm									
Natural Gas Production Well Site[d]	4.04	1.12	$1,460	$7,490	$6,553	$927	$3,335	$811	$2,918
Oil Production Well Site[d]	0.97	0.27	$1,460	$7,490	$7,265	$3,869	$13,919	$3,753	$13,502
Well Site Program Weighted Average[h]						$3,134	$11,274	$3,018	$10,857
Gathering and Boosting Station	31.3	8.69	$30,907	$58,635	$51,385	$937	$3,372	$821	$2,955
Transmission Station	55.5	1.54	$30,907	$58,635	$58,635	$528	$19,084	$528	$19,084
Storage Facility	146.3	4.05	$30,907	$58,635	$58,635	$200	$7,239	$200	$7,239
Compressor Station Weighted Average						$889	$3,916	$782	$3,530

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
500 ppm									
Natural Gas Production Well Site[d]	4.27	1.19	$1,460	$7,824	$6,835	$917	$3,298	$801	$2,881
Oil Production Well Site[d]	1.02	0.28	$1,460	$7,824	$7,587	$3,827	$13,767	$3,711	$13,350
Well Site Program Weighted Average[h]						$3,100	$11,151	$2,984	$10,734
Gathering and Boosting Station	33.0	9.18	$30,907	$63,747	$56,090	$965	$3,471	$849	$3,054
Transmission Station	58.6	1.62	$30,907	$63,747	$63,747	$544	$19,644	$544	$19,644
Storage Facility	154.6	4.28	$30,907	$63,747	$63,747	$206	$7,452	$206	$7,452
Compressor Station Weighted Average						$915	$4,031	$808	$3,645

a. Assumes 67% reduction with the implementation of repair threshold of 10,000 ppm, 89% reduction for 2,500 ppm and 94% for 500 ppm for an annual method 21 monitoring.
b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of $31,120 divided between an average of 22 well sites per company. The capital cost for the gathering and boosting, transmission and storage segments includes the cost of implementing the monitoring program of $30,907.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based CH_4 reductions, CH_4 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 $5,163 for 10,000 ppm repair threshold, $7,245 for 2,500 ppm and $7,580 for 500 ppm and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for compressor stations (i.e., gathering and boosting, transmission and storage) includes annual monitoring and repair cost of $34,802 for 10,000 ppm repair threshold, $53,459 for 2,500 ppm and $63,747 for 500 ppm and amortization of the capital cost over 8 years at 7% interest.
Note: Transmission and storage facilities do not own the natural gas; therefore cost benefits from reducing the amount of natural gas as the result of equipment leaks was not estimated for the transmission or storage segment.

5.5 Regulatory Options

Monitoring and repair of fugitive emissions components using OGI or Method 21 is believed to be the most viable methods for reducing fugitive emissions. Therefore, the following regulatory options were considered for reducing fugitive emissions from oil and natural gas production well sites, gathering and boosting stations, transmission stations, and storage facilities:

- Regulatory Option 1. Require the implementation of a fugitive emissions monitoring and repair program using OGI. The sub-options that we evaluated for a fugitive emissions monitoring and repair program using OGI are based on three monitoring frequencies; annual, semiannual and quarterly) as shown below.
    - Regulatory Option 1a - Conducting monitoring and repair on an annual frequency.
    - Regulatory Option 1b - Conducting monitoring and repair on a semiannual frequency.
    - Regulatory Option 1c - Conducting monitoring and repair on a quarterly frequency.
- Regulatory Option 2. Require the implementation of a monitoring and repair program using Method 21. The sub-options for a fugitive emissions monitoring and repair program using Method 21 are based on the combination of three monitoring frequencies (annual, semiannual and quarterly) and three leak repair thresholds (10,000 ppm, 2,500 ppm and 500 ppm). The sub-options shown below summarize those possible combinations.
    - Regulatory Option 2a -500 - Conducting monitoring and repair on an annual frequency with a repair threshold level of 500 ppm.
    - Regulatory Option 2a -2500 - Conducting Method 21 monitoring and repair on an annual frequency with a repair threshold level of 2,500 ppm.
    - Regulatory Option 2a -10,000 - Conducting Method 21 monitoring and repair on an annual frequency with a repair threshold level of 10,000 ppm.
    - Regulatory Option 2b -500 - Conducting Method 21 monitoring and repair on a semiannual frequency with a repair threshold level of 500 ppm.
    - Regulatory Option 2b -2500 - Conducting Method 21 monitoring and repair on a semiannual frequency with a repair threshold level of 2,500 ppm.
    - Regulatory Option 2b -10,000 - Conducting Method 21 monitoring and repair on a semiannual frequency with a repair threshold level of 10,000 ppm.
    - Regulatory Option 2c -500 - Conducting Method 21 monitoring and repair on a quarterly frequency with a repair threshold level of 500 ppm.

- Regulatory Option 2c -2500 - Conducting Method 21 monitoring and repair on a quarterly frequency with a repair threshold level of 2,500 ppm.
- Regulatory Option 2c -10,000 - Conducting Method 21 monitoring and repair on a quarterly frequency with a repair threshold level of 10,000 ppm.

5.5.1 Evaluation of Regulatory Options for Fugitive Emissions

5.5.1.1 Option 1 Based on OGI Monitoring

As noted above, we calculated a weighted average cost of control for well sites (which includes oil and gas production well sites) and compressor stations (which includes gathering and boosting stations, transmission stations and storage facilities). For ease of review we have summarized the cost of control for the sub-options for Option 1 for well sites and compressor stations in Table 5-28.

Well Sites

For well sites, we have three sub-options based on the frequency of OGI monitoring conducted. For Option 1a, based on an annual frequency, the single-pollutant cost of control, without considering savings for gas recovery was calculated to be $2,475 per ton of CH_4 and $8,903 per ton of VOC. The multi-pollutant cost of control, without considering savings for gas recovery was calculated to be $1,237 per ton of CH_4 and $4,451 per ton of VOC. Option 1b based on a semiannual frequency, the single-pollutant cost of control, without considering savings for gas recovery was calculated to be $2,768 per ton of CH_4 and $9,958 per ton of VOC. The multi-pollutant cost of control, without considering savings for gas recovery was calculated to be $1,384 per ton of CH_4 and $4,979 per ton of VOC. Option 1c, based on a quarterly frequency, the single-pollutant cost of control, without considering savings for gas recovery was calculated to be $3,753 per ton of CH_4 and $13,502 per ton of VOC. The multi-pollutant cost of control, without considering savings for gas recovery was calculated to be $1,877 per ton of CH_4 and $6,751 per ton of VOC.

If we consider gas savings, the cost are reduced based on the gas considered to have not been lost. For Option 1a, based on an annual frequency, the single-pollutant cost of control, considering savings for gas recovery was calculated to be $2,243 per ton of CH_4 and $8,069 per ton of VOC. The multi-pollutant cost of control, considering savings for gas recovery was calculated to be $1,121 per ton of CH_4 and $4,035 per ton of VOC. Option 1b, based on a semiannual frequency, the single-pollutant cost of control, without considering savings for gas recovery was calculated to be $2,536 per ton of CH_4 and $9,124 per ton of VOC. The multi-pollutant cost of control, considering savings for gas recovery was calculated to be $1,268 per ton of CH_4 and $4,562 per ton of VOC. Option 1c, based on a quarterly frequency, the single-pollutant cost of control, considering savings for gas recovery was calculated to be $3,521 per ton of CH_4 and $12,668 per ton of VOC. The multi-pollutant cost of control, considering savings for gas recovery was calculated to be $1,761 per ton of CH_4 and $6,334 per ton of VOC.

Compressor Stations

For compressor stations we have three sub-options based on the frequency of OGI monitoring conducted. Based on an annual frequency (option 1a), the single-pollutant cost of control, without consideration of savings for gas recovery, was calculated to be $686 per ton of CH_4 and $3,110 per ton of VOC. The multi-pollutant cost of control, without considering savings for gas recovery was calculated to be $343 per ton of CH_4 and $1,555 per ton of VOC. Based on a semiannual frequency (option 1b), the single-pollutant cost of control, without consideration of savings for gas recovery, was calculated to be $718 per ton of CH_4 and $3,281 per ton of VOC. The multi-pollutant cost of control, without considering savings for gas recovery was calculated to be $359 per ton of CH_4 and $1,641per ton of VOC. Based on a quarterly frequency (option 1c), the single-pollutant cost of control, without consideration of savings for gas recovery, was calculated to be $930 per ton of CH_4 and $4,273 per ton of VOC. The multi-pollutant cost of control, without considering savings for gas recovery was calculated to be $465 per ton of CH_4 and $2,136 per ton of VOC.

Because the gas handled by transmission and storage facilities is not typically owned by these facilities, we do not consider the value of the gas saved as an offset to the cost. However, for gathering and boosting stations, the gas savings could be considered. Therefore, we calculated the cost of control for compressor stations considering the gas savings contributed by gathering and bosting stations. Based on an annual frequency (option 1a), the single-pollutant cost of control, with consideration of savings for gas recovery, was calculated to be $471 per ton of CH_4 and $2,338 per ton of VOC. The multi-pollutant cost of control, considering savings for gas recovery was calculated to be $236 per ton of CH_4 and $1,169 per ton of VOC. Based on a semiannual frequency (option 1b), the single-pollutant cost of control, with consideration of savings for gas recovery, was calculated to be $504 per ton of CH_4 and $2,510 per ton of VOC. The multi-pollutant cost of control, considering savings for gas recovery was calculated to be $252 per ton of CH_4 and $1,255 per ton of VOC. And based on a quarterly frequency (option 1c), the single-pollutant cost of control, with consideration of savings for gas recovery, was calculated to be $715 per ton of CH_4 and $3,502 per ton of VOC. The multi-pollutant cost of control, considering savings for gas recovery was calculated to be $358 per ton of CH_4 and $1,751 per ton of VOC.

We also evaluated the reasonableness of the burden to industry for the three options with the respective reductions and costs. We determined that the quarterly monitoring frequency was too costly for most segments and would be considered overly burdensome given the additional level of emissions reductions. Annual and semiannual monitoring appeared to have reasonable associated costs. Therefore, our analysis of nationwide impacts considered options 1a (annual monitoring) and 1b (semiannual monitoring) as OGI monitoring and repair plan options for the NSPS.

Table 5-28. Summary of the Cost of Control for Sub Options of Option 1 Based on OGI Monitoring

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								
1a - Annual	$2,475	$8,903	$1,237	$4,451	$2,243	$8,069	$1,121	$4,035
1b - Semiannual	$2,768	$9,958	$1,384	$4,979	$2,536	$9,124	$1,268	$4,562
1c - Quarterly	$3,753	$13,502	$1,877	$6,751	$3,521	$12,668	$1,761	$6,334
Compressor Stations								
1a - Annual	$686	$3,110	$343	$1,555	$471	$2,338	$236	$1,169
1b - Semiannual	$718	$3,281	$359	$1,641	$504	$2,510	$252	$1,255
1c - Quarterly	$930	$4,273	$465	$2,136	$715	$3,502	$358	$1,751

5.5.1.2 Option 2 - Based on Method 21 Monitoring and Three Leak Repair Thresholds

As noted above, we calculated a weighted average cost of control for well sites (which includes oil and gas production well sites) and compressor stations (which includes gathering and boosting stations, transmission stations and storage facilities) for nine Method 21 monitoring and repair plan sub-options based on the combination of monitoring frequency (annual, semiannual and quarterly) and three potential repair thresholds (10,000 ppm, 2,500 ppm and 500 ppm). For ease of review we have summarized the cost of control for the sub-options for Option 4 for well sites and compressor stations in Table 5-29.

Our analysis of the cost of control for the various options, using both the single-pollutant and multi-pollutant cost approaches, indicates that these cost of control generally increases with increasing monitoring frequency (i.e., quarterly monitoring has a higher cost of control that annual monitoring) and increase with decreasing fugitive emissions repair threshold (i.e., 500 ppm results in a higher cost of control than 10,000 ppm).

Well Sites

For well sites, the cost of control under the single-pollutant method (i.e., all cost attributed to methane and VOC individually), and without considering gas savings, was determined to range from $4,408 (annual frequency at 10,000 ppm repair threshold) to $6,199 (quarterly frequency at 500 ppm repair threshold per ton of methane and $15,858 to $22,302 per ton of VOC. Under the multi-pollutant method, (i.e., 50 percent of the cost attributed to methane and 50 percent attributed to VOC), and without considering gas savings, was determined to be from $2,204 to $3,100 per ton of methane and $7,929 to $11,151 per ton of VOC.

If we consider gas savings, the cost are reduced based on the gas considered to have not been lost. When we consider gas savings, under the single-pollutant method, the cost of control was found to range from $4,137 to $ 5,968 per ton of methane and $14,884 to $21,468 per ton of VOC, and under the multi-pollutant method $2,069 to $2,984 per ton of methane and $7,442 to $10,734 per ton of VOC.

Compressor Stations

For compressor stations (which includes gathering and boosting, transmission and storage), the cost of control under the single-pollutant method (i.e., all cost attributed to methane and VOC individually), and without considering gas savings, was determined to range from $1,225 (annual frequency at 10,000 ppm repair threshold) to $1,830 (quarterly frequency at 500 ppm repair threshold per ton of methane and $5,393 to $8,062 per ton of VOC. Under the multi-pollutant method, (i.e., 50 percent of the cost attributed to methane and 50 percent attributed to VOC), and without considering gas savings, was determined to be from $612 to $915 per ton of methane and $2,697 to $4,031 per ton of VOC.

