United States Environmental Protection Agency

Control Techniques Guidelines for the Oil and Natural Gas Industry

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Control Techniques Guidelines for the Oil and Natural Gas Industry

U.S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

ACRONYMS AND ABBREVIATIONS

Acronyms/Abbreviations	Description
ACA	Air Compliance Advisor
ANGA	America's Natural Gas Alliance
APCD	Air Pollution Control District
API	American Petroleum Institute
AQMD	Air Quality Management District
ARCADIS	a global consulting firm
bbl/day	barrels per day
boe/day	barrels of oil equivalent per day
BSER	best system of emission reduction
BTEX	benzene, toluene, ethylbenzene and xylenes
Btu	British thermal unit
Btu/scf	British thermal unit per standard cubic feet
CAA	Clean Air Act
CETAC-WEST	Canadian Environmental Technology Advancement Corporation-WEST
Cfm	cubic foot per minute
CFR	Code of Federal Regulations
CH4	methane
CMSA	Consolidated Metropolitan Statistical Area
CO	carbon monoxide
CO_2	carbon dioxide
CTG	Control Techniques Guidelines
E&P Tanks Program	is a personal computer-based software designed to use site-specific information to predict emission from petroleum production storage tanks
ERG	Eastern Research Group
EVRU	ejector vapor recovery units
FIP	Federal Implementation Plan
FR	Federal Register
FRED	Federal Reserve Economic Data
G	Gram
GDP	gross domestic product
GHG	greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
GRI	Gas Research Institute
HAP	hazardous air pollutants

Acronyms/Abbreviations	Description
HPDI database	provides production data and web-enabled analytical software tools for a wide range of oil and gas related customers
H_2S	hydrogen sulfide
ICF International	a firm that provides professional services and technology solutions in strategy and policy analysis, program management, project evaluation, and other services
IR	infrared
kg/hr/comp	kilogram per hour per component
kg/hr/source	kilogram per hour per source
kPa	kilopascals
kW	kilowatt
LAER	lowest achievable emission rate
LDAR	leak detection and repair
Mcf	thousand cubic feet
MMcf/yr	million cubic feet per year
NA	Nonattainment
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGL	natural gas liquids
NOx	nitrogen oxide
NSPS	New Source Performance Standards
O&M	operation & maintenance
OAQPS	Office of Air Quality Planning and Standards
OCCM	OAQPS Control Cost Manual
OEL	open-ended lines
OGI	optical gas imaging
OTR	Ozone Transport Region
OVA	organic vapor analyzer
PG&E	Pacific Gas & Electric
PNAS	Proceedings of the National Academy of Sciences
ppm	parts per million
Ppmv	parts per million by volume
PRV	pressure relief valve
Psi	pounds per square inch
Psia	pounds per square inch absolute
Psig	pounds per square inch gauge
PTE	potential to emit
RACT	reasonably available control technology
RBLC	RACT/BACT/LAER Clearinghouse
Scf	standard cubic feet
Scfh	standard cubic feet per hour

Acronyms/Abbreviations	Description
scfh-cylinder	standard cubic feet per hour-cylinder
Scfm	standard cubic feet per minute
SIP	State Implementation Plan
SO_2	sulfur dioxide
STSD	supplemental technical support document
THC	total hydrocarbons
TOC	total organic compounds
Tpy	tons per year
TSD	technical support document
TVA	toxic vapor analyzer
U.S.	United States
U.S. EIA	U.S. Energy Information Administration
U.S. EPA	U.S. Environmental Protection Agency
VOC	volatile organic compound
VRU	vapor recovery unit

1.0 INTRODUCTION

Section 172(c)(1) of the Clean Air Act (CAA) provides that state implementation plans (SIPs) for nonattainment areas must include “reasonably available control measures” including “reasonably available control technology” (RACT), for existing sources of emissions. CAA Section 182(b)(2)(A) provides that for Moderate ozone nonattainment areas, states must revise their SIPs to include RACT for each category of volatile organic compound (VOC) sources covered by control techniques guidelines (CTG) documents issued between November 15, 1990, and the date of attainment. Section 182(c) through (e) applies this requirement to states with ozone nonattainment areas classified as Serious, Severe, and Extreme. CAA Section 184(b) requires that states in ozone transport regions must revise their SIPs to implement RACT with respect to all sources of VOC in the state covered by a CTG issued before or after November 15, 1990. CAA Section 184(a) establishes a single Ozone Transport Region (OTR) comprised of the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont and the Consolidated Metropolitan Statistical Area (CMSA) that includes the District of Columbia.

The U.S. Environmental Protection Agency (EPA) defines RACT as “the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.” 44 FR 53761 (September 17, 1979).

This CTG provides recommendations to inform state, local, and tribal air agencies (hereafter, collectively referred to as air agencies) as to what constitutes RACT for select oil and natural gas industry emission sources. Air agencies can use the recommendations in the CTG to inform their own determination as to what constitutes RACT for VOC for the emission sources presented in this document in their Moderate or higher ozone nonattainment area or state in the OTR. The information contained in this document is provided only as guidance. This guidance does not change, or substitute for, requirements specified in applicable sections of the CAA or the EPA’s regulations; nor is it a regulation itself. This document does not impose any requirements on facilities in the oil and natural gas industry. It provides only recommendations for air agencies to consider in determining RACT. Air agencies may implement other technically-sound approaches that are consistent with the CAA, the EPA's implementing regulations, and policies on interpreting RACT.

The recommendations contained in this CTG are based on data and information currently available to the EPA. The EPA evaluated the sources of VOC emissions in the oil and natural gas industry and the available control approaches for addressing these emissions, including the costs of such approaches. The recommendations contained in this CTG may not be appropriate for every situation based upon the circumstances of a specific source (e.g., VOC content of the gas, safety concerns/reasons). Regardless of whether an air agency chooses to adopt rules implementing the recommendations contained herein, or to issue rules that adopt different approaches for RACT for VOC from oil and natural gas industry sources, air agencies must submit their RACT rules to the EPA for review and approval using the SIP process. The EPA will evaluate the RACT determinations and determine, through notice and comment rulemaking, whether these determinations in the submitted rules meet the RACT requirements of the CAA and the EPA's regulations. To the extent an air agency adopts any of the recommendations in this guidance into its RACT rules, interested parties can raise questions and objections about the appropriateness of the application of this guidance to a particular situation during the development of these rules and the EPA's SIP process. Such questions and objections can relate to the substance of this guidance.

Section 182(b)(2) of the CAA requires that a CTG document issued between November 15, 1990, and the date of attainment include the date by which states subject to CAA section 182(b) must submit SIP revisions. Accordingly, the EPA is setting forth a 2-year period, from the date of publication of the notice of availability of this CTG in the *Federal Register* for the required SIP submittal.