Because the gas handled by transmission and storage facilities is not typically owned by these facilities, we do not consider the value of the gas saved as an offset to the cost. However, for gathering and boosting stations, the gas savings could be considered. Therefore, we calculated the cost of control for compressor stations considering the gas savings contributed by gathering and boosting stations. If we consider gas savings, the cost are reduced based on the gas considered to have not been lost. For compressor stations, when we consider gas savings, under the single-pollutant method, the cost of control was found to range from $1,010 to $ 1,616 per ton of methane and $4,622 to $7,290 per ton of VOC, and under the multi-pollutant method $505 to $808 per ton of methane and $2,311 to $3,645 per ton of VOC.

As with OGI monitoring, we also evaluated the reasonableness of the burden to industry for the three options with the respective reductions and costs. We determined that the quarterly monitoring frequency was too costly for most segments and would be considered overly burdensome given the additional level of emissions reductions. In addition, we determined that the 500 ppm leak repair threshold was too costly for these segments and have eliminated this option from each of the monitoring frequencies. Annual and semiannual monitoring appeared to have reasonable associated costs. Therefore, our analysis of nationwide impacts considered the two sub-options for 2a (annual monitoring at the 10,000 and 2,500 ppm repair thresholds) and the two sub-options for option 2b (semiannual monitoring at the 10,000 and 2,500 ppm repair thresholds) as viable Method 21 monitoring and repair plan options for the NSPS.

Table 5-29. Summary of the Cost of Control for Sub Options of Option 2 Based on Method 21 Monitoring and Three Repair Thresholds

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								
2a - Annual, 10,000 ppm	$4,408	$15,858	$2,204	$7,929	$4,137	$14,884	$2,069	$7,442
2a - Annual, 2,500 ppm	$4,835	$17,394	$2,418	$8,697	$4,603	$16,560	$2,302	$8,280
2a - Annual, 500 ppm	$4,892	$17,599	$2,446	$8,799	$4,660	$16,765	$2,330	$8,383
2b - Semiannual, 10,000 ppm	$4,637	$16,680	$2,318	$8,340	$4,405	$15,846	$2,202	$7,923
2b - Semiannual, 2,500 ppm	$5,315	$19,119	$2,657	$9,560	$5,083	$18,285	$2,541	$9,143
2b - Semiannual, 500	$5,298	$19,058	$2,649	$9,529	$5,066	$18,224	$2,533	$9,112
2c - Quarterly, 10,000 ppm	$11,746	$21,623	$5,873	$10,811	$11,335	$20,789	$5,667	$10,394
2c - Quarterly, 2,500 ppm	$6,268	$22,548	$3,134	$11,274	$6,036	$21,714	$3,018	$10,857
2c - Quarterly, 500 ppm	$6,199	$22,302	$3,100	$11,151	$5,968	$21,468	$2,984	$10,734
Compressor Stations								
2a - Annual, 10,000 ppm	$1,225	$5,393	$612	$2,697	$1,010	$4,622	$505	$2,311
2a - Annual, 2,500 ppm	$1,604	$7,064	$802	$3,532	$1,390	$6,293	$695	$3,147
2a - Annual, 500 ppm	$1,679	$7,396	$840	$3,698	$1,465	$6,625	$732	$3,312
2b - Semiannual, 10,000 ppm	$1,429	$6,295	$715	$3,148	$1,215	$5,524	$607	$2,762
2b - Semiannual, 2,500 ppm	$1,666	$7,337	$833	$3,669	$1,452	$6,566	$726	$3,283
2b - Semiannual, 500 ppm	$1,722	$7,586	$861	$3,793	$1,508	$6,814	$754	$3,407
2c - Quarterly, 10,000 ppm	$1,610	$7,093	$805	$3,547	$1,396	$6,322	$698	$3,161
2c - Quarterly, 2,500 ppm	$1,778	$7,832	$889	$3,916	$1,564	$7,060	$782	$3,530
2c - Quarterly, 500 ppm	$1,830	$8,062	$915	$4,031	$1,616	$7,290	$808	$3,645

5.5.2 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 Regulatory Option, which was selected as a viable option for reducing fugitive emissions from fugitive emissions components located at production well sites and compressor stations.

5.5.2.1 Primary Environmental Impacts of Regulatory Options

Based on the discussion above, we consider Regulatory Option 1a, 1b, 2a (with a repair threshold of 2,500 ppm or 10,000 ppm) and 2b (with a repair threshold of 2,500 ppm or 10,000 ppm) for further consideration in setting standards for fugitive emissions from production well sites compressor stations.

- Regulatory Option 1a. Require the implementation of a fugitive emissions monitoring and repair program which includes annual monitoring of fugitive emissions components using OGI.
- Regulatory Option 1b. Require the implementation of a fugitive emissions monitoring and repair program which includes semiannual monitoring of fugitive emissions and components using OGI.
- Regulatory Option 2a - (2,500 ppm) - Require the implementation of a Method 21 monitoring and repair program which includes annual monitoring of fugitive emissions and components using Method 21 with a 2,500 ppm repair threshold.
- Regulatory Option 2a - (10,000 ppm) - Require the implementation of a Method 21 monitoring and repair program which includes annual monitoring of fugitive emissions and components using Method 21 with a 10,000 ppm repair threshold.
- Regulatory Option 2b - (2,500 ppm) - Require the implementation of a Method 21 monitoring and repair program which includes semiannual monitoring of fugitive emissions and components using Method 21 with a 2,500 ppm repair threshold.
- Regulatory Option 2b - (10,000 ppm) - Require the implementation of a Method 21 monitoring and repair program which includes semiannual monitoring of fugitive emissions and components using Method 21 with a 10,000 ppm repair threshold.

The number of oil and natural production well sites, gathering and boosting stations, transmission stations, and storage facilities that would be subject to the regulatory options listed above were presented in Table 5-10. In 2020, it was estimated that there would be 16,562 uncontrolled oil well sites, 5,518 uncontrolled gas well sites, 259 uncontrolled gathering and boosting stations, 6 uncontrolled transmission stations, and 15 uncontrolled storage facilities subject to these options. In 2025, it was estimated that there would be 100,175 uncontrolled oil well sites, 38,393 uncontrolled gas well sites, 1,554 uncontrolled gathering and boosting stations, 36 uncontrolled transmission stations, and 90 uncontrolled storage facilities subject to these options.

It was estimated that OGI monitoring and repair on an annual frequency can achieve an overall 40 percent VOC and CH_4 reduction over the life span of the facility and on a semiannual frequency can achieve an overall 60 percent VOC and CH_4 reduction. These percent reduction values were estimated based on information from the EPA white paper and an analysis by the Colorado Air Quality Control Commission. Nationwide emission reductions were estimated by applying this 40 and 60 percent VOC and CH_4 reduction to the uncontrolled baseline emissions presented in Table 5-11. In considering the two frequency options, we considered the implementation issues with respect to the monitoring and repair plan and we 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 both of these options as presented in Tables 5-30 and 5-31.

It was estimated that Method 21 monitoring and repair can achieve a range of VOC and CH_4 depending on the frequency of monitoring combined with the leak repair threshold. The percent reductions as presented in Table 5-18 range from 72 percent (semiannual frequency with 10,000 ppm leak repair threshold) to 98 percent (annual frequency with a 500 ppm leak repair threshold). These percent reductions were estimated using leak definition and monitoring frequency SOCMI emission factor data from the EPA Equipment Leak Protocol document. Nationwide emission reductions were estimated by applying these percent to the uncontrolled baseline emissions VOC and CH_4 emissions presented in Table 5-19. The nationwide impacts were estimated for six sub-options (2a and 2b sub-options) as presented in Tables 5-32 and 5-33.

5.5.2.2 Cost Impacts

<u>OGI Monitoring and Repair Plans (options 1a and 1b)</u>

The operational standards for Regulatory Option 1a include both 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 5-30) are estimated to be \$1,329 for oil and natural gas production well sites, \$10,124 for gathering and boosting stations, \$10,049 for transmission stations, and \$13,634 for storage facilities, which includes the costs for having a subcontractor do the semiannual 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 a semiannual OGI monitoring and repair program was calculated to be 105 thousand standard cubic feet per year (Mscf/yr) for a natural gas production well site and 25 Mscf/yr for an oil production well site. For the compressor stations, the potential natural gas saved was calculated to be 815 Mscf/yr for gathering and boosting stations, 1,292 Mscf/yr for transmission stations, and 3,405 Mscf/yr for storage facilities.[57] However, the value of the natural gas saved is not considered as an offset to costs for transmission and storage because we assume that operators of these facilities do not own the natural gas handled.

The operational standards for Regulatory Option 1b include both 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 5-31) are estimated to be $2,230 for oil and natural gas production well sites, $15,881 for gathering and boosting stations, $15,732 for transmission stations, and $22,902 for storage facilities, which includes the costs for having a subcontractor do 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 158 thousand standard cubic feet per year (Mscf/yr) for a natural gas production well site and 38 Mscf/yr for an oil production well site. For the compressor stations, the potential natural gas savings were calculated to be 1,222 Mscf/yr for gathering and boosting stations, 1,937 Mscf/yr for transmission stations, and 5,107 Mscf/yr for storage facilities.[58]

Applying the cost for the annual OGI monitoring and repair (Option 1a) to the estimated 16,562 oil production well sites and 5,518 natural gas production well sites in projected year 2020, the total nationwide costs were estimated to be $25.4 million, which includes an estimated annual savings of $4 million when natural gas savings are considered. Likewise, for projected year 2025, for 100,175 oil production well sites and 38,933 natural gas production well sites, the total nationwide cost was estimated to be $158.4 million, including annual savings estimated around $26.5 million when natural gas savings are considered. For the 259 new gathering and boosting, 6 transmission and 15 storage compressor stations, the nationwide costs were estimated to be $2 million in the year 2020, which includes annual savings of $0.8 million per year for gathering and boosting stations. For the 1,554 new gathering and

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[57] Natural gas savings calculated using the CH_4 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).
[58] Ibid.

boosting, 36 transmission and 90 storage facilities, the nationwide costs were estimated to be $12.3 million in the year 2025. Annual savings were estimated to be $5 million per year for gathering and boosting stations. No annual savings were estimated for transmission and storage facilities, because they do not own the natural gas that is compressed at their facilities. Table 5-30 summarizes the nationwide cost impacts for the projected years 2020 and 2025 for implementation of regulatory Option 1a.

Applying the cost for the semiannual OGI monitoring and repair to the estimated 16,562 oil production well sites and 5,518 natural gas production well sites in projected year 2020, the total nationwide costs were estimated to be $43.2 million, which includes an estimated annual savings of $6 million when natural gas savings are considered. Likewise, for projected year 2025, for 100,175 oil production well sites and 38,933 natural gas production well sites, the total nationwide cost was estimated to be $270.5 million, including annual savings estimated around $39.7 million when natural gas savings are considered. For compressor stations, which include 259 new gathering and boosting, 6 transmission and 15 storage facilities, the nationwide costs were estimated to be $3.3 million in the year 2020. Annual savings were estimated to be $1.3 million per year for gathering and boosting stations. For 1,554 new gathering and boosting, 36 transmission and 90 storage facilities, and the nationwide costs were estimated to be $19.7 million in the projected year 2025. Annual savings were estimated to be $7.6 million per year for gathering and boosting stations. No annual savings were estimated for transmission and storage facilities, because they do not own the natural gas that is compressed at their facilities. Table 5-31 summarizes the nationwide cost impacts for the projected years 2020 and 2025 for implementation of regulatory Option 1b.

Method 21 Monitoring and Repair Plans (Options 2a and 2b)

The operational standards for Regulatory Option 2a include both annual monitoring of fugitive emissions components using Method 21 and repair of fugitive emissions components that are found to be leaking during the survey. The two sub-options considered included leak repair thresholds of 10,000 ppm and 2,500 ppm. Without considering gas savings, the estimated annual costs for these surveys are estimated to range from $4,020 (annual at 10,000 ppm repair threshold) to $6,103 (semiannual at 2,500 ppm repair threshold) for oil and natural gas production well sites and from $37,203 to $55,860 for gathering and boosting, transmission and storage compressor stations. This cost includes the costs for conducting the Method21 survey, activities planning, repair costs, resurvey after repair, 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 Method21 monitoring and repair program were calculated to range from 189 thousand standard cubic feet per year (Mscf/yr) to 247 Mcf/yr for a natural gas production well site, from 45 to 59 Mscf/yr for an oil production well site, and 1,466 to 1,914 Mcf/yr for gathering and boosting compressor stations. The potential natural gas savings were calculated to range from 2,325 Mcf/yr to 3,035 Mcf/yr for transmission compressor stations and from 6,129 to 8,001 Mcf/yr for storage facility compressor stations. However, because gas handled by transmission and storage facilities is not typically owned by the operator, we do not consider this as gas saved with respect to offsetting of costs.

Applying the cost for the annual Method 21 monitoring and 10,000 ppm repair threshold to the estimated 16,562 oil production well sites and 5,518 natural gas production well sites in projected year 2020, the total nationwide costs were estimated to be $80.6 million, which includes an estimated annual savings of $8.2 million when natural gas savings are considered. Likewise, for projected year 2025, for 100,175 oil production well sites and 38,933 natural gas production well sites, the total nationwide cost was estimated to be $504.9 million, including annual savings estimated around $54.3 million when natural gas savings are considered. For compressor stations, the nationwide costs for 2020 for this option were estimated to be $8.7 million, including $1.7 million when natural gas savings are considered. For 2025 for compressor stations the nationwide costs for 2020 were estimated to be $52.1 million, including $10.4 million when natural gas savings are considered.

Applying the cost for the annual Method 21 monitoring and 2,500 ppm repair threshold to the estimated 16,562 oil production well sites and 5,518 natural gas production well sites in projected year 2020, the total nationwide costs were estimated to be $125.4 million, which includes an estimated annual savings of $9.4 million when natural gas savings are considered. Likewise, for projected year 2025, for 100,175 oil production well sites and 38,933 natural gas production well sites, the total nationwide cost was estimated to be $786.7 million, including annual savings estimated around $62.2 million when natural gas savings are considered. For compressor stations, the nationwide costs for 2020 for this option were estimated to be $13.7 million, including $2 million when natural gas savings are considered. For 2025 for compressor stations the nationwide costs were estimated to be $81.9 million, including $11.9 million when natural gas savings are considered. Table 5-32 summarizes the nationwide costs for the two sub-options under Option 2a (annual Method 21 monitoring at the 10,000 ppm and 2,500 ppm repair thresholds).

Applying the cost for the annual Method 21 monitoring and 500 ppm repair threshold to the estimated 16,562 oil production well sites and 5,518 natural gas production well sites in projected year 2020, the total nationwide costs were estimated to be $132.3 million, which includes an estimated annual savings of $9.8 million when natural gas savings are considered. Likewise, for projected year 2025, for 100,175 oil production well sites and 38,933 natural gas production well sites, the total nationwide cost was estimated to be $830.5 million, including annual savings estimated around $64.9 million when natural gas savings are considered. For compressor stations, the nationwide costs for 2020 for this option were estimated to be $15 million, including $2.1 million when natural gas savings are considered. For 2025 for compressor stations the nationwide costs were estimated to be $90 million, including $12.4 million when natural gas savings are considered. Table 5-32 summarizes the nationwide costs for the two sub-options under Option 2a (annual Method 21 monitoring at the 10,000 ppm, 2,500 ppm and 500 ppm repair thresholds).

Applying the cost for the semiannual Method 21 monitoring and 10,000 ppm repair threshold to the estimated 16,562 oil production well sites and 5,518 natural gas production well sites in projected year 2020, the total nationwide costs were estimated to be $91.8 million, which includes an estimated annual savings of $7.2 million when natural gas savings are considered. Likewise, for projected year 2025, for 100,175 oil production well sites and 38,933 natural gas production well sites, the total nationwide cost was estimated to be $575.8 million, including annual savings estimated around $47.7 million when natural gas savings are considered. For compressor stations, the nationwide costs for 2020 for this option were estimated to be $9.2 million, including $1.5 million when natural gas savings are considered. For 2025 for compressor stations the nationwide costs for 2020 were estimated to be $54.9 million, including $9.1 million when natural gas savings are considered.

Applying the cost for the semiannual Method 21 monitoring and 2,500 ppm repair threshold to the estimated 16,562 oil production well sites and 5,518 natural gas production well sites in projected year 2020, the total nationwide costs were estimated to be $135.8 million, which includes an estimated annual savings of $9.2 million when natural gas savings are considered. Likewise, for projected year 2025, for 100,175 oil production well sites and 38,933 natural gas production well sites, the total nationwide cost was estimated to be $852.3 million, including annual savings estimated around $60.9 million when natural gas savings are considered. For compressor stations, the nationwide costs for 2020 for this option were estimated to be $14 million, including $1.9 million when natural gas savings are considered. For 2025 for compressor stations the nationwide costs were estimated to be $83.8 million, including $11.6 million when natural gas savings are considered.

Applying the cost for the semiannual Method 21 monitoring and 500 ppm repair threshold to the estimated 16,562 oil production well sites and 5,518 natural gas production well sites in projected year 2020, the total nationwide costs were estimated to be $142.7 million, which includes an estimated annual savings of $9.7 million when natural gas savings are considered. Likewise, for projected year 2025, for 100,175 oil production well sites and 38,933 natural gas production well sites, the total nationwide cost was estimated to be $895.5 million, including annual savings estimated around $64.2 million when natural gas savings are considered. For compressor stations, the nationwide costs for 2020 for this option were estimated to be $15.3 million, including $2 million when natural gas savings are considered. For 2025 for compressor stations the nationwide costs were estimated to be $91.7 million, including $12.3 million when natural gas savings are considered.

Table 5-33 summarizes the nationwide costs for the two Option 2b sub-options (semiannual Method 21 monitoring at the 10,000 ppm, 2,500 ppm, and 500 ppm repair thresholds).

Table 5-30. Nationwide Emission and Cost Analysis for Regulatory Option 1a – Annual OGI Monition 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	CH_4	VOC	without savings	with savings
Projected Year 2020							
Gas Well Site	5,518	$1,329	$908	10,019	2,785	$7.3	$5.0
Oil Well Site	16,562	$1,329	$1,228	7,205	2,003	$22.0	$20.3
Well Sites	22,080	NA	NA	17,224	4,788	$29.3	$25.4
Gathering & Boosting	259	$10,124	$6,865	3,641	1,012	$2.6	$1.8
Transmission	6	$10,049	$10,049	150	4	$0.1	$0.1
Storage	15	$13,634	$13,634	987	27	$0.2	$0.2
Compressor Stations	280	NA	NA	4,777	1,043	$2.9	$2.0
Projected Year 2025							
Gas Well Site	38,933	$1,329	$908	70,691	19,650	$51.7	$35.4
Oil Well Site	100,175	$1,329	$1,228	43,577	12,113	$133.1	$123.0
Well Sites	139,108	NA	NA	114,267	31,763	$184.9	$158.4
Gathering & Boosting	1,554	$10,124	$6,865	21,845	6,072	$15.7	$10.7
Transmission	36	$10,049	$10,049	898	25	$0.4	$0.4
Storage	90	$13,634	$13,634	5,919	164	$1.2	$1.2
Compressor Stations	1,680	NA	NA	28,662	6,261	$17.3	$12.3

Table 5-31. Nationwide Emission and Cost Analysis for Regulatory Option 1b – 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	CH_4	VOC	without savings	with savings
Projected Year 2020							
Gas Well Site	5,518	$2,230	$1,599	15,029	4,178	$12.3	$8.8
Oil Well Site	16,562	$2,230	$2,079	10,807	3,004	$36.9	$34.4
Well Sites	22,080	NA	NA	25,835	7,182	$49.2	$43.2
Gathering & Boosting	259	$15,881	$10,993	5,461	1,518	$4.1	$2.8
Transmission	6	$15,732	$15,732	225	6	$0.1	$0.1
Storage	15	$22,902	$22,902	1,480	41	$0.3	$0.3
Compressor Stations	280	NA	NA	7,165	1,565	$4.6	$3.3
Projected Year 2025							
Gas Well Site	38,933	$2,230	$1,599	106,036	29,475	$86.8	$62.2
Oil Well Site	100,175	$2,230	$2,079	65,365	18,170	$223.4	$208.2
Well Sites	139,108	NA	NA	171,401	47,645	$310.2	$270.5
Gathering & Boosting	1,554	$15,881	$10,993	32,767	9,108	$24.7	$17.1
Transmission	36	$15,732	$15,732	1,347	37	$0.6	$0.6
Storage	90	$22,902	$22,902	8,879	246	$2.1	$2.1
Compressor Stations	1,680	NA	NA	42,993	9,391	$27.3	$19.7

Table 5-32. Nationwide Emission and Cost Analysis for Regulatory Option 2a – Annual Method 21 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	CH_4	VOC	without savings	with savings
Projected Year 2020							
10,000 ppm							
Gas Well Site	5,518	$4,020	$3,157	20,539	5,709	$22.2	$17.4
Oil Well Site	16,562	$4,020	$3,813	14,769	4,106	$66.6	$63.2
Well Sites	22,080	NA	NA	35,308	9,815	$88.8	$80.6
Gathering & Boosting	259	$37,203	$30,523	7,464	2,075	$9.6	$7.9
Transmission	6	$37,203	$37,203	307	8	$0.2	$0.2
Storage	15	$37,203	$37,203	2,022	56	$0.6	$0.6
Compressor Stations	280	NA	NA	9,793	2,139	$10.4	$8.7
2,500 ppm							
Gas Well Site	5,518	$6,103	$5,113	23,545	6,545	$33.7	$28.2
Oil Well Site	16,562	$6,103	$5,866	16,931	4,706	$101.1	$97.1
Well Sites	22,080	NA	NA	40,475	11,251	$134.7	$125.4
Gathering & Boosting	259	$55,860	$48,203	8,556	2,378	$14.5	$12.5
Transmission	6	$55,860	$55,860	352	10	$0.3	$0.3
Storage	15	$55,860	$55,860	2,318	64	$0.8	$0.8
Compressor Stations	280	NA	NA	11,226	2,452	$15.6	$13.7

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	CH_4	VOC	without savings	with savings
500 ppm							
Gas Well Site	5,518	$6,437	$5,406	24,547	6,823	$35.5	$29.8
Oil Well Site	16,562	$6,437	$6,190	17,651	4,907	$106.6	$102.5
Well Sites	22,080	NA	NA	42,198	11,730	$142.1	$132.3
Gathering & Boosting	259	$60,973	$52,990	8,920	2,480	$15.8	$13.7
Transmission	6	$60,973	$60,973	367	10	$0.4	$0.4
Storage	15	$60,973	$60,973	2,417	67	$0.9	$0.9
Compressor Stations	280	NA	NA	11,704	2,557	$17.1	$15.0
Projected Year 2025							
10,000 ppm							
Gas Well Site	38,933	$4,020	$3,157	144,916	40,283	$156.5	$122.9
Oil Well Site	100,175	$4,020	$3,813	89,332	24,832	$402.7	$382.0
Well Sites	139,108	NA	NA	234,248	65,115	$559.2	$504.9
Gathering & Boosting	1,554	$37,203	$30,523	44,781	12,448	$57.8	$47.4
Transmission	36	$37,203	$37,203	1,841	51	$1.3	$1.3
Storage	90	$37,203	$37,203	12,134	336	$3.3	$3.3
Compressor Stations	1680	NA	NA	58,757	12,835	$62.5	$52.1
2,500 ppm							
Gas Well Site	38,933	$6,103	$5,113	163,123	46,178	$237.6	$199.1

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	CH_4	VOC	without savings	with savings
Oil Well Site	100,175	$6,103	$5,866	102,405	28,466	$611.3	$587.6
Well Sites	139,108	NA	NA	268,528	2,147	$848.9	$786.7
Gathering & Boosting	1,554	$55,860	$48,203	51,335	14,270	$86.8	$74.9
Transmission	36	$55,860	$55,860	2,111	58	$2.0	$2.0
Storage	90	$55,860	$55,860	13,910	385	$5.0	$5.0
Compressor Stations	1680	NA	NA	67,355	14,713	$93.8	$81.9
500 ppm							
Gas Well Site	38,933	$6,437	$5,406	173,192	48,143	$250.6	$210.5
Oil Well Site	100,175	$6,437	$6,190	106,763	29,677	$644.8	$620.1
Well Sites	139,108	NA	NA	279,954	77,820	$895.4	$830.5
Gathering & Boosting	1,554	$60,973	$52,990	53,519	14,877	$94.8	$82.3
Transmission	36	$60,973	$60,973	2,200	61	$2.2	$2.2
Storage	90	$60,973	$60,973	14,502	401	$5.5	$5.5
Compressor Stations	1680	NA	NA	70,222	15,339	$102.4	$90.0

Table 5-33. Nationwide Emission and Cost Analysis for Regulatory Option 2b – Semiannual Method 21 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	CH_4	VOC	without savings	with savings
Projected Year 2020							
10,000 ppm							
Gas Well Site	5,518	$4,482	$3,725	18,034	5,013	$24.7	$20.6
Oil Well Site	16,562	$4,482	$4,301	12,968	3,605	$74.2	$71.2
Well Sites	22,080	NA	NA	31,002	8,618	$99.0	$91.8
Gathering & Boosting	259	$38,128	$32,263	6,553	1,822	$9.9	$8.4
Transmission	6	$38,128	$38,128	269	7	$0.2	$0.2
Storage	15	$38,128	$38,128	1,776	49	$0.6	$0.6
Compressor Stations	280	NA	NA	8,599	1,878	$10.7	$9.2
2,500 ppm							
Gas Well Site	5,518	$6,565	$5,597	23,044	6,406	$36.2	$30.9
Oil Well Site	16,562	$6,565	$6,333	16,570	4,606	$108.7	$104.9
Well Sites	22,080	NA	NA	39,614	11,012	$145.0	$135.8
Gathering & Boosting	259	$56,785	$49,291	8,374	2,328	$14.7	$12.8
Transmission	6	$56,785	$56,785	344	10	$0.3	$0.3
Storage	15	$56,785	$56,785	2,269	63	$0.9	$0.9
Compressor Stations	280	NA	NA	10,987	2,400	$15.9	$14.0

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	CH_4	VOC	without savings	with savings
500 ppm							
Gas Well Site	5,518	$6,899	$5,879	24,296	6,754	$38.1	$32.4
Oil Well Site	16,562	$6,899	$6,655	17,471	4,857	$114.3	$110.2
Well Sites	22,080	NA	NA	41,767	11,610	$152.3	$142.7
Gathering & Boosting	259	$61,898	$53,996	8,829	2,454	$16.0	$14.0
Transmission	6	$61,898	$61,898	363	10	$0.4	$0.4
Storage	15	$61,898	$61,898	2,392	66	$0.9	$0.9
Compressor Stations	280	NA	NA	11,584	2,530	$17.3	$15.3
Projected Year 2025							
10,000 ppm							
Gas Well Site	38,933	$4,482	$3,725	127,243	35,370	$174.5	$145.0
Oil Well Site	100,175	$4,482	$4,301	78,438	21,804	$449.0	$430.8
Well Sites	139,108	NA	NA	205,681	57,174	$623.5	$575.8
Gathering & Boosting	1,554	$38,128	$32,263	39,320	10,930	$59.3	$50.1
Transmission	36	$38,128	$38,128	1,617	45	$1.4	$1.4
Storage	90	$38,128	$38,128	10,654	295	$3.4	$3.4
Compressor Stations	1680	NA	NA	51,591	11,270	$64.1	$54.9
2,500 ppm							
Gas Well Site	38,933	$6,565	$5,597	162,588	45,195	$255.6	$217.9