2.0 BACKGROUND AND OVERVIEW

There have been several federal and state actions to reduce VOC emissions from certain emission sources in the oil and natural gas industry. A summary of these actions is provided below.

2.1 History of New Source Performance Standards that Regulate Emission Sources in the Oil and Natural Gas Industry

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). Since the 1979 listing, the EPA has promulgated performance standards to regulate VOC emissions from production, processing, transmission, and storage as well as sulfur dioxide (SO_2) emissions from natural gas processing emission sources and, more recently, greenhouse gases (GHG). On June 24, 1985 (50 FR 26122), the EPA promulgated an NSPS for natural gas processing plants that addressed VOC emissions from leaking components (40 CFR part 60, subpart KKK). On October 1, 1985 (50 FR 40158), a second NSPS was promulgated for natural gas processing plants that regulated SO_2 emissions (40 CFR part 60, subpart LLL). On August 16, 2012 (77 FR 49490) (2012 NSPS), the EPA finalized its review of NSPS standards for the listed oil and natural gas source category and revised the NSPS for VOC from leaking components at natural gas processing plants, and the NSPS for SO_2 emissions from natural gas processing plants. At that time, the EPA also established standards for certain oil and natural gas emission sources not covered by the existing standards. In addition to the emission sources that were covered previously, the EPA established new standards to regulate VOC emissions from hydraulically fractured gas wells, centrifugal compressors, reciprocating compressors, pneumatic controllers, and storage vessels. In 2013 (78 FR 58416) (2013 NSPS Reconsideration) and 2014 (79 FR 79018), the EPA amended the standards set in 2012 in order to improve implementation of the standards. In 2016 (81 FR 35824, June 3, 2016), the EPA finalized new standards to regulate GHG and VOC emissions across the oil and natural gas source category. Specifically, the EPA finalized both GHG standards (in the form of limitations on methane emissions) and VOC standards for several emission sources not previously covered by the NSPS (i.e., hydraulically fractured oil well completions, pneumatic pumps, and fugitive emissions from well sites and compressor stations).

In addition, the EPA finalized GHG standards for certain emission sources that were regulated for only VOC (i.e., hydraulically fractured gas well completions, centrifugal compressors, reciprocating compressors, pneumatic controllers and equipment leaks at natural gas processing plants). With respect to certain equipment that are used across the industry, 40 CFR part 60 subpart OOOO regulates only a subset of these equipment (pneumatic controllers, centrifugal compressors, reciprocating compressors). The final amendments established GHG standards (40 CFR part 60 subpart OOOOa) for these equipment and extended the current VOC standards to previously unregulated equipment. Although not regulated under the oil and natural gas NSPS, stationary reciprocating internal combustion engines and combustion turbines used in the oil and natural gas industry are covered under separate NSPS specific to engines and turbines (40 CFR part 60, subparts IIII, JJJJ, GG, KKKK).

In addition to NSPS issued to regulate VOC emissions from the oil and gas industry, the EPA also published a CTG document that recommended the control of VOC emissions from equipment leaks from natural gas processing plants in 1983 (1983 CTG; 49 FR 4432; February 6, 1984).[1] This 2016 CTG is the only CTG document issued since 1983 for the oil and natural gas industry.

2.2 State and Local Regulations

Several states regulate VOC emissions from storage vessels in the oil and natural gas industry. There are also a few states (e.g., Colorado, Wyoming, and Montana) that have established specific permitting requirements or regulations that control VOC emissions from emission sources in the oil and natural gas industry (e.g., compressors, pneumatics, fugitive emission components):

(1) The Colorado Department of Public Health and Environment, Air Quality Control Commission has developed emission regulations 3, 6, and 7 that apply to oil and natural gas industry emission sources in Colorado. (https://www.colorado.gov/pacific/cdphe/summary-oil-and-gas-emissions-requirements.)

(2) Montana requires oil and gas well facilities to control emissions from the time the well is completed until the source is registered or permitted (Registration of Air Contaminant

[1] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC, 27711. *Guideline Series. Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants.* December 1983. EPA-450/3-83-007.

Sources Rule, Rule 17.8.1711, Oil or Gas Well Facilities Emission Control Requirements). (http://www.mtrules.org/gateway/ruleno.asp?RN=17%2E8%2E1711.)

(3) The Wyoming Department of Environmental Quality limits VOC emissions from existing sources in ozone nonattainment areas and has issued specific permitting guidance that apply to oil and natural gas facilities. (Chapter 6, Section 2 Permitting Guidance, last revised in September 2013).

(4) The San Joaquin Valley Air Pollution Control District requires control of VOC emissions from several VOC oil and natural gas emission sources, including, but not limited to, (a) storage vessels, (b) crude oil production sumps, (c) components at light crude oil production facilities, natural gas production facilities and natural gas processing facilities, and (d) in-situ combustion well vents.

In some states, general permits have been developed for oil and natural gas facilities.

General permits are permits where all the terms and conditions of the permit are developed for a given industry and authorize the construction, modification, and/or operation of facilities that meet those terms and conditions. For example, West Virginia, Ohio, and Pennsylvania have developed General Air Permits for the oil and natural gas industry. The Pennsylvania Department of Environmental Protection has issued a General Permit, General Plan Approval and Permit Exemption 38 for natural gas dispensing facilities and oil and gas exploration, development, and production operations. Pennsylvania also applies conditions on flaring of emissions. Under the Permit 38 exemptions, there are criteria set out for the oil and natural gas industry that include unconditionally exempt and conditionally exempt criteria. Unconditionally exempt operations/equipment include conventional wells, conventional wellheads and associated equipment, well drilling, completion and work-over activities, and non-road engines. Unconventional wells, wellheads and associated equipment (including equipment components, storage vessels) are conditionally exempt. Conditions include compliance with 40 CFR part 60, subpart OOOO and Pennsylvania's General Permit 5 (GP-5) and a demonstration that the combined VOC emissions from all sources at a facility are less than 2.7 tons per year (tpy) on a 12-month rolling basis. For oil and natural gas facilities that do not meet these conditions, a case-by-case plan approval is required.[2]

There may also be local permit requirements for control of VOC emissions from existing sources of VOC emissions in the oil and natural gas industry, such as those required by the Bay Area Air Quality Management District (BAAQMD) for pneumatic controllers. The BAAQMD requires that a permit to operate applicant provide the number of high-bleed and low-bleed pneumatic devices in their permit application. Facilities that use high-bleed devices might be required to provide device-specific bleed rates and supporting documentation for each high-bleed device. In cases where emissions are high from high-bleed devices, BAAQMD might require that the facility conduct fugitive monitoring and/or control requirements under conditions of their permit to operate[3] on a case-by-case basis.

We conducted a search of the EPA's RACT/BACT/LAER Clearinghouse (RBLC) and identified several draft and final permits that covered some of the sources evaluated for RACT in this CTG. The controls specified in these permits are similar to the control options evaluated in this CTG.[4]

We considered these existing state and local requirements limiting VOC emissions from the oil and natural gas industry in preparing this guideline.

2.3 Development of this CTG

As discussed in section 2.1 of this chapter, the NSPS established VOC emission standards for certain new and modified sources in the oil and gas industry. This CTG addresses existing sources of VOC emissions and provides recommendations for RACT for the oil and natural gas industry. We developed our RACT recommendations after reviewing the 1983 CTG document, the oil and natural gas NSPS, existing state and local VOC emission reduction approaches, and information on costs, emissions and available VOC emission control technologies. In April 2014, the EPA released five technical white papers on potentially significant sources of emissions in the oil and natural gas industry. The white papers focused on

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[2] Pennsylvania Department of Environmental Protection. *Comparison of Air Emission Standards for the Oil & Natural Gas Industry* (Well Pad Operations, Natural Gas Compressor Stations, and Natural Gas Processing Facilities). May 23, 2014.
[3] Cheng, Jimmy. *Permit Handbook. Chapter 3.5 Natural Gas Facilities and Crude Oil Facilities.* Bay Area Air Quality Management District. September 16, 2013.
[4] RACT/BACT/LAER Clearinghouse website: http://cfpub.epa.gov/RBLC/.

technical issues covering emissions and mitigation techniques that target methane and VOC. We reviewed the white papers, along with the input we received from the peer reviewers and the public, when evaluating and recommending RACT.

This CTG reflects the evaluation of potential RACT options for emission sources that are regulated under the oil and natural gas NSPS. This CTG did not evaluate hydraulically fractured oil and natural gas well completions performed on existing wells because these operations are addressed in the NSPS.

Several of the technical support documents (TSDs) prepared in support of the NSPS actions for the oil and natural gas industry include data and analyses considered in developing RACT recommendations in this CTG. To the extent that the data and analyses are also relevant to control options for existing sources, they are referred to throughout this guidance document as follows:

(1) The TSD for the 2011 NSPS proposal, published in July, 2011 is referred to as the "2011 NSPS TSD".[5]
(2) The supplemental TSD for the 2012 final NSPS standards, published in April, 2012, is referred to as the "2012 NSPS TSD" or "2012 NSPS STSD"[6]
(3) The TSD for the 2015 proposal NSPS standards, published August, 2015, is referred to as the "2015 NSPS TSD".[7]
(4) The TSD for the 2016 final NSPS standards, published in May, 2016, is referred to as the "2016 NSPS TSD"[8]

Additionally, emission information and counts for various emission sources were summarized from facility-level data submitted to the Greenhouse Gas Reporting Program

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[5] 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.
[6] 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 the Final New Source Performance Standards*. April 2012. Docket ID No. EPA-HQ-OAR-2010-0505-4550.
[7] U.S. Environmental Protection Agency. *Oil and Natural Gas Source Category: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Technical Support Document for the Proposed Amendments to the New Source Performance Standards.* August 2015. (See Docket No. EPA-HQ-OAR-2010-0505-5021; regulations.gov).
[8] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources – Background Technical Support Document for the Final New Source Performance Standards*. May 2016.

(GHGRP)[9] and data used to calculate national emissions in the Inventory of U.S. Greenhouse Gas Emissions and Sinks (GHG Inventory).[10] For the purposes of this document, these data sources are referred to as the "GHGRP" and the "GHG Inventory". The most recent published data from the GHG Inventory when we prepared the draft CTG was for 2013, and was used for some of the analyses included in this document. Between the time we issued the draft CTG and the final CTG, GHGRP data was released that covers 2011 through 2014 and the most recent available GHG Inventory covers data from 1990 through 2014. These new activity data have been reviewed for this CTG and incorporated into our RACT analyses, as appropriate.

Most of the VOC emission estimates presented in this document are based on methane emissions data because we only had methane emissions information for the evaluated sources. We calculated VOC emissions using ratios of methane to VOC in the gas for the different segments of the industry. These ratios, and the procedures used to calculate them, are documented in a memorandum characterizing gas composition developed during the NSPS process. [11] Herein, we refer to this memorandum as the "2011 Gas Composition Memorandum". Because methane emissions are the basis for most of our VOC emission estimates, in several instances where we provide VOC emissions per source/model plant, we also provide the methane emissions that are the basis for our VOC emission estimates.

The remainder of this document is divided into seven chapters and an appendix. Chapter three describes the oil and natural gas industry and a summary of our RACT recommendations presented in this CTG. Chapters four through nine describe the oil and natural gas emission sources that we evaluated for our RACT recommendations (i.e., storage vessels, compressors, pneumatic controllers, pneumatic pumps, equipment component leaks from natural gas processing plants, and fugitive emissions from well sites and gathering and boosting stations), available control and regulatory approaches (including existing federal, state and local requirements) and the potential emission reductions and costs associated with available control and regulatory approaches for a given emission source. The appendix provides example model

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[9] U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2014. (Reported Data: http://www.epa.gov/ghgreporting/). The Greenhouse Gas Reporting Program has particular definitions of "facility" for certain petroleum and natural gas systems industry segments. See 40 CFR 98.238.
[10] U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Inventory and Sinks. 1990 - 2014*. Washington, DC. EPA 430-R-15-004. Available online at https://www.epa.gov/ghgemissions/us-greenhouse-gas-inventory-report-1990-2014.
[11] 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 No. EPA-HQ-OAR-2010-0505-0084.

rule language that can be used by air agencies as a starting point in the development of their SIP rules if they choose to adopt the recommended RACT presented in this document.

3.0 OVERVIEW OF THE OIL AND NATURAL GAS INDUSTRY AND SOURCES SELECTED FOR RACT RECOMMENDATIONS

Section 3.1 presents an overall description of the oil and natural gas industry and section 3.2 presents the VOC emission sources for which we are recommending RACT within the oil and natural gas industry. Table 3-1 provides a summary of recommendations for controlling VOC emissions from oil and natural gas industry emission sources.

3.1 Overview of the Oil and Natural Gas Industry

The oil and natural gas industry includes oil and natural gas operations involved in the extraction and production of crude oil and natural gas, as well as the processing, transmission, storage, and distribution of natural gas. For oil, the industry includes all operations from the well to the point of custody transfer at a petroleum refinery. For natural gas, the industry includes all operations from the well to the customer. For purposes of this document, the oil and natural gas operations are 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. We briefly discuss each of these segments below. For purposes of this CTG, oil and natural gas production includes only onshore operations.