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	CH_4	VOC	without savings	with savings
Oil Well Site	100,175	$6,565	$6,333	100,226	27,860	$657.6	$634.4
Well Sites	139,108	NA	NA	262,814	73,056	$913.2	$852.3
Gathering & Boosting	1,554	$56,785	$49,291	50,243	13,966	$88.2	$76.6
Transmission	36	$56,785	$56,785	2,066	57	$2.0	$2.0
Storage	90	$56,785	$56,785	13,614	377	$5.1	$5.1
Compressor Stations	1680	NA	NA	65,922	14,400	$95.4	$83.8
500 ppm							
Gas Well Site	38,933	$6,899	$5,879	171,424	47,652	$268.6	$228.9
Oil Well Site	100,175	$6,899	$6,655	105,673	29,375	$691.2	$666.7
Well Sites	139,108	NA	NA	277,098	77,026	$959.8	$895.5
Gathering & Boosting	1,554	$61,898	$53,996	52,973	14,725	$96.2	$83.9
Transmission	36	$61,898	$61,898	2,178	60	$2.2	$2.2
Storage	90	$61,898	$61,898	14,354	397	$5.6	$5.6
Compressor Stations	1680	NA	NA	69,505	15,183	$104.0	$91.7

5.5.2.3 Nationwide Impacts Excluding Low Producing Natural Gas and Oil Wells

We also evaluated an alternative nationwide impact scenario that accounts for well sites that produce relatively little crude oil and/or natural gas. Under this scenario, low producing wells would not be subject to fugitive emissions monitoring provisions. While there are several criteria for defining a low-producing well, we believe the definition of a "stripper well" in Internal Revenue Services (IRS) regulations, is consistent with the type of well which would be considered low-producing under this 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". [59]

From the 2012 natural gas and oil well completion data derived from HPDI as described in section 5.3.2 above, we determined the percentage of wells that meet the above definition and deducted that number of wells from the nationwide population. To determine the barrel equivalents for the HPDI natural gas production data, we converted the first month of natural gas production data for each well using 0.178 barrel equivalents per Mcf of natural gas produced. If the well also produced oil, the number of barrels of oil produced was added to the barrel equivalents calculated for the natural gas. Based on this definition, of the 35,454 oil well completions in 2012, 15,354 of the oil wells (or 43 percent) met the definition of a low-producing well. Of the 8,459 natural gas completions in 2012, 2,567 (or 30 percent) natural gas wells met the definition of a low-producing well. For our analysis, we assume that the percentages of low-producing wells in the overall number of completions in 2012 would also apply to the overall number of well sites. Using the estimated percentage of low-producing wells, we reduced the number of well sites in the 2020 and 2025 activity counts to represent the estimated population of well sites that would be covered by the NSPS fugitive emissions requirements taking into account that wells producing no more than 15 barrel equivalents of oil per day would not be subject to the requirements.

Based on those percentages, we estimated 3,863 natural gas well sites and 9,440 oil well sites will be subject to the fugitive emissions monitoring requirements in 2020 and 27,2533 natural gas well sites and 57,100 oil wells sites will be subject by 2025. Tables 5-34 through 5-37 summarize the estimated nationwide cost impacts for this alternative population of well sites for each of the regulatory options discussed above.

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[59] 26 U.S.C. 613A(c)(6)(E).

Table 5-34. Nationwide Emission and Cost Analysis for Regulatory Option 1a (Excluding Low-Producing Well Sites) – Annual OGI Monition 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	CH_4	VOC	without savings	with savings
Projected Year 2020							
Gas Well Site	3,863	$1,329	$908	7,014	1,950	$5.1	$3.5
Oil Well Site	9,440	$1,329	$1,228	4,106	1,141	$12.5	$11.6
Well Sites	13,303	NA	NA	11,120	3,091	$17.7	$15.1
Projected Year 2025							
Gas Well Site	27,253	$1,329	$908	49,483	13,755	$36.2	$24.8
Oil Well Site	57,100	$1,329	$1,228	24,839	6,905	$75.9	$70.1
Well Sites	84,353	NA	NA	74,322	20,660	$112.1	$94.9

Table 5-35. Nationwide Emission and Cost Analysis for Regulatory Option 1b (Excluding Low-Producing Well Sites) – Semiannual OGI Monition 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	CH_4	VOC	without savings	with savings
Projected Year 2020							
Gas Well Site	3,862	$2,230	$1,599	10,518	2,924	$8.6	$6.2
Oil Well Site	9,440	$2,230	$2,079	6,160	1,712	$21.0	$19.6
Well Sites	13,302	NA	NA	16,678	4,636	$29.7	$25.8
Projected Year 2025							
Gas Well Site	27,253	$2,230	$1,599	74,225	20,633	$60.8	$43.6
Oil Well Site	57,100	$2,230	$2,079	37,258	10,357	$127.3	$118.7
Well Sites	84,353	NA	NA	111,483	30,989	$188.1	$162.3

Table 5-36. Nationwide Emission and Cost Analysis for Regulatory Option 2a (Excluding Low-Producing Well Sites) – Annual Method 21 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	CH_4	VOC	without savings	with savings
Projected Year 2020							
10,000 ppm							
Gas Well Site	3,863	$4,020	$3,157	14,379	3,997	$15.5	$12.2
Oil Well Site	9,440	$4,020	$3,813	8,418	2,340	$37.9	$36.0
Well Sites	13,303	NA	NA	22,797	6,337	$53.5	$48.2
2,500 ppm							
Gas Well Site	3,863	$6,103	$5,113	16,483	1,212	$23.6	$19.8
Oil Well Site	9,440	$6,103	$5,866	9,650	236	$57.6	$55.4
Well Sites	13,303	NA	NA	26,133	1,449	$81.2	$75.1
500 ppm							
Gas Well Site	3,863	$6,437	$5,406	17,184	4,777	$24.9	$20.9
Oil Well Site	9,440	$6,437	$6,190	10,061	2,797	$60.8	$58.4
Well Sites	13,303	NA	NA	27,245	7,573	$85.6	$79.3
Projected Year 2025							
10,000 ppm							
Gas Well Site	27,253	$4,020	$3,157	101,441	28,198	$109.6	$86.0
Oil Well Site	57,100	$4,020	$3,813	50,920	14,154	$229.5	$217.7
Well Sites	84,353	NA	NA	152,360	42,352	$339.1	$303.8

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	CH_4	VOC	without savings	with savings
2,500 ppm							
Gas Well Site	27,253	$6,103	$5,113	116,285	1,229	$166.3	$139.4
Oil Well Site	57,100	$6,103	$5,866	58,371	236	$348.5	$334.9
Well Sites	84,353	NA	NA	174,657	1,466	$514.8	$474.3
500 ppm							
Gas Well Site	27,253	$6,437	$5,406	121,234	33,700	$175.4	$147.3
Oil Well Site	57,100	$6,437	$6,190	60,855	16,916	$367.6	$353.4
Well Sites	84,353	NA	NA	182,089	50,616	$543.0	$500.8

Table 5-37~~37~~. Nationwide Emission and Cost Analysis for Regulatory Option 2b (Excluding Low-Producing Well Sites) – Semiannual Method 21 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	CH_4	VOC	without savings	with savings
Projected Year 2020							
10,000 ppm							
Gas Well Site	3,863	$4,482	$3,725	12,622	3,509	$17.3	$14.4
Oil Well Site	9,440	$4,482	$4,301	7,392	2,055	$42.3	$40.6
Well Sites	13,302	NA	NA	20,014	5,563	$59.6	$55.0
2,500 ppm							
Gas Well Site	3,863	$6,565	$5,597	16,128	1,186	$25.4	$21.6
Oil Well Site	9,440	$6,565	$6,333	9,445	231	$62.0	$59.8
Well Sites	13,302	NA	NA	25,573	1,418	$87.3	$81.4
500 ppm							
Gas Well Site	3,863	$6,899	$5,879	17,009	4,728	$26.7	$22.7
Oil Well Site	9,440	$6,899	$6,655	9,958	2,768	$65.1	$62.8
Well Sites	13,303	NA	NA	26,967	7,496	$91.8	$85.5
Projected Year 2025							
10,000 ppm							
Gas Well Site	27,253	$4,482	$3,725	89,070	24,759	$122.2	$101.5
Oil Well Site	57,100	$4,482	$4,301	44,710	12,428	$255.9	$245.6
Well Sites	84,353	NA	NA	133,780	37,187	$378.1	$347.1

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**	**CH_4**	**VOC**	**without savings**	**with savings**
2,500 ppm							
Gas Well Site	27,253	$6,565	$5,597	113,811	1,203	$178.9	$152.5
Oil Well Site	57,100	$6,565	$6,333	57,129	231	$374.9	$361.6
Well Sites	84,353	NA	NA	170,941	1,435	$553.8	$514.1
500 ppm							
Gas Well Site	27,253	$6,899	$5,879	119,997	33,356	$188.0	$160.2
Oil Well Site	57,100	$6,899	$6,655	60,234	16,744	$394.0	$380.0
Well Sites	84,353	NA	NA	180,231	50,100	$582.0	$540.2

6.0 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. This chapter describes pneumatic controllers in the transmission and storage segment, including their function and associated emissions. Standards are already in place for pneumatic controllers in the production and processing segment; therefore they are not discussed here. 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.

6.1 Process Description

6.1.1 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.[60]

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 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,

[60] 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.

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 pressure[61] 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 6.2.2) 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. 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, we 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 to power an instrument air compressor, mechanical or solar-powered, electrically powered pneumatic devices can be used. 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

[61] Memorandum to Bruce Moore, U.S. EPA from Denise Grubert, EC/R. Meeting Minutes from EPA Meeting with the API. October 2011.

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.[62]

6.2 Emissions Data and Information

6.2.1 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, numerous studies and sources of information were consulted. Table 6-1 presents these studies and sources of information with an indication of the type of relevant information contained in each resource.

Table 6-1. 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	2013	Nationwide	X	
Inventory of GHG Emissions and Sinks: 1990-2012[b]	EPA	2014	Nationwide/ Regional	X	
CH_4 Emissions from the Natural Gas Industry[c]	GRI/EPA	1996	Nationwide	X	
CH_4Emissions from the Petroleum Industry (draft)[d]	EPA	1996	Nationwide	X	
CH_4 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		X	X
Measurements of CH_4 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	

[62] 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.

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 CH_4 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. Methodology for Estimating CH_4 and CO_2 Emissions from Natural Gas Systems. GHG Inventory: Emission and Sinks 1990-2008. Washington, DC. and U.S EPA. Methodology for Estimating CH_4 and CO_2 Emissions from Petroleum Systems. GHG Inventory: Emission and Sinks 1990-2008. 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 Western States. 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. Memorandum to Bruce Moore from Heather Brown. Gas Composition Methodology. July 2011.
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.

6.2.2 Representative Pneumatic Device Emissions

Continuous bleed pneumatic controllers can be classified into two types based on their emissions 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.[63]

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 rule[64], the Inventory of GHG Emissions and Sinks, new studies, as well as pneumatic controller vendor information obtained

[63] 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.
[64] Available at http://www.epa.gov/ghgreporting/reporters/subpart/w.html.

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 2013 data from GHGRP, and new measurement data from Subramanian et al. 2015, and Allen et al. 2014. GHGRP reported methane emissions for 2013 are 190,008 tons CO_2e in transmission, and 111,555 tons CO_2e 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 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.[65,66] 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-1A 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 CH_4 and VOC using a representative gas composition.[67]

The specific ratios from the representative gas composition were 0.908 lbs of CH_4 per pound of natural gas and 0.0277 lbs VOC per pound CH_4. Table 6-2 summarizes the estimated bleed emissions for a representative pneumatic controller by industry segment and device type.

[65] U.S. EPA. GHG Emissions Reporting From the Petroleum and Natural Gas Industry: Background TSD. Climate Change Division. Washington, DC. November 2010.
[66] All rates are listed at an assumed supply gas pressure of 20 psig.
[67] See footnote 45.

Table 6-2. Average Bleed Emission Estimates per Pneumatic Controller in the Natural Gas Transmission and Storage Segment[a, b]

High-Bleed (tpy)		Low-Bleed (tpy)	
CH_4	**VOC**	**CH_4**	**VOC**
3.013	0.083	0.227	0.00628

a. The conversion factor used in this analysis is 1,000 cubic feet (Mcf) of CH_4 is equal to 0.0208 tons CH_4.
b. Natural gas transmission and storage emission factors for continuous bleed controllers were derived from Table W-1A of Subpart W.

6.3 Nationwide Emissions from New Sources

6.3.1 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 6-2. The number of new pneumatic devices installed for a typical year was determined using the methodologies described in section 6.3.2 of this chapter.

6.3.2 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 only the years with an increase in pneumatic controllers.

The number of facilities estimated in absence of 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.

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 raw 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.[68] 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 6-3 summarizes the estimated number of new devices installed per year.

Table 6-3. 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**
558	262	820

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.

6.3.3 Emission Estimates

Nationwide baseline emission estimates for pneumatic devices for new sources in a typical year are summarized in Table 6-4. 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 6-4. 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)	
CH_4	VOC		CH_4	VOC
3.013	0.083	262	790.5	21.9

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 CH_4 was used.

6.4 Control Techniques

Several options to reduce emissions have been developed over the years to reduce emissions from pneumatic controllers. Table 6-5 provides a summary of these options for reducing emissions from pneumatic controllers including: instrument air, non-gas driven controls, and enhanced maintenance. The

[68] See footnote 51.

use of instrument air systems, as discussed in the 2012 NSPS TSD[69], 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 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 would be 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 emissions 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.

[69] See footnote 4.

Table 6-5. 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 6.4.2. 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 lose 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.