Production operations include the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, and separation or treating 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 include 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, natural gas, and other materials and wastes from the wells to the refineries or natural gas processing plants.

There are two basic types of wells: oil wells and natural gas wells. Oil wells can have "associated" natural gas that is separated and processed or the crude oil can be the only product processed. Crude oil production includes the well and extends to the point of custody transfer to the crude oil transmission pipeline. Once the crude oil is separated from water and other impurities, it is essentially ready to be transported to the refinery via truck, railcar, or pipeline. The oil refinery sector is considered separately from the oil and natural gas industry. Therefore, at the point of custody transfer at the refinery, the oil leaves the oil and natural gas sector and enters the petroleum refining sector.

Natural gas is primarily made up of methane. It commonly exists in mixtures with other hydrocarbons. They are sold separately and have a variety of 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 produce "pipeline quality" dry natural gas. While some of the processing can be accomplished in the production segment, the complete processing of natural gas takes place in the natural gas processing segment. Natural gas processing operations separate and recover natural gas liquids (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 than intrastate pipelines, the basic components are the same. To ensure that the natural gas flowing through any pipeline remains pressurized, compression of the gas is required periodically along the pipeline. This is accomplished by compressor stations usually placed between 40 and 100 mile intervals along the pipeline. At a compressor station, the natural gas enters the station, where it is compressed by reciprocating or centrifugal compressors.

In addition to the pipelines and compressor stations, the natural gas transmission and storage segment includes aboveground and underground storage facilities. Underground natural gas storage includes subsurface storage, which typically consists of depleted gas or oil reservoirs and salt dome caverns used for storing natural gas. One purpose of this storage is for load balancing (equalizing the receipt and delivery of natural gas). At an underground storage site, there are typically other processes, including compression, dehydration, and flow measurement.

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. 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 natural 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 industry. Primarily, these emissions are organic compounds such as methane, ethane, VOC, and organic hazardous air pollutants (HAP). Figure 3-1 presents a schematic of oil and natural gas sector operations.

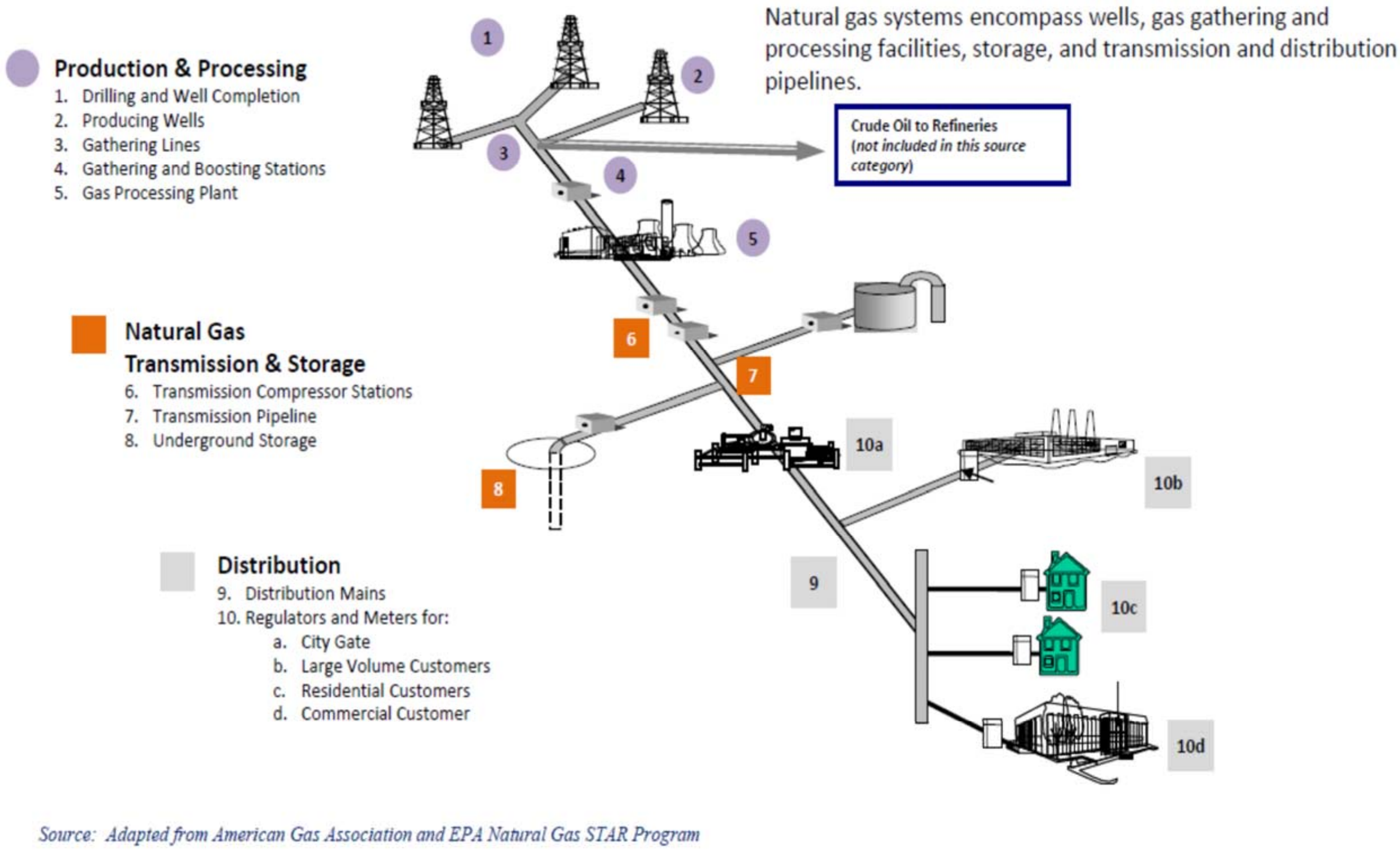

Figure 3-1. Oil and Natural Gas Sector Operations

3.2 Sources Selected For RACT Recommendations

This CTG covers select sources of VOC emissions in the onshore production and processing segments of the oil and natural gas industry (i.e., pneumatic controllers, pneumatic pumps, compressors, equipment leaks, fugitive emissions) and storage vessel VOC emissions in all segments (except distribution) of the oil and natural gas industry. These sources were selected for RACT recommendations because current information indicates that they are significant sources of VOC emissions. As mentioned in section 2.3, the VOC RACT recommendations contained in this document were made based on the review of the 1983 CTG document, the oil and natural gas NSPS, existing state and local VOC emission reduction approaches, and information on emissions, available VOC emission control technologies, and costs.

In considering costs, we compared control options and estimated costs and emission impacts of multiple emission reduction options under consideration. Recommendations are presented in this CTG for the subset of existing sources in the oil and natural gas industry where the application of controls is judged reasonable, given the availability of demonstrated control technologies, emission reductions that can be achieved, and the cost of control.

Table 3-1 presents a summary of the oil and natural gas emission sources and recommended RACT included in this CTG.

Table 3-1. Summary of the Oil and Natural Gas Industry Emission Sources and Recommended RACT Included in this CTG

Emission Source	Applicability	RACT Recommendations
Storage Vessels	Individual storage vessel with a potential to emit (PTE) greater than or equal to 6 tpy VOC.	95 percent reduction of VOC emissions from storage vessels. OR Maintain less than 4 tpy uncontrolled actual VOC emissions after having demonstrated that the uncontrolled actual VOC emissions have remained less than 4 tpy, as determined monthly, for 12 consecutive months.
Pneumatic Controllers	Individual continuous bleed, natural gas-driven pneumatic controller located at a natural gas processing plant.	Natural gas bleed rate of 0 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 0 scfh).
	Individual continuous bleed natural gas-driven pneumatic controller located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline.	Natural gas bleed rate less than or equal to 6 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 6 scfh).
Pneumatic Pumps	Individual natural gas-driven diaphragm pump located at a natural gas processing plant.	Zero VOC emissions.
	Individual natural gas-driven diaphragm pump located at a well site.	Require routing of VOC emissions from the pneumatic pump to an existing onsite control device or process.
		Require 95 percent control unless the onsite existing control device or process cannot achieve 95 percent.
		If onsite existing device or process cannot achieve 95 percent, maintain documentation demonstrating the percent reduction the control device is designed to achieve.

Emission Source	Applicability	RACT Recommendations
		If there is no existing control device at the location of the pneumatic pump, maintain records that there is no existing control device onsite.
	Individual natural gas-driven diaphragm pump located at a well site that is in operation for any period of time each calendar day for less than a total of 90 days per calendar year.	RACT would not apply.
Compressors (Centrifugal and Reciprocating)	Individual reciprocating compressor located between the wellhead and point of custody transfer to the natural gas transmission and storage segment.	Reduce VOC emissions by replacing reciprocating compressor rod packing on or before 26,000 hours of operation or 36 months since the most recent rod packing replacement. Alternatively, route rod packing emissions to a process through a closed vent system under negative pressure.
	Individual reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site.	RACT would not apply.
	Individual centrifugal compressor using wet seals that is located between the wellhead and point of custody transfer to the natural gas transmission and storage segment.	Reduce VOC emissions from each centrifugal compressor wet seal fluid gassing system by 95 percent.
	Individual centrifugal compressor using wet seals located at a well site, or an adjacent well site and servicing more than one well site.	RACT would not apply.
	Individual centrifugal compressor using dry seals.	RACT would not apply.
Equipment Leaks	Equipment components in VOC service located at a natural gas processing plant.	Implement the 40 CFR part 60, subpart VVa leak detection and repair (LDAR) program for natural gas processing plants.
Fugitive Emissions	Individual well site with wells with a gas to oil ratio (GOR) greater than or equal to 300, that produce, on average, greater than 15 barrel equivalents per well per day.	Develop and implement a semiannual optical gas imaging (OGI) monitoring and repair plan that covers the collection of fugitive emissions components at well sites within a company defined area. Method 21 can be

Emission Source	Applicability	RACT Recommendations
		used as an alternative to OGI at a 500 ppm repair threshold level.
	Individual gathering and boosting station located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or point of custody transfer to an oil pipeline.	Develop and implement a quarterly OGI monitoring and repair plan that covers the collection of fugitive emissions components at gathering and boosting stations within a company defined area. Method 21 can be used as an alternative to OGI at a 500 ppm repair threshold.
	Individual well site with a GOR less than 300.	RACT would not apply.

4.0 STORAGE VESSELS

Storage vessels are significant sources of VOC emissions in the oil and natural gas industry. This chapter provides a description of the types of storage vessels present in the oil and natural gas industry, and provides VOC emission estimates for storage vessels, in terms of mass of emissions per throughput, for both crude oil and condensate storage vessels. This chapter also presents control techniques used to reduce VOC emissions from storage vessels, along with their costs and potential emission reductions. Finally, this chapter provides a discussion of our recommended RACT for storage vessels.

4.1 Applicability

For purposes of this CTG, the emissions and emission controls discussed herein would apply to a tank or other vessel in the oil and natural gas industry that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of non-earthen materials (such as wood, concrete, steel, fiberglass, or plastic) that provide structural support. The emissions and emission controls discussed herein would not apply to the following vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships), and are intended to be located at a site for less than 180 consecutive days.

(2) Process vessels such as surge control vessels, bottoms receivers, or knockout vessels.

(3) Pressure vessels designed to operate in excess of 204.9 kilopascals (29.7 pounds per square inch) and without emissions to the atmosphere.[12]

4.2 Process Description and Emission Sources

4.2.1 Process Description

Storage vessels in the oil and natural gas industry are used to hold a variety of liquids including crude oil, condensates, produced water, etc. While still underground and at reservoir pressure, crude oil contains many lighter hydrocarbons in solution. When the oil is brought to the

[12] It is acknowledged that even pressure vessels designed to operate without emissions have a small potential for fugitive emissions at valves. Valves are threaded components that would be subject to leak detection and repair requirements.

surface, many of the dissolved lighter hydrocarbons (as well as water) are removed through a series of separators. Crude oil is passed through either a two-phase separator (where the associated gas is removed and any oil and water remain together) or a three-phase separator (where the associated gas is removed and the oil and water are also separated). The remaining oil is then directed to a storage vessel where it is stored for a period of time before being transported off-site. Much of the remaining hydrocarbon gases in the oil are released from the oil as vapors in the storage vessels. Storage vessels are typically installed with similar or identical vessels in a group, referred to in the industry as a tank battery.

Emissions of the hydrocarbons from storage vessels are a function of flash, breathing (or standing), and working losses. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas industry, flashing losses occur when crude oils or condensates flow into an atmospheric storage vessel from a processing vessel (e.g., a separator) operated at a higher pressure. Typically, the larger the pressure drop, the more flash emissions will occur in the storage vessel. The temperature of the liquid may also influence the amount of flash emissions. Breathing losses are the release of gas associated with temperature fluctuations and other equilibrium effects. Working losses occur when vapors are displaced due to the emptying and filling of storage vessels. The volume of gas vapor emitted from a storage vessel depends on many factors. Lighter crude oils flash more hydrocarbons than heavier crude oils. In storage vessels where the oil is frequently cycled and the overall throughput is high, working losses are higher. Additionally, the operating temperature and pressure of oil in the separator dumping into the storage vessel will affect the volume of flashed gases coming out of the oil.