6.4.1 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 6-6, the average achievable reduction in emissions per controller is estimated to be approximately 2.79 tons of CH_4 and 0.077 tons of VOC. As noted in section 6.2, 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 6-6. 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 Emissions Reductions - High-Bleed Replaced with Low-Bleed[a] (tpy)	
CH_4	**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 6-2.

6.4.2 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.[70] This corresponds to 210 new high-bleed devices in the production segment (out of 262) 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 precise control include transient (non-steady) situations where a gas flow rate may fluctuate widely or

[70] See footnote 49.

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.

6.4.3 Cost Impacts

As described in Section 6.2.2, 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.[71] As Table 6-7 indicates, the average cost for a low bleed pneumatic is $2,471, while the average cost for a high bleed is $2,698.[72] 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 6-7. Cost Projections for Representative Pneumatic Controllers (2012)[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 to the sales line exists, 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 allocated all of the costs to each pollutant separately. The second method prorated costs among the pollutants that a given technology reduced (i.e., CH4 and VOC). This proration was based on estimates of the percentage reduction expected for each pollutant. Table 6-8 provides a summary of low-bleed pneumatic cost of control.

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[71] Ibid.

[72] Costs are estimated in 2012 U.S. Dollars.

Table 6-8. Cost-of Control for Low-Bleed Pneumatic Controllers versus High Bleed Pneumatics for the Transmission and Storage Segment (2012)

Method	Incremental Capital Cost Per Unit[a] ($)	Total Annual Cost Per Unit[b] ($/year)	Emissions Reductions (tpy)		Cost of Control ($/ton)	
			CH_4	VOC	CH_4	VOC
Standard 100%	$227	$24.95	2.79	0.077	$9	$323
Prorated 50/50	$227	$24.95	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.

6.4.4 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.

6.5 Regulatory Options

The affected facility definition for pneumatic controller is defined as a single natural gas pneumatic controller. Therefore, pneumatic controllers would be subject to a New Source Performance Standard (NSPS) at the time of installation. The following Regulatory alternatives were evaluated:

- Regulatory Option 1. Establish an emissions limit equal to 0 scfh.
- Regulatory Option 2. Establish an emissions limit equal to 6 scfh.

6.5.1 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 to be unreasonable. Therefore Regulatory option 1 was rejected for facilities in the transmission and storage segment.

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, Regulatory Option 2 was accepted for locations outside of natural gas processing plants.

6.5.2 Nationwide Impacts of Regulatory Options

Table 6-9 summarize the costs impacts of the selected regulatory option for the natural gas transmission and storage segment. It is estimated to affect 210 new transmission and storage pneumatic controllers per year with nationwide capital cost of $47,670 and annual costs of $5,250 for projected year 2020. For the projected year 2025, we estimate the number of new affected facilities for the years 2020 through 2025. As mentioned above, because the natural gas processed by the facilities within the transmission and storage segment is not necessarily owned by the operator, no gas savings is considered for this segment.

Table 6-9. Nationwide Cost and Emission Reduction Impacts for Selected Regulatory Option

Number of Affected Facilities[a]	Capital Cost Per Controller[b] ($)	Annual Costs ($/year)	Nationwide Emission Reductions (tpy)		Total Nationwide Costs ($/year)	
			CH_4	VOC	Capital Cost	Annualized Cost
Projected Year 2020						
210	$227	$25	585	16	$47,670	$5,250
Projected Year 2025						
1,260	$227	$25	3,511	97	$286,020	$31,680

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 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.

7.0 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."[73] 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]."[74] 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.

7.1 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."[75] 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 CH_4 emissions include "the frequency of operation, the size of the unit, the supply gas pressure, and the inlet CH_4 composition."[76]

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."[77] 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.

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

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[73] 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.
[74] See footnote 48.
[75] Ibid.
[76] Ibid.
[77] U.S. EPA OAQPS. Oil and Natural Gas Sector Pneumatic Devices. April 2014.

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."[78]

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.[79]

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 H_2S 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.[80]

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.[81]

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

[78] See footnote 48.
[79] Ibid.
[80] Ibid.
[81] GlobalSpec. Diaphragm Pumps Information. Available at http://www.globalspec.com/learnmore/flow_transfer_control/pumps/diaphragm_pumps.

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.[82] The application of electrical controls is further elaborated in Section 7.3.

7.1.1 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 7-1 lists these references with an indication of the type of relevant information contained in each study.

Table 7-1. 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: 1990-2012	EPA	2012	Nationwide/ Regional	X	
CH_4 Emissions from the Natural Gas Industry	GRI/EPA	1996	Nationwide	X	
CH_4 Emissions from the Petroleum Industry	EPA	1999	Nationwide	X	
Natural Gas STAR Program	EPA	2012	Study Specific	X	X

7.1.1.2 Representative Pneumatic Pump Emissions

The CH_4 emission estimates for pneumatic pumps are separated into two categories for the GRI/EPA reports; CIPs (GRI/EPA, 1996d) and gas-assisted glycol pumps (GRI/EPA, 1996f). A summary of the report on CIPs is provided in the following sections.

[82] 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.

For this analysis, the EPA consulted information in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic pumps[83,84], Subpart W of the GHG Reporting rule[85], U.S. GHG Natural Gas and Petroleum Inventories[86], and U.S. EPA GRI Report[87]. Subpart W and U.S. GHG Inventories use the emission factors form the U.S. EPA GRI Report. Similarly, EPA determined that the best available emissions 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 U.S. EPA GHG Inventory. Since publication of the white paper, additional data have become available on emissions from pumps, including GHGRP 2013 reporting year data. In 2013, reported methane emissions from chemical injection pumps in the production segment were 3,046,012 tons of CO_2e.

The basic approach used for this analysis was to first approximate CH_4 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.[88] The specific ratios from the gas composition used for this analysis were 0.278 lbs VOC per pound CH_4 per pound CH_4 in the production and processing segments, and 0.0277 lbs VOC per pound CH_4 in the transmission and storage segment. Table 7-2 summarizes the estimated bleed emission factors for a representative pneumatic pump by industry segment.

[83] 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.
[84] 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.
[85] U.S. Environmental Protection Agency. Mandatory Reporting of Greenhouse Gases from Petroleum and Natural Gas Systems – Subpart W. Washington, DC. November 2010.
[86] 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
[87] 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).
[88] See footnote 5.

Table 7-2. 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	CH_4	CH_4	VOC
Production				
Diaphragm	22.45	163	3.46	0.96
Piston	2.48	18	0.38	0.11
Processing				
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
Transmission				
Diaphragm	20.05	163	3.46	0.1
Piston	2.21	18	0.38	0.01
Storage				
Diaphragm	20.05	163	3.46	0.1
Piston	2.21	18	0.38	0.01

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 5.1 – Diaphragm Pumps and 5.2 – Piston Pumps.
b. Assumes 8760 hrs/yr and volumetric fraction of methane is 82.9% of natural gas in natural gas production and processing and 92.8% of natural gas in natural gas transmission and underground storage.
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 and 0.0277 VOC content per pound of methane in natural gas transmission and underground storage.

7.2 Nationwide Emissions from New Sources

7.2.1 Approach

Nationwide emissions from newly installed natural gas CIPs for a typical year were calculated by estimating the count of CIPs installed in a typical year and multiplying by the estimated annual emissions per device listed in Table 7-2. The count of new CIPs installed for a typical year was determined for each segment of the industry including natural gas production (which includes natural gas gathering and boosting), natural gas processing, and natural gas transmission and storage. The methodologies that determined the estimated count of new CIPs installed in a typical year is provided below.

7.2.2 Population of CIPs Installed Annually

For the natural gas production segment, which includes natural gas gathering and boosting, the count of new CIPs installed in a typical year was estimated by reviewing the annual count of CIPs 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 CIPs in each inventory over this period. For all the years, the annual counts of new CIPs 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 1480 for natural gas and 803 for oil. Because of the fluctuation in the count of new CIPs from the years 1990 to 2012, it was assumed that the 10-year average change represented a better estimate of the current growth of CIPs. Therefore, for this analysis, the counts of new CIPs that would be affected sources under the proposed NSPS in each of the years 2012, 2020 and 2025 were estimated to be 1,480 for natural gas and 803 for oil.

To forecast the count of CIPs replaced in a *typical* year, age and count of gas and oil wells for 2013 were extracted from DI Desktop®. The age of the pneumatic pump was assumed to be the age of the well. Based on expert judgment, 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 2020, the typical year for this analysis, the replacement count for CIPs was estimated to be 340 diaphragm pumps and 340 piston pumps.

The GHG Inventory[89] does not estimate any emissions from CIPs for the natural gas processing, natural gas transmission and storage segments. CIP data are not reported in GHGRP for these segments. For this analysis, the EPA assumed that CIPs are not used in these segments.

Once the population counts of pneumatic pumps in each segment were established, the count of CIPs was split into diaphragm and piston. Similar to the assumption used in the EPA/GRI Report,[90] for new and replaced pumps for each segment we assumed 50 percent of the pumps to be diaphragm and 50 percent of the pumps to be piston pumps. Table 7-3 below summarizes the estimated count of new pumps installed per year.

[89] See footnote 80
[90] See footnote 81.

Table 7-3. Estimated Count of Pneumatic Devices Installed in a Typical Year

Segment/Pump Type	Number of New Pumps
Production/Diaphragm	1,480
Production/Piston	1,480
Processing/Diaphragm and Piston	0
Transmission/Diaphragm and Piston	0
Storage/Diaphragm and Piston	0

7.2.3 Emission Estimates

Nationwide baseline emission estimates for pneumatic pumps for new sources in a typical year are summarized in Table 7-4 by industry segment and pump type.

Table 7-4. Nationwide Baseline Emissions from Representative Chemical Injection 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)	
		CH_4	VOC	CH_4	VOC
Production/Diaphragm	1,480	3.46	0.96	5,121	1,423
Production/Piston	1,480	0.38	0.11	562	156
Processing/Diaphragm	0	3.46	0.9600	0	0
Processing/Piston	0	0.38	0.11	0	0
Transmission/Diaphragm	0	3.46	0.1	0	0
Transmission/Piston	0	0.38	0.01	0	0
Storage/Diaphragm	0	3.46	0.1	0	0
Storage/Piston	0	0.38	0.01	0	0
			Totals	5,683	1,579
			Total Production	5,683	1,579
			Total Processing	0	0
			Total Transmission	0	0
			Total Storage	0	0

a. From Table 7-2.
b. From Table 7-3.

7.3 Control Techniques

Gas-driven chemical pumps emit CH_4 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 7-5 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. Identified emission control options for gas-driven pumps are described in the following section.

Table 7-5. 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, when applicable can result in 100 percent reduction in emissions where applicable.	Capital costs for converting to solar pumps is approximately $2,300 per device
Covert 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[91]~~[86]~~	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 7.3.3 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 CH_4 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 $1,500 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 CH_4 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 CH_4 emissions through gas capture where emission reduction efficiencies are typically 95 percent. Routing natural gas to a VRU is	Capital costs will vary depending on the distance of pipeline necessary, but are estimated to be approximately $1,500 per device.

Option	Description	Applicability/Effectiveness	Estimated Cost Range
		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.

7.3.1 Solar Pumps

7.3.1.1 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 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. We estimate converting natural gas-driven chemical pumps to solar-powered pumps can reduce CH_4 emissions by 3.46 tons per year per diaphragm pump and 0.38 tons per year per piston pump for all segments.[91] Based on the gas composition for natural gas in the production segment, we estimate 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, we estimate that replacement of a natural gas-driven pump with a solar-powered pump will reduce CH_4 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.

7.3.1.2 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.

7.3.1.3 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"[92], the cost for solar-powered electric pumps are

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[91] U.S. EPA. PRO Fact Sheet No. 202. Convert Natural Gas-Driven Chemical Pumps. Available at http://www.epa.gov/gasstar/documents/convertgasdrivenchemicalpumpstoinstrumentair.pdf.
[92] See footnote 77.

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). We estimate 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 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. We estimate 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 $72 per year per piston pump.

7.3.1.4 Secondary Impacts

No secondary impacts from conversion to solar powered pumps are expected.

7.3.2 Electric Pumps

7.3.2.1 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 7-6, and converting gas-driven chemical pumps to an electric pump can reduce CH_4 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, we estimate 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, we estimate that replacement of a pneumatic pump with an electric pump will reduce CH_4 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.

7.3.2.2 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 reliable source of electricity. These pumps are, therefore, more common at processing plants or large dehydration facilities that have access to reliable power.

7.3.2.3 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"[93] 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.[94] 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 $506 for a piston. In addition, the use of electric pumps will have savings realized from the gas not released. We estimate 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.

7.3.2.4 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.

7.3.3 Instrument Air System

7.3.3.1 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 electricity can install an instrument air system. A description of each of the components as described in the Natural Gas STAR document, "PRO Fact Sheet: Convert Gas Pneumatic Controls to Instrument Air":[95]

- 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

[93] See footnote 87.
[94] 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.
[95] See footnote 87.

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 CH_4 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.

7.3.3.2 Emission Reduction Potential and Effectiveness

Instrument air eliminates all emissions from natural gas-driven pumps, but can only be utilized in locations with sufficient and reliable electrical power. Furthermore, instrument air systems are more 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.[96] Because all emissions can be avoided by converting natural gas-driven chemical pumps to instrument air, CH_4 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, we estimate 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, we estimate

[96] 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.

that replacement of a pneumatic pump converted to instrument air will reduce CH_4 emissions can be reduced 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.