The composition of the vapors from storage vessels varies, and the largest component is methane, but also may include ethane, butane, propane, and HAP such as benzene, toluene, ethylbenzene and xylenes (commonly referred to as BTEX), and n-hexane.

4.2.2 Emissions Data

4.2.2.1 Summary of Major Studies and Emissions

There are numerous studies and reports available that estimate storage vessel emissions. We consulted several of these studies and reports to evaluate the emissions and emission reduction options for storage vessels. Table 4-1 presents a summary of the references for these reports, along with an indication of the type of information available in each reference.

Table 4-1. Major Studies Reviewed for Consideration of Emissions and Activity Data[a,b]

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[e]
VOC Emissions from Oil and Condensate Storage Tanks	Texas Environmental Research Consortium	2009	Regional	X	X
Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation – Final Report	Texas Commission on Environmental Quality	2009	Regional	X	
Initial Economic Impact Analysis for Proposed State Implementation Plan Revisions to the Air Quality Control Commission's Regulation Number 7	Colorado Air Quality Control Commission	2008	NA		X
E&P TANKS	API		National	X	
Inventory of U.S. Greenhouse Gas Emissions and Sinks[c]	EPA	Annual	National	X	
Greenhouse Gas Reporting Program (Annual Reporting: Current Data Available for 2011-2013)[d]	EPA	2014	Facility-Level	X	X

NA = Not Applicable.

[a] 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 the Final New Source Performance Standards*. April 2012. EPA Docket ID No. EPA-HQ-OAR-2010-0505-4550.

[b] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Technical Support*. July 2011. EPA-453/R-11-002.

[c] U.S Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html.

[d] U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2014.

[e] An "X" in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

4.2.2.2 Representative Storage Vessel Baseline Emissions

Storage vessels vary in size and throughputs. In support of the 2013 NSPS Reconsideration,[13] average storage vessel emissions, in terms of mass of emissions per throughput, were developed for both crude oil and condensate storage vessels.[14] We also developed mass emissions per throughput estimates using the American Petroleum Institute's (API's) E&P TANKS program and more than 100 storage vessels across the country with varying characteristics.[15] The VOC emissions per throughput estimates used for this analysis are:

(1) Uncontrolled VOC Emissions from Crude Oil Storage Vessels = 0.214 tpy VOC/barrel per day (bbl/day); and

(2) Uncontrolled VOC Emissions from Condensate Storage Vessels = 2.09 tpy VOC/bbl/day.

On a nationwide basis, there are a wide variety of storage vessel sizes, as well as rates of throughput for each tank. Emissions are directly related to the throughput of liquids for a given storage vessel; therefore, in support of the 2013 NSPS Reconsideration, we adopted production rate brackets developed by the U.S. Energy Information Administration (U.S. EIA) for our emission estimates. To estimate the emissions from an average storage vessel within each production rate bracket, we developed average production rates for each bracket. This average was calculated using the U.S. EIA published nationwide production per well per day for each production rate bracket from 2006 through 2009. Table 4-2 presents the average oil production and condensate production in barrels per well per day. For this analysis, we considered the liquid produced (as reported by the U.S. EIA) from oil wells to be crude oil and from gas wells to be condensate. Table 4-2 presents the average VOC emissions for each storage vessel within each production rate bracket calculated by applying the average production rate (bbl/day) to the VOC emissions per throughput estimates (tpy VOC/bbl/day).

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[13] 78 FR 58416, September 23, 2013. The EPA issued final updates to its 2012 VOC performance standards for storage tanks used in crude oil and natural gas production and transmission. The amendments reflected updated information that responded to issues raised in several petitions for reconsideration of the 2012 standards.

[14] Brown, Heather, EC/R Incorporated. Memorandum prepared for Bruce Moore, EPA/OAQPS/SPPD/FIG. *Revised Analysis to Determine the Number of Storage Vessels Projected to be Subject to New Source Performance Standards for the Oil and Natural Gas Sector*. 2013.

[15] American Petroleum Institute. *Production Tank Emissions Model. E&P Tank Version 2.0. A Program for Estimating Emissions from Hydrocarbon Production Tanks*. Software Number 4697. April 2000.

Table 4-2. Average Oil and Condensate Production and Storage Vessel Emissions per Production Rate Bracket[16]

Production Rate Bracket (BOE/day)[a]	Oil Wells: Average Oil Production Rate per Oil Well (bbl/day)[b]	Oil Wells: Crude Oil Storage Vessel VOC Emissions (tpy)[c]	Gas Wells: Average Condensate Production Rate per Gas Well (bbl/day)[b]	Gas Wells: Condensate Storage Vessel VOC Emissions (tpy)[c]
0-1	0.385	0.083	0.0183	0.038
1-2	1.34	0.287	0.0802	0.168
2-4	2.66	0.570	0.152	0.318
4-6	4.45	0.953	0.274	0.573
6-8	6.22	1.33	0.394	0.825
8-10	8.08	1.73	0.499	1.04
10-12	9.83	2.11	0.655	1.37
12-15	12.1	2.59	0.733	1.53
15-20	15.4	3.31	1.00	2.10
20-25	19.9	4.27	1.59	3.32
25-30	24.3	5.22	1.84	3.85
30-40	30.5	6.54	2.55	5.33
40-50	39.2	8.41	3.63	7.59
50-100	61.6	13.2	5.60	11.7
100-200	120	25.6	12.1	25.4
200-400	238	51.0	23.8	49.8
400-800	456	97.7	44.1	92.3
800-1,600	914	196	67.9	142
1,600-3,200	1,692	363	148	311
3,200-6,400	3,353	719	234	490
6,400-12,800	6,825	1,464	891	1,864
> 12,800[d]	0	0	0	0

Minor discrepancies may be due to rounding.
[a] BOE=Barrels of Oil Equivalent
[b] Oil and condensate production rates published by U.S. EIA. "United States Total Distribution of Wells by Production Rate Bracket."
[c] Oil storage vessel VOC emission factor = 0.214 tpy VOC/bbl/day. Condensate storage vessel VOC emission factor = 2.09 tpy/bbl/day.
[d] There were no new oil and gas well completions in 2009 for this rate category. Therefore, average production rates were set to zero.

[16] Brown, Heather, EC/R Incorporated. Memorandum prepared for Bruce Moore, EPA/OAQPS/SPPD/FIG. *Revised Analysis to Determine the Number of Storage Vessels Projected to be Subject to New Source Performance Standards for the Oil and Natural Gas Sector*. 2013.

4.3 Available Controls and Regulatory Approaches

In analyzing available controls for storage vessels, we reviewed information obtained in support of the 2012 NSPS[17] and the 2013 NSPS Reconsideration actions, control techniques identified in the Natural Gas STAR program, and existing state regulations that require control of VOC emissions from storage vessels in the oil and natural gas industry. Section 4.3.1 presents a non-exhaustive discussion of available VOC emission control methods for storage vessels. Section 4.3.2 includes a summary of the federal, state, and local regulatory approaches that control VOC emissions from crude oil and condensate storage vessels.

4.3.1 Available VOC Emission Control Options

The options generally used as the primary means to limit the amount of VOC vented are to: (1) route emissions from the storage vessel through an enclosed system to a process where emissions are recycled, recovered, or reused in the process – "route to a process" (e.g., by installing a vapor recovery unit (VRU) that recovers vapors from the storage vessel) for reuse in the process or for beneficial use of the gas onsite and/or (2) route emissions from the storage vessel to a combustion device. While EPA explored these options within the document, there may be other emission controls that sources may wish to employ to ensure continuous compliance with EPA's RACT recommendation. Regardless of the type of emission control method that a source may choose to utilize, the recommended RACT level of control explained more fully below is meant to apply at all times. One of the clear advantages the first option has over the second option is that it results in a cost savings associated with the recycled, recovered and reused natural gas and other hydrocarbon vapor, rather than the loss and destruction of the natural gas and vapor by combustion. Combustion and partial combustion of organic pollutants also creates secondary pollutants including nitrogen oxides, carbon monoxide, sulfur oxides, carbon dioxide and smoke/particulates. These emission control methods are described below along with their emission reduction control effectiveness as they apply to storage vessels in the industry and the potential costs associated with their installation and operation.

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[17] *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standard for Hazardous Air Pollutants Reviews. Final Rule*. 77 FR 49490, August 16, 2012.

4.3.1.1 Routing Emissions to a Process via a Vapor Recovery Unit (VRU)

Description

One option for controlling storage vessel emissions is to route vapors from the storage vessel back to the inlet line of a separator, to a sales gas line, or to some other line carrying hydrocarbon fluids for beneficial use, such as use as a fuel. Where a compressor is used to boost the recovered vapors into the line, this is often referred to as a VRU.[18] Typically with a VRU, hydrocarbon vapors are drawn out of the storage vessel under low pressure and are piped to a separator, or suction scrubber, to collect any condensed liquids, which are usually recycled back to the storage vessel. Vapors from the separator flow through a compressor that provides the low-pressure suction for the VRU system where the recovered hydrocarbons can be transported to various places, including a sales line and/or for use onsite.

Types of VRUs include conventional VRUs and venturi ejector vapor recovery units (EVRU™) or vapor jet systems.[19] Decisions on the type of VRU to use are based on the applicability needs (e.g., an EVRU™ is recommended where there is a high-pressure gas compressor with excess capacity and a vapor jet VRU is suggested where there is produced water, less than 75 million cubic feet (MMcf)/day gas and discharge pressures below 40 pounds per square inch gauge (psig)). The reliability and integrity of the compressor and suction scrubber and integrity of the lines that connect the tank to the compressor will affect the effectiveness of the VRU system to collect and recycle vapors.[20]

A conventional VRU is equipped with a control pilot to shut down the compressor and permit the back flow of vapors into the tank in order to prevent the creation of a vacuum in the top of a tank when liquid is withdrawn and the liquid level drops. Vapors are then either sent to the pipeline for sale or used as onsite fuel. Figure 4.1 presents a diagram of a conventional VRU installed on a single crude oil storage vessel (multiple tank installations are also common).[21]

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[18] American Petroleum Institute. Letter to Bruce Moore, SPPD/OAQPS/EPA from M. Todd, API. *Re: Oil and Natural Gas Sector Consolidated Rulemaking*. Docket ID No. EPA-HQ-OAR-2010-0505.
[19] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Installing Vapor Recovery Units.* Natural Gas STAR Program. Source Reduction Training to Interstate Oil and Gas Compact Commission Presentation. February 27, 2009.
[20] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Installing Vapor Recovery Units on Storage Tanks*. Natural Gas STAR Program. October 2006.
[21] Ibid.

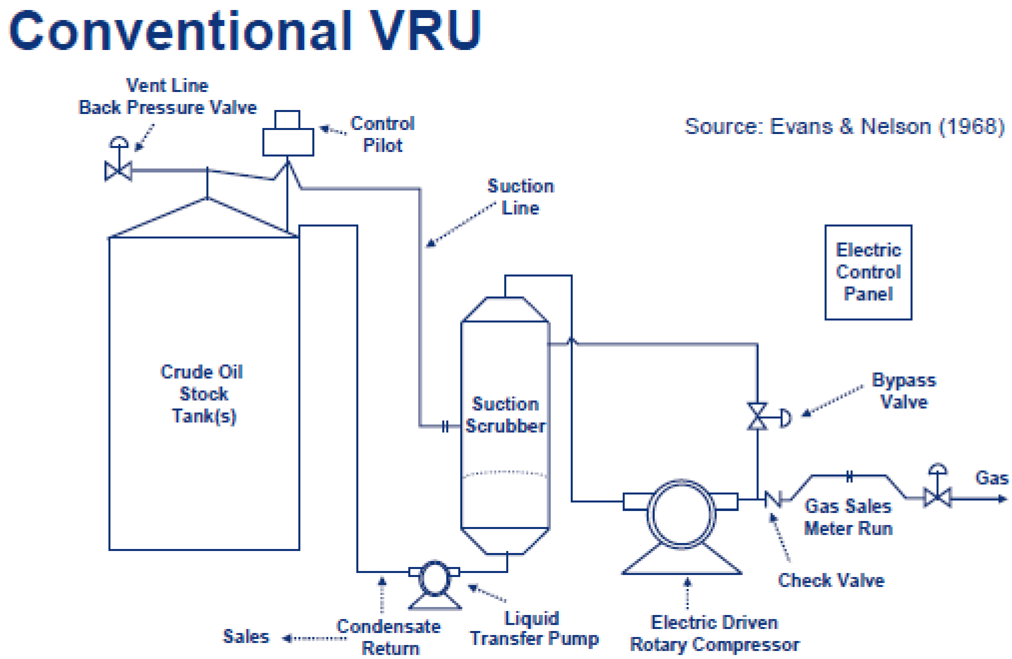

Figure 4-1. Conventional Vapor Recovery System

Control Effectiveness

Vapor recovery units have been shown to reduce VOC emissions from storage vessels by over 95 percent.[22] When operating properly, VRUs generally approach 100 percent efficiency. We recognize that VRUs may not continuously meet this efficiency in practice. Therefore, our analysis assumes a 95 percent reduction in VOC emissions for a VRU. A VRU recovers hydrocarbon vapors that potentially can be used as supplemental burner fuel, or the vapors can be condensed and collected as condensate that can be sold. If natural gas is recovered, it can be sold as well, as long as a gathering line is available to convey the recovered salable gas product to market or to further processing. A VRU cannot be used in all instances. Conditions that affect the feasibility of the use of a VRU include: the availability of electrical service sufficient to power the compressor; fluctuations in vapor loading caused by surges in throughput and flash emissions from the storage vessel; potential for drawing air into condensate storage vessels causing an explosion hazard; and lack of appropriate destination or use for the vapor recovered.