7.3.3.3 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.[97]

For natural gas processing, the cost of emissions reduction 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 we assume new processing plants will need to provide instrumentation of multiple control loops and size the instrument air system accordingly. As was discussed in the 2011 NSPS TSD, we assume 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 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 we have no data to characterize the number and types of gas-driven pumps at natural gas processing plants, we 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 emissions profiles between natural gas-driven diaphragm and piston pumps, we 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

[97] 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.

percent piston.). In our analysis, we 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. We then based or analysis on the use of 90 percent of available capacity of the system. We determined that there were basically three sizes (small, medium and large) compressors that would address the range of model plants. Table 7-6 summarizes the model plant analysis of required system capacity and potential emissions 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). We estimated costs, including operating costs, at three size levels; small, medium and large. Table 7-7 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. We estimate 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 $72 per year per piston pump.

7.2.3.4 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 7-6. 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)	Emissions 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 7-7 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 7-7. 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 ($2012)	Annualized Cost ($)	Labor Cost ($2008)	Power Cost ($2008)	Total O&M ($2008)	Total O&M ($2012)	Annual Cost ($)
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.

7.3.4 Install or Route Gas to Combustion Device

7.3.4.1 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 7-5. We estimate that capture and combustion device efficiency to be 95 percent reduction. Therefore, CH_4 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, we estimate 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. Likewise, for the transmission and storage segment, we estimate that routing emissions to a combustion device will reduce CH_4 reductions by 3.29 tons per year per diaphragm pump and 0.36 tons per year for a piston pump VOC emissions by 0.09 tons per year per diaphragm pump and 0.01 tons per year for a piston pump.

7.3.4.2 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.[98] Most processing plants or large dehydration facilities already have at least one existing combustion device.

7.3.4.3 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,[99] the capital cost for installing a new combustion device is $32,301 in 2008 dollars. We estimate 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, we estimate the annualized cost of installing a new combustion device to $21,877 using a 7 percent discount rate. We estimate the annualized cost of routing emissions to an existing combustion device to be $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.

[98] Ibid.
[99] U.S. EPA docket ID: EPA-HQ-OAR-2010-0505-0045.

7.3.4.4 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, CO_2, and CO. A summary of the estimated secondary emission are presented in Table 7-8. No other wastes should be created or wastewater generated.

Table 7-8. Secondary Impacts from Pneumatic Pumps Routed to a Combustion Device

Pump Type	(tpy)				
	THC[a]	CO[b]	CO_2[c]	NO_x[d]	PM[e]
Diaphragm	0.02	0.04	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.

7.3.5 Install or Route Gas to VRU

7.3.5.1 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, we estimate 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. We estimate that methane emissions 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, we estimate 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. Likewise, for the transmission and storage segment, we estimate that routing emissions to a VRU will reduce methane emissions by 3.29 tons per year for a diaphragm pump and 0.36 tons per year for a piston pump and VOC emissions by 0.09 tons per year per diaphragm pump and 0.01 tons per year per piston pump.

7.3.5.2 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 or large dehydration facilities.

7.3.5.3 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 vessels[100], the capital cost and installation costs for a VRU is estimated to be $98,186 in 2008 dollars. We estimate 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.

We estimate 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, we estimate 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.

7.3.5.4 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.

7.4 Regulatory Options

The affected facility definition for natural gas-driven pump is defined as a single natural gas-driven pump. Therefore, natural gas-driven pumps would be subject to a New Source Performance Standard (NSPS) at the time of installation.

The control technologies evaluated for natural gas-driven pumps included options that provided for 100 percent emissions 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. Also evaluated were gas recovery and gas combustion technologies that would result in 95 percent emissions reductions.

[100] Ibid.

The use of instrument air systems and electric pumps as a control alternative requires a consistent supply of electric power and use of solar-powered pumps and routing emissions to a VRU requires reliable supply of backup electrical power. Because reliable electric power is not considered to be universally available for production, gathering and boosting and transmission and storage locations these control technologies were 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.

Based on the costs and estimated emissions reductions for each of the viable emissions control alternatives, we further evaluated the cost per ton of emissions reduction 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 each pollutant separately. The second method, or the multipollutant approach, allocates costs among the pollutants that a given technology reduced (i.e., CH_4 and VOC). This multipollutant approach is based on estimates of the percentage reduction expected for each pollutant.

Based on the above considerations we evaluated the following regulatory alternatives

- Regulatory Option 1. Require a zero emission standard for natural gas processing plants.
- Regulatory Option 2. Require a 95 percent emissions reduction standard for production, gathering and boosting stations, transmission stations and storage facilities.
- Regulatory Option 3. Require a 95 percent emissions reduction standard for production, gathering and boosting stations, transmission stations and storage facilities only where an existing control device is available.

7.4.1 Evaluation of Regulatory Options

Regulatory Option 1 would require a zero emission of methane and VOC from gas-driven pumps at natural gas processing plants. To attain this emission reduction, the facility would need to either replace the natural gas-driven pumps with solar-powered or electric pumps or use instrument air systems to replace natural gas-driven function with air-driven function. We evaluated the cost of control for each of these options based on the estimated emissions reductions as detailed above.

Using the single-pollutant (allocate costs to each pollutant separately) for calculating cost of control, for the use of an instrument air system at natural gas processing plants we estimate the cost per ton of methane reduced to be between \$374 and \$2,185 and the cost per ton of VOC reduced was 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, we estimate 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, we 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. We estimate the cost of control for replacement of a natural gas-driven pump with either an electric pump or solar powered pumps to be between -$136 and $1,223 per ton of methane and between -$489 and $4,225 per ton of VOC, considering gas savings. We consider these costs to be reasonable. Based on these cost of control values for CH_4 and VOC, Regulatory Option 1 was accepted for the natural gas processing segment. Tables 7-9 through 7-12 summarize the cost of control for each of these options for the natural gas processing segment.

Because 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, 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 underground storage facilities. To attain this emission reduction, the facility could route emissions to a VRU or a combustion device.

Again we 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 per ton of methane and VOC reductions ranged from are $3,652 to over $1 million. The cost of control for a new combustion device was likewise unreasonable with the cost per ton of methane ranging between $3,328 to over $1 million. Based on these cost of control values for CH_4 and VOC, Regulatory Option 2 was rejected for all segments. Tables 7-13 through 7-16 summarize the cost of control for Option 2 for all segments.

Option 3 was evaluated to require 95 percent control of emissions in all segments only where an existing control device, capable of at least 95 percent reduction in emissions was available. The sole cost associated with this option that would be attributed to the emission reduction would be the cost of routing the pump emissions to the control device. As discussed above, we estimated that the cost to route emissions to either a VRU or a combustion device would be the same with a capital cost of approximately $2,000, which when annualized at a 7 percent discount rate, provided for an annualized cost of $285. Based on this annualized cost, using the multi-pollutant approach of calculating cost of control, the cost of control for methane reductions with a VRU or a combustion device ranged from $43 to $395 and the cost of control for VOC reductions ranged from $156 to $14,250. Considering natural gas savings when a VRU is used, the cost of control for methane emissions reductions is -$71 to $279 and the cost of control for VOC reductions ranged from -$254 to $1,004. We found these methane costs to be reasonable and Option 3 was accepted for control of natural gas-driven pump emissions all segments. Tables 7-17 through 7-18 summarize the cost of control.

Table 7-9. Cost of Control for Use of Instrument Air Systems at Natural Gas Processing Plants - Single-Pollutant

Plant Size	Compressor Cost[a]	Scenario[b]	Total Number of Pumps	Total Gas Saved[c] (Mcf)	Emissions 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 7-7 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 7-10. 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)	Emissions 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 7-7 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 7-11. Cost of Control for Replacement with Solar-Powered or Electric Pumps at Natural Gas Processing Plants - Single-pollutant

Type of Pump	Control Option	Emission Factor (tpy/pump)		Annualized Cost ($)	Natural Gas			Cost of Control ($/ton)			
								without savings		with savings	
		Methane	VOC		Emission Factor (scf/h)	Saved (Mcf/yr)	Value ($)	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)
Piston	Electric[a]	0.38	0.11	$4,175	2.48	22	$87	$1,452	$5,016	$1,223	$4,235
Piston	Solar	0.38	0.11	$2000	2.48	22	$87	$834	$2,882	$605	$2,091

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 7-12. 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)			
								without savings		with savings	
		Methane	VOC		Emission Factor (scf/h)	Saved (Mcf/yr)	Value ($)	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)
Piston	Electric[a]	0.38	0.11	$4,175	2.48	22	$87	$726	$2,508	$1,337	$2,112
Piston	Solar	0.38	0.11	$2,000	2.48	22	$87	$417	$1,1441	$720	$1,046

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 7-13. Cost of Control for Routing Gas-Driven Pump Emissions to a VRU - Single-pollutant Method

Pump Type/ Segment	Emission Reductions (tpy/pump)		Annualized Cost ($)	Natural Gas			Cost of Control ($/ton)			
							without savings		with savings	
	Methane	VOC		Emission Factor (scf/h)	Saved (Mcf/yr)	Value ($)	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	$7,531	$271,888
Storage	3.29	0.09	$24,755	22.45	187	$749	$7,531	$271,888	$7,531	$271,888
Piston Pumps										
Production	0.36	0.10	$24,755	2.48	21	$84	$68,574	$246,697	$68,343	$245,864
Processing	0.36	0.10	$24,755	2.48	21	$84	$68,574	$246,697	$68,343	$245,864
Transmission	0.36	0.01	$24,755	2.48	21	$84	$68,574	$2,475,608	$68,574	$2,475,608
Storage	0.36	0.01	$24,755	2.48	21	$84	$68,574	$2,475,608	$68,574	$2,475,608

Note: No gas savings is attributed to transmission and storage.

Table 7-14. Cost of Control for Routing Gas-Driven Pump Emissions to a VRU - Multi-Pollutant Method

Pump Type/ Segment	Emission Reductions (tpy/pump)		Annualized Cost ($)	Natural Gas			Cost of Control ($/ton)			
							without savings		with savings	
	Methane	VOC		Emission Factor (scf/h)	Saved (Mcf/yr)	Value ($)	Methane	VOC	Methane	VOC
Diaphragm Pumps										
Production	3.29	0.91	$24,755	22.45	187	$749	$3,766	$13,547	$3,254	$11,705
Processing	3.29	0.91	$24,755	22.45	187	$749	$3,766	$13,547	$3,254	$11,705
Transmission	3.29	0.09	$24,755	22.45	187	$749	$3,766	$135,944	$3,766	$135,944
Storage	3.29	0.09	$24,755	22.45	187	$749	$3,766	$135,944	$3,766	$135,944
Piston Pumps										
Production	0.36	0.10	$24,755	2.48	21	$84	$34,287	$123,348	$34,171	$122,932
Processing	0.36	0.10	$24,755	2.48	21	$84	$34,287	$123,348	$34,171	$122,932
Transmission	0.36	0.01	$24,755	2.48	21	$84	$34,287	$1,237,804	$34,287	$1,237,804
Storage	0.36	0.01	$24,755	2.48	21	$84	$34,287	$1,237,804	$34,287	$1,237,804

Note: No gas savings is attributed to transmission and storage.

Table 7-15. Estimated Cost of Control for Emission Reductions from Routing Gas-Drive Pump Emissions to a New Combustion Device - Single-Pollutant Method

Segment	Type of Pump	Emissions 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
Production	Piston	0.361	0.100	$21,877	$60,602	$218,017
Processing	Piston	0.361	0.100	$21,877	$60,602	$218,017
Transmission	Piston	0.361	0.010	$21,877	$60,602	$2,187,805
Storage	Piston	0.361	0.010	$21,877	$60,602	$2,187,805

Table 7-16. Estimated Cost of Control for Emission Reductions from Routing Gas-Drive Pump Emissions to a New Combustion Device - Multi-pollutant Method

Segment	Type of Pump	Individual Pneumatic Pump Emissions 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
Production	Piston	0.361	0.100	$21,877	$30,301	$109,009
Processing	Piston	0.361	0.100	$21,877	$30,301	$109,009
Transmission	Piston	0.361	0.010	$21,877	$30,301	$1,093,902
Storage	Piston	0.361	0.010	$21,877	$30,301	$1,093,902

Table 7-17. Cost of Control for Routing Gas-Driven Pump Emissions to an Existing Combustion Device or VRU - Single-pollutant Method

Pump Type/ Segment	Emission Reductions (tpy/pump)		Annualized Cost ($)	Natural Gas			Cost of Control ($/ton)			
				Emission Factor (scf/h)	Saved[a] (Mcf/yr)	Value ($)	without savings		with savings[a]	
	Methane	VOC					Methane	VOC	Methane	VOC
Diaphragm Pumps										
Production	3.29	0.91	$285	22.45	187	$749	$87	$312	($141)	($507)
Processing	3.29	0.91	$285	22.45	187	$749	$87	$312	($141)	($507)
Transmission	3.29	0.09	$285	22.45	187	$749	$87	$3,130	$87	$3,130
Storage	3.29	0.09	$285	22.45	187	$749	$87	$3,130	$87	$3,130
Piston Pumps										
Production	0.36	0.10	$285	2.48	21	$84	$789	$2,840	$558	$2,007
Processing	0.36	0.10	$285	2.48	21	$84	$789	$28,501	$558	$2,007
Transmission	0.36	0.01	$285	2.48	21	$84	$789	$28,501	$789	$28,501
Storage	0.36	0.01	$285	2.48	21	$84	$789	$28,501	$789	$28,501

a. Applies to VRU only. There is no gas savings with a combustion device.

Table 7-18. Cost of Control for Routing Gas-Driven Pump Emissions to an Existing Combustion Device or VRU - Multi-Pollutant Method

Pump Type/ Segment	Emission Reductions (tpy/pump)		Annualized Cost ($)	Natural Gas			Cost of Control ($/ton)			
							without savings		with savings[a]	
	Methane	VOC		Emission Factor (scf/h)	Saved[a] (Mcf/yr)	Value ($)	Methane	VOC	Methane	VOC
Diaphragm Pumps										
Production	3.29	0.91	$285	22.45	187	$749	$43	$156	($71)	($254)
Processing	3.29	0.91	$285	22.45	187	$749	$43	$156	($71)	($254)
Transmission	3.29	0.09	$285	22.45	187	$749	$43	$1,565	$43	$1,565
Storage	3.29	0.09	$285	22.45	187	$749	$43	$1,565	$43	$1,565
Piston Pumps										
Production	0.36	0.10	$285	2.48	21	$84	$395	$1,420	$279	$1,004
Processing	0.36	0.10	$285	2.48	21	$84	$395	$1,420	$279	$1,004
Transmission	0.36	0.01	$285	2.48	21	$84	$395	$14,250	$395	$14,250
Storage	0.36	0.01	$285	2.48	21	$84	$395	$14,250	$395	$14,250

a. Applies to VRU only. There is no gas savings with a combustion device.

7.4.2 Nationwide Impacts of Selected Regulatory Options

We calculated the nationwide impacts of the selected options by considering the estimated affected population for each of the target years, the estimated emissions 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, we estimate 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 emissions reductions and costs associated with Option 1.

For Option 3, we estimated that there will be no new pneumatic pumps installed in the transmission and storage segment in either of the projected years 2020 or 2025. Therefore we estimate there will be no nationwide emissions reductions or cost impacts for Option 3 for those segments.

We estimated that there will be 2,960 new or replaced pneumatic pumps installed in the production segment in the projected year 2020, with half of these pumps being diaphragm pumps and half being piston pumps. For the projected year 2025, we determined the affected population as those affected facilities from the years 2020 through and including 2025. Therefore, we estimate that 17,760 new pneumatic pumps will be installed in the production segment by 2025, half of which will be diaphragm pumps and half will be piston pumps.

Based on those activity numbers, the nationwide methane emission reductions in 2020 are estimated to be 4,865 tons per year of methane and 1,352 tons per year of VOC from diaphragm pumps and 534 tons per year of methane and 149 tons per year of VOC from piston pumps. The total nationwide emissions reductions, for the projected year 2020, are estimated to be 5,399 tons per year of methane and 1,501 tons per year of VOC. For the projected year 2025, we estimate the total nationwide emissions to be 32,395 tons per year of methane and 9,004 tons per year of VOC.

The nationwide cost is based only on the Option 3 costs related to routing pump emissions to a combustion device or a VRU. We estimated that the annualized cost for routing pump emissions either to a combustion device or a VRU would be $285. Based on the estimated population of 2,960 pneumatic pumps in 2020, we estimate the nationwide cost to be $843,600 in 2020. The nationwide costs are estimated to be $5,061,600 in 2025. Table 7-19 summarizes the nationwide impacts.

Table 7-19. Nationwide Impacts for Gas-Driven Pumps for Selected Regulatory Option

Regulatory Option	Number of Pumps Subject to NSPS	Annualized Cost ($)	Nationwide Emission Reductions (tpy)		Nationwide Costs (million $)
			Methane	VOC	
Projected Year 2020					
Option 1 Natural Gas Processing	0	$10,051 - $72,394	0	0	$0
Option 3 Production Transmission Storage	2,960 0 0	$285 0 0	5,399 0 0	1,501 0 0	$0.84 0 0
Projected Year 2025					
Option 1 Natural Gas Processing	0	$10,051 - $72,394	0	0	$0
Option 3 Production Transmission Storage	17,760 0 0	$285 0 0	32,395 0 0	9,004 0 0	$5.1 0 0

Secondary emissions impacts for Option 3 would include emissions resulting from the combustion of the recovered gas. Table 7-20 summarizes the nationwide secondary emissions for the projected year 2020 and 2025 for Option 3.

Table 7-20. Nationwide Secondary Impacts from Pneumatic Pumps Routed to a Combustion Device

Segment	(tpy)				
	THC[a]	CO[b]	CO_2[c]	NO_x[d]	PM[e]
Projected Year 2020					
Production	25	66	23,616	12	0
Projected Year 2025					
Production	150	396	141,696	72	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.

8.0 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. This chapter discusses the air pollutant emissions from these compressors 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 pollutant 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.

8.1 Process Description

8.1.1 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.

8.1.2 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 groves 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.

8.2 Emissions Data and Emissions Factors

8.2.1 Summary of Major Studies and Emissions Factors

There are a few studies that have been conducted that provide leak estimates from reciprocating and centrifugal compressors. These studies are provided in Table 8-1, along with the type of information contained in the study.

Table 8-1. Major Studies Reviewed for Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Information	Emissions Information	Control Information
Inventory of U.S. GHG Emissions and Sinks: 1990-2012[a]	EPA	2014	Nationwide	X	
GHG Mandatory Reporting Rule and TSD[b]	EPA	2013	Nationwide	X	
Inventory of GHG Emissions and Sinks: 1990-2012[c]	EPA	2014	Nationwide/ Regional	X	
CH_4 Emissions from the Natural Gas Industry[d]	GRI/EPA	1996	Nationwide	X	
Natural Gas STAR Program[e,f]	EPA	1993-2010	Nationwide	X	X
Natural Gas Industry CH_4 Emission Factor Improvement Study[g]	URS Corporation, UT Austin, and U.S. EPA	2011	None	Emission Factors Only	
Characterizing Pivotal Sources of CH_4 Emissions from Natural Gas Production: Summary and Analysis of API and ANGA Survey Responses[h, i]	API/ANGA	2012	Regional	X[h]	
Economic Analysis of CH_4 Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries[j]	ICF International (Prepared for the Environmental Defense Fund)	2014	Regional	X	X

a. U.S. EPA. GHG Inventory: Emission and Sinks 1990-2012. 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. U.S. EPA. Methodology for Estimating CH_4 and CO_2 Emissions from Natural Gas Systems. GHG Inventory: Emission and Sinks 1990-2008. Washington, DC. and U.S EPA. Methodology for Estimating CH_4 and CO_2 Emissions from Petroleum

Systems. GHG Inventory: Emission and Sinks 1990-2008. Washington, DC.
d. 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.
e. U.S. EPA. Lessons Learned: Reducing Methane Emissions from Compressor Rod Packing Systems. Natural Gas STAR. EPA. 2006.
f. U.S. EPA. Lessons Learned: Replacing Wet Seals with Dry Seals In Centrifugal Compressors. *Natural Gas STAR. EPA.* 2006.
g. 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.
h. 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.
i. The API/ANGA study provided information on equipment counts that could augment nationwide emissions calculations. No source emissions information was included.
j. 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.

8.2.2 Representative Reciprocating and Centrifugal Compressor Emissions

The methodology for estimating emission from reciprocating compressor rod packing was to use the CH_4 emission factors referenced in the EPA/GRI study[101] and the CH_4-to-VOC ratio developed in the gas composition memorandum.[102] 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 CH_4 emission rate was converted to a mass emission rate using a density of 41.63 lbs of CH_4 per Mcf. This conversion factor was developed assuming that CH_4 is an ideal gas and using the ideal gas law to calculate the density. A summary of the CH_4 emission factors is presented in Table 8-2. Once the CH_4 emissions were calculated, the ratio of VOC to CH_4 was used to estimate VOC emissions. The specific VOC-to-CH4 ratios used for this analysis were 0.278 lbs VOC per pound of CH_4 for the production and processing segments, and 0.0277 lbs VOC per pound of CH_4 for the transmission and storage segment. A summary of the reciprocating compressor emissions are presented in Table 8-3.

The compressor emission factors for wet seals and dry seals are based on data used in the GHG Inventory[103]. The wet seals CH_4 emission factor was calculated based on a sampling of 48 wet seal centrifugal compressors. The dry seal CH_4 emission factor was based on data collected by the Natural Gas STAR Program. The CH_4 emissions were converted to VOC and HAP emissions using the same gas composition ratios that were used for reciprocating engines.[104]

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[101] 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.
[102] See footnote 6.
[103] U.S. EPA. Methodology for Estimating CH_4 and CO_2 Emissions from Petroleum Systems. GHG Inventory: Emission and Sinks: 1990-2012. Washington, DC. 2014.
[104] Ibid

Since publication of the white paper, additional data have become available on compressor emissions in transmission and storage, including reporting year 2013 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 2,247,626 tons CO_2e of methane, and reported emissions from centrifugal compressors are 597,715 tons CO_2e 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 GHG Inventory, and found that the GHG Inventory had higher average emissions.

Table 8-2. Methane Emission Factors for Reciprocating and Centrifugal Compressors

Compressor Station	Reciprocating Compressors			Centrifugal Compressors		
	CH_4 Emission Factor (scf/hr-cylinder)	Average Number of Cylinders	Pressurized Factor[a]	Wet Seal CH_4 Emission Factor (scf/minute)	Dry Seals CH_4 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 CH_4 and CO_2 Emissions from Petroleum Systems. GHG Inventory: Emission and Sinks: 1990-2012. Washington, DC. 2014. Annex 3.5 Table A-129.

Table 8-3. Baseline Emission Estimates for Reciprocating and Centrifugal Compressors

Compressor Location	Baseline Emission Estimates (tpy)	
	CH_4	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

8.3 Nationwide Emissions from New Sources

8.3.1 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.[105] 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 8-3. A summary of the number of new reciprocating and centrifugal compressors for each of the oil and natural gas segments is presented in Table 8-4.

8.3.2 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. An average was taken of only the years with an increase in compressors and rounded to the nearest whole number. The results of this analysis are shown in Table 8-4.

[105] See footnote 6.

Table 8-4. 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	24	0	2
Storage	43	1	5

a. Estimates of the number of new compressors were rounded to the nearest whole number.

8.3.3 Emission Estimates

Nationwide baseline emission estimates for new reciprocating and centrifugal compressors are summarized in Table 8-5 by industry segment.

Table 8-5. Nationwide Baseline Emissions for New Reciprocating and Centrifugal Compressors

Compressor Location/Compressor Type	Nationwide Baseline Emissions (tpy)	
	CH_4	VOC
Transmission		
Reciprocating Compressors	651	18
Wet Seal Centrifugal Compressors	0	0
Dry Seal Centrifugal Compressors	39.4	1.09
Storage		
Reciprocating Compressors	1,215	33.6
Wet Seal Centrifugal Compressors	117	3.24
Dry Seal Centrifugal Compressors	73.5	2.04

8.4 Control Techniques

8.4.1 Potential Control Techniques

The potential control options reviewed for reducing emissions from reciprocating compressors include control techniques that limit the leaking of natural gas past the piston rod packing. This includes replacement of the compressor rod packing, replacement of the piston rod, and the refitting or realignment 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 past 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 CH_4 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.[106] 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. Also, upgrading piston rods by coating them with tungsten carbide or chrome reduces wear over the life of the rod. This analysis assumes operators will choose, at their discretion, when to replace the rod and hence, does not consider this control technique to be a practical control option for reciprocating compressors. 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 reasonable 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-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)

[106] U.S. EPA. Lessons Learned: Reducing Methane Emissions from Compressor Rod Packing Systems. Natural Gas STAR. Washington DC. 2006.

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.

8.4.2 Reciprocating Compressor Rod Packing Replacement

8.4.2.1 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 packing rings ensures the correct fit is maintained between packing rings and the rod.

8.4.2.2 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 segment 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 8-2) 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

$$R_{PTS} = \frac{Comp_{New}^{PTS}\left(E_{G\&B} - E_{New}\right) \times C \times O \times 8760}{10^6}$$

where:

R_{PTS} = Potential CH_4 emission reductions from transmission or storage compressors switching from wet seals to dry seals, 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 8-2, 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 cylinder[107] for this analysis.

C = Average number of cylinders for transmission or storage compressors in Table 8-2.

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.

[107] Ibid.

A summary of the potential emission reductions for reciprocating compressor rod packing replacement in the transmission and storage segment is presented in Table 8-6. The emissions of VOC were estimated using the CH_4 emissions calculated above and the CH_4-to-VOC- ratio developed for each of the segments in the gas composition analysis conducted for the NSPS.[108]

Table 8-6. Estimated Annual Reciprocating Compressor Emission Reductions from Replacing Rod Packing

Compressor Location	Number of New Sources Per Year	Individual Compressor Emission Reductions (tons/compressor-year)		Nationwide Emission Reductions (tpy)	
		CH_4	VOC	CH_4	VOC
Transmission	24	21.7	0.600	520	14.4
Storage	43	21.8	0.604	939	26.

8.4.2.3 Cost Impacts

Costs for the replacement of reciprocating compressor rod packing were obtained from a Natural Gas STAR Lessons Learned document[109] which estimated the cost to replace the 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.[110] The cost impacts are based on the replacement of the rod packing 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

[108] See footnote 5.
[109] See footnote 101.
[110] Ibid.

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 8-2. 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 8-2. 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., CH4 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 8-7.

There is 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 8-7. Cost of Control for Reciprocating Compressor Rod Packing Replacement ($2012)

Compressor Location	Capital Cost ($)	Annual Cost ($/yr)	Cost of Control Single-Pollutant ($/ton)		Cost of Control Multi-Pollutant Method ($/ton)	
			CH_4	VOC	CH_4	VOC
Transmission	$5,650	$1,748	$81	$2,910	$40	$1,455
Storage	$7,705	$2,077	$95	$3,434	$48	$1,717

8.4.2.4 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.

8.4.3 Centrifugal Compressor Dry Seals

8.4.3.1 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 benefits of dry seals include:

- Gas Leak Rates. During normal operation, dry seals leak at a rate of 6 scfm CH_4 per compressor.[111] 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 CH_4 per compressor.[112, 113]
- 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

[111] 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.

[112] "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

[113] See footnote 6.

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.

8.4.3.2 Emissions Reduction Potential

The emissions reductions of the dry seal compressors 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 8-2 were used in combination with an operating factor of 30 percent for transmission centrifugal compressors and 22.4 percent for storage centrifugal 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.[114] 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.[115] A summary of the emission reduction from the replacement of wet seals with dry seals is shown in Table 8-8.

Table 8-8. 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)	
		CH_4	VOC	CH_4	VOC
Transmission	0	137	3.79	0	0
Storage	1	102	2.83	102	2.83

8.4.3.3 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. 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

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[114] See footnote 6.

[115] U.S. EPA. Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors. Natural Gas STAR. 2006.

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 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., CH4 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 8-9 along with the CH_4 and VOC cost of control for the dry seal compressor option. There is no gas savings cost benefits 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 8-9. Cost of Reductions for Centrifugal Compressor Using Dry Seal Compressors ($2012)

Compressor Location	Capital Cost ($)	Annual Cost Per Compressor ($/compressor-year)		CH_4 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

8.4.3.4 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.

8.4.4 Centrifugal Compressor Wet Seals Routed to a Combustion Device

8.4.4.1 Description

Another control option used to reduce pollutant 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 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 other process.

8.4.4.2 Emissions Reduction Potential

Combustion devices have been used in the oil and natural gas industry to combust gas streams that have VOC and 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 CH_4, VOC, and HAP. The wet seal emissions in Table 8-5 were used along with the control efficiency to calculate the emissions reductions from this option. A summary of the emission reductions is presented in Table 8-10.

Table 8-10. 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)	
		CH_4	VOC	CH_4	VOC
Transmission	0	149	4.12	0	0
Storage	1	111	3.08	111	3.08

8.4.4.3 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.[116] The heat content of the gas stream was calculated using information from the gas composition memorandum.[117] A summary of the capital and annual costs for wet seals routed to a flare is presented in Table 8-11. 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., CH4 and VOC). This allocation was based on estimates of the percentage reduction expected for each pollutant. The CH_4 and VOC cost of control for the wet seals routed to a combustion device option is also shown in Table 8-11. There is no cost savings estimated for this option because the recovered gas is combusted.

Table 8-11. 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	CH_4	VOC	CH_4	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

[116] EPA Air Pollution Control Cost Manual - Sixth Edition, (EPA 452/B-02-001).
[117] See footnote 5.

8.4.4.4 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, CO_2, and CO emissions. A summary of the estimated secondary emission are presented in Table 8-12. No other wastes should be created or wastewater generated

Table 8-12. 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	1.54	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.

8.5 Regulatory Options

Subpart OOOO defines a reciprocating compressor is defined as a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft. A centrifugal compressor is defined as a piece of equipment that compresses a process gas by means of mechanical rotating vanes or impellers. Therefore these types of compressors would be subject to the NSPS at the time of installation. The following Regulatory options were evaluated:

- 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.

8.5.1 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 8.4.1. The CH_4 and VOC cost of control for reciprocating compressors at transmission stations is $81 and $2,910 per ton, respectively. The CH_4 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 CH_4, Regulatory Option 1 was accepted 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 8.4.2, 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. The CH_4 and VOC cost of emissions reductions for dry seals compressors was calculated to be $55/ton and $1,974/ton respectively for centrifugal compressors located at transmission facilities, not including the savings from operation and maintenance costs. When those savings were considered the CH_4 and VOC cost of control was calculated to be -$627/ton and -$22,642/ton. The CH_4 and VOC cost of control for dry seal compressors was calculated to be $73/ton and $2,643/ton respectively for centrifugal compressors located at storage facilities, not including the savings from operation and maintenance costs. When those savings were considered the CH_4 and VOC cost of control was calculated to be -$840/ton and -$30,324/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, Regulatory Option 2 was rejected 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 another useful process. The CH_4 and VOC cost of control for routing emissions from a wet seal system to a combustion device was calculated to be $767/ton and $27,705/ton respectively for centrifugal compressors located at transmission facilities. The CH_4 and VOC cost of control for routing emissions from a wet seal system to a combustion device was calculated to be $1,028/ton and $37,105/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. For those facilities the CH_4 and VOC cost of control were calculated to be $22/ton and $804/ton respectively for transmission facilities and $30/ton and $1,076/ton respectively for storage facilities. Based on these cost of control values, Regulatory Option 3 was accepted for the transmission and storage segment.

8.5.2 Nationwide Impacts of Selected Regulatory Options

Tables 8-13 and 8-14 summarize the impacts of the selected regulatory options by industry segment. Regulatory Option 1 is estimated to affect 24 reciprocating compressors at transmission facilities and 43 reciprocating compressors at underground storage facilities I 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 2025 is calculated as all compressors affected from 2020 through 2025. A summary of the capital and annual costs and emission reductions for this option is presented in Table 8-13.

Regulatory Option 2 is expected to affect 1 new wet-seal centrifugal compressor in the transmission and storage segment (specifically at a storage facility). 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. A summary of the capital and annual costs and emission reductions for this option is presented in Table 8-14. A summary of the nationwide secondary combustion-related emissions from Option 2 are summarized in Table 8-15.

Table 8-13. Nationwide Cost Impacts for Regulatory Option 1

Compressor Location	Number of New Sources Per Year	Nationwide Emission Reductions (tpy)		Total Nationwide Costs	
		CH_4	VOC	Capital Cost ($)	Annualized Cost ($/year)
Base Year 2012 and Projected Year 2020					
Transmission	24	520	14.4	$135,606	$41,941
Storage	43	939	26	$331,310	$89,301
Projected Year 2025					
Transmission	144	3,122	87	$813,636	$251,646
Storage	258	5,634	156	$1,987,860	$535,803

Table 8-14. Nationwide Cost Impacts for Regulatory Option 3

Compressor Location	Number of New Sources Per Year	Nationwide Emission Reductions (tpy)		Nationwide Costs			
		CH_4	VOC	Capital Cost New CD[a] ($)	Capital Cost Existing CD[b] ($)	Annual Cost New CD[a] ($/year)	Annual Cost Existing CD[b] ($/year)
Base Year 2012 and Projected Year 2020							
Transmission	0	0	0	$0	$0	$0	$0
Storage	1	111	3	71,783	$23,252	$114,146	$3,311
Projected Year 2025							
Transmission	0	0	0	$0	$0	$0	$0
Storage	6	666	19	$430,697	$139,512.28	$684,874	$19,863

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 8-15. Nationwide Secondary Impacts from Compressor Emissions Routed to a Combustion Device

Compressor Location	(tpy)				
	THC[a]	CO[b]	CO_2[c]	NO_x[d]	PM[e]
Projected Year 2020					
Storage	0.58	1.54	550	0.28	0.01
Projected Year 2025					
Production	3.48	9.24	3,300	1.68	0.06

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.

9.0 OTHER POTENTIAL IMPACTS

The following sections describe impacts potentially realized as a result of the implementation of regulatory options discussed in the sections above. Specifically, many of the options discussed have potential to realize natural gas savings based on the capture of natural gas that would have otherwise been emitted or combusted. This natural gas savings can result in monetary savings to the owner or operator which can offset costs incurred by control requirements. Although the NSPS does not directly regulate HAP, HAP emission are reduced as a result of the reductions in the emissions of natural gas. Finally, since CH_4 is known to contribute to global warming, reducing CH_4 emissions has the net effect of reducing contribution of the oil and gas industry to global warming. Consistent with the GHG Inventory, the global warming potential is discussed here as CO_2e of CH_4.

9.1 Natural Gas Savings

A potential benefit of emissions reductions for the affected facilities under the NSPS is the gas savings realized in the process of capturing gas that would have otherwise been vented or combusted. 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 we estimated that 899 Mcf of natural gas is recovered during the average 3-day completion event.
- For equipment leaks, the semiannual frequency of implementation of an OGI monitoring plan and repair of leaks found we estimate that the average annual gas saved would be 38 Mcf for oil wells, 158 Mcf for gas wells, 1,222 Mcf for gathering and boosting stations, 1,937 Mcf for transmission stations, and 5,107 for storage facilities.
- For pneumatic controllers, we estimate the use of low-bleed controllers instead of high-bleed controllers will save 147 Mcf of natural gas per year.
- For reciprocating compressors, we 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.[118]
- For centrifugal compressors, we estimate that the replacement of one wet seal compressor with a dry seal compressor will save 5,290 Mcf per year.[119]

[118] See footnote 4.
[119] See footnote 4.

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, we calculated the nationwide gas savings for each of the regulatory options discussed in the sections above for the projected years 2020 and 2025. Table 9-1 presents the gas savings we estimate for these affected facilities.

Table 9-1. 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			
Well Completions			
Development Oil Wells	6,903	6,206	$24.8
Equipment Leaks			
Oil Well Site	16,562	629	$2.5
Gas Well Site	5,518	872	$3.5
Gathering	259	316	$1.3
Transmission	6	12	$0.0
Storage	15	77	$0.3
Pneumatic Controllers	210	66,060	$0.3
Pneumatic Pumps	2,960	31	$0.1
Reciprocating Compressors - Transmission	24	0	0.0
Reciprocating Compressors - Storage	43	27	$0.11
Centrifugal Compressors - Storage	1	49	$0.19
Total Projected Year 2020	32,501	8,224	$33
Projected Year 2025			
Well Completions			
Development Oil Wells	9,133	6,301,770	$25
Equipment Leaks			
Oil Well Site	100,175	3,807	$15.2
Gas Well Site	38,933	6,151	$24.6
Gathering	1,554	1,899	$7.6
Transmission	36	70	$0.3
Storage	90	460	$1.8
Pneumatic Controllers	1,259	186	$0.7
Pneumatic Pumps	17,760	0	0.0
Reciprocating Compressors - Transmission	144	161,630	$0.65
Reciprocating Compressors - Storage	258	289,587	$1.10
Centrifugal Compressors - Storage	6	32	$0.13
Total Projected Year 2025	167,117	470,026	$77

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).

9.2 Reductions of HAP and CO_2e

A potential benefit of emissions reductions for the affected facilities under the NSPS is the reduction of HAP as a result of reduction of the gas that contains HAP. For the purposes of the NSPS, we estimate HAP emissions by applying a ratio to the CH_4 emissions. The ratio used is based on gas composition analysis conducted for the NSPS.[120] Because gas composition was determined to vary between industry segments and between the various affected facilities, different rations were used accordingly. Table 9-2 summarizes that HAP-to-CH_4 ratios used for the various affected facilities in the various segments.

Table 9-2. HAP-to-CH_4 Ratios Used to Estimate HAP Emissions

Segment	Affected Facility	HAP-to-CH_4 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
	Pneumatic Pumps	0.0105
Transmission	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

Based on the CH_4 emissions reductions estimated in the above sections for the respective affected facilities and regulatory options, we estimated the HAP emissions. Table 9-3 summarizes the HAP emissions calculated for each affected facility and regulatory option.

Because CH_4 is of concern for global warming effects, we also calculated the global warming potential expressed as CO_2e for the CH_4 reductions from the proposed regulatory options. For the purposes of this analysis, one ton of CH_4 is equal to 25 tons of CO_2e. We have converted the CO_2e values to metric tonnes consistent with the presentation of CO_2e in the GHG Inventory. Table 9-3 summarizes the global warming potential calculated for the proposed regulatory options.

[120] See footnote 5.

Table 9-3. HAP and CO_2e Reductions for Selected Regulatory Options

Affected Facility	Number of Sources Subject to NSPS	Nationwide Emission Reductions			
		CH_4 (tpy)	VOC (tpy)	HAP (tpy)	CO_2e (MT/year)
Projected Year 2020					
HF Oil Well Completions					
All Oil Wells	14,677	135,516	113,481	13.6	3,073,453
Development Oil Wells	13,806	127,479	106,751	12.7	2,891,169
Exploratory/Delineation Oil Wells	870	8,037	6,730	0.8	182,285
Equipment Leaks					
Oil Well Site	16,562	10,807	3,004	113.5	245,099
Gas Well Site	5,518	15,029	4,178	157.8	340,852
Gathering & Boosting	259	5,461	1,518	57.3	123,853
Transmission	6	225	6	0.2	5,103
Storage	15	1,480	27	1.2	33,566
Pneumatic Controllers	210	1,248	35	1.0	28,304
Pneumatic Pumps	2,960	5,399	1,501	4.4	122,447
Reciprocating Compressors					
Transmission	24	520	14.4	0.4	11,802
Storage	43	939	26	0.8	21,294
Centrifugal Compressors -Storage	1	102	2.8	0.08	2,318
Total Projected Year 2020	40,275	176,063	123,774	350	3,993,050
Projected Year 2025					
HF Oil Well Completions					
All Oil Wells	14,970	138,221	115,747	13.8	3,134,810
Development Oil Wells	13,803	127,452	106728	12.7	2,890,554
Exploratory/Delineation Oil Wells	1,166	10,770	9,019	1.1	244,256
Equipment Leaks					
Oil Well Site	100,175	65,365	18,170	686.3	1,482,453
Gas Well Site	38,933	106,036	29,475	1113.4	2,404,856
Gathering	1,554	32,767	9,108	344.1	743,143
Transmission	36	1,347	37	1.1	30,549
Storage	90	8,879	246	7.3	201,372

Affected Facility	**Number of Sources Subject to NSPS**	**Nationwide Emission Reductions**			
		CH_4 (tpy)	**VOC (tpy)**	**HAP (tpy)**	**CO_2e (MT/year)**
Pneumatic Controllers	1,260	7,488	210	6.2	169,825
Pneumatic Pumps	17,760	32,395	9,004	26.6	734,706
Reciprocating Compressors					
Transmission	144	3,122	87	2.5	70,811
Storage	42	5,634	156	4.5	127,766
Centrifugal Compressors					
Storage	6	613	17	0.5	13,907
Total Projected Year 2025	174,970	397,890	182,144	2,203	9,024,004