[22] Ibid.

Cost Impacts

Cost data for a VRU obtained from an initial economic impact analysis prepared for proposed state-only revisions to a Colorado regulation are presented here.[23] We assumed cost information contained in the Colorado economic impact analysis to be given in 2012 dollars. According to the Colorado economic impact analysis, the cost of a VRU was estimated to be $90,000. Including costs associated with freight and design, and the cost of VRU installation, we estimated costs to be $102,802 ($90,000 plus $12,802). We also added an estimated storage vessel retrofit cost of $68,736 assuming that the cost of retrofitting an existing storage vessel was 75 percent of the purchased equipment cost (i.e., VRU capital cost and freight and design cost).[24] Based on these costs, we estimated the total capital investment of the VRU to be $171,538. These cost data are presented in Table 4-3. We estimated total annual costs using 2012 dollars to be $28,230 per year without recovered natural gas savings. The uncontrolled emissions from a storage vessel are largely dependent on the bbl/year throughput (see Table 4-2), which greatly influences both the controlled emissions and the cost of control per ton of VOC reduced. Costs may vary due to VRU design capacity, system configuration, and individual site needs and recovery opportunities.

In order to assess the cost of control of a VRU for uncontrolled storage vessels that emit differing emissions, we evaluated the cost of routing VOC emissions from an existing uncontrolled storage vessel to a VRU for a storage vessel that emits 2 tpy, 4 tpy, 6 tpy, 8 tpy, 10 tpy, 12 tpy, and 25 tpy. We estimated the cost of control without savings by dividing the total annual costs without savings by the tpy reduced assuming 95 percent control. The cost of control with savings is calculated by assuming a 95 percent reduction of VOC emissions by the VRU and converting the reduced VOC emissions to natural gas savings. Table 4-4 presents the estimated natural gas savings and the VOC cost per ton of VOC reduced with and without savings.

[23] Initial Economic Impact Analysis for Proposed Revisions to the Colorado Air Quality Control Commission Regulation Number 7, *Emissions of Volatile Organic Compounds*. November 15, 2013.
[24] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Installing Vapor Recovery Units on Storage Tanks.* Natural Gas STAR Program. October 2006.

Table 4-3. Total Capital Investment and Total Annual Costs of a Vapor Recovery Unit System

Cost Item[a]	Cost ($2012)
Capital Cost Items	
VRU[a]	$90,000
Freight and Design[a]	$1,648
VRU Installation[a]	$11,154
Storage Vessel Retrofit[b]	$68,736
Total Capital Investment	$171,538
Annual Cost Items	
Maintenance	$9,396
Capital Recovery (7 percent interest, 15 year equipment life) ($/yr)	$18,834
Total Annual Costs w/o Savings ($/yr)	***$28,230***

[a] Cost data from the Initial Economic Impact Analysis for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7, Submitted with Request for Hearing Documents on November 15, 2013.
[b] Assumes the storage vessel retrofit cost is 75 percent of the purchased equipment price (assumed to include vent system and piping to route emissions to the control device). Retrofit assumption from Exhibit 6 of the EPA Natural Gas Star Lessons Learned, *Installing Vapor Recovery Units on Storage Tanks*. October 2006.

Table 4-4. Cost of Routing Emissions from an Existing Uncontrolled Storage Vessel to a VRU ($/ton of VOC Reduced)

Uncontrolled Storage Vessel Emissions (tpy)	Cost per Ton of VOC Reduced ($2012)		
	Without Savings	Natural Gas Savings (Mscf/yr)[a]	With Savings[b]
2	$14,858	59	$14,734
4	$7,429	118	$7,305
6	$4,953	177	$4,828
8	$3,714	236	$3,590
10	$2,972	295	$2,847
12	$2,476	353	$2,352
25	$1,189	736	$1,065

[a] The natural gas savings was calculated by assuming 95 percent VOC recovery and 31 Mscf/yr natural gas savings per ton of VOC recovered.
[b] Assumes a natural gas price of $4.00 per Mcf.

Additionally, if a VRU is used to control VOC emissions from multiple storage vessels, the VOC emissions cost of control would be reduced because the cost for the additional storage vessel(s) would only include the storage vessel retrofit costs, and the overall VOC emission reductions would increase.

4.3.1.2 Routing Emissions to a Combustion Device

Description and Control Effectiveness

Combustors (e.g., enclosed combustion devices, thermal oxidizers and flares that use a high-temperature oxidation process) are also used to control emissions from storage vessels. Combustors are used to control VOC in many industrial settings, since the combustor can normally handle fluctuations in concentration, flow rate, heating value, and inert species content.[25] For this analysis, we assumed that the types of combustors installed in the oil and natural gas industry can achieve at least a 95 percent control efficiency on a continuing basis. [26] We note that combustion devices can be designed to meet 98 percent control efficiencies, and can control, on average, emissions by 98 percent or more in practice when properly operated.[27] We also recognize that combustion devices that are designed to meet a 98 percent control efficiency may not continuously meet this efficiency in practice, due to factors such as variability of field conditions.

A typical combustor used to control emissions from storage vessels in the oil and natural gas industry is an enclosed combustion system. The basic components of an enclosed combustion system include (1) piping for collecting emission source gases, (2) a single- or multiple-burner unit, (3) a stack enclosure, (4) a pilot flame to ignite the mixture of emission source gas and air and (5) combustor fuel/piping (as necessary). Figure 4-2 presents a schematic of a typical dual-burner enclosed combustion system.

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[25] U.S. Environmental Protection Agency. AP 42, Fifth Edition, Volume I, *Chapter 13.5 Industrial Flares*. Office of Air Quality Planning & Standards. 1991.
[26] U.S. Environmental Protection Agency. *Air Pollution Control Technology Fact Sheet: FLARE*. Clean Air Technology Center.
[27] The EPA has currently reviewed performance tests submitted for 19 different makes/models of combustor control devices and confirmed that they meet the performance requirements in NSPS subpart OOOO and NESHAP subparts HH and HHH. All reported control efficiencies were above 99.9 percent at tested conditions. The EPA notes that the control efficiency achieved in the field is likely to be lower than the control efficiency achieved at a bench test site under controlled conditions, but we believe that these units should have no problem meeting 95 percent control continuously and 98 percent control on average when designed and properly operated to meet 98 percent control.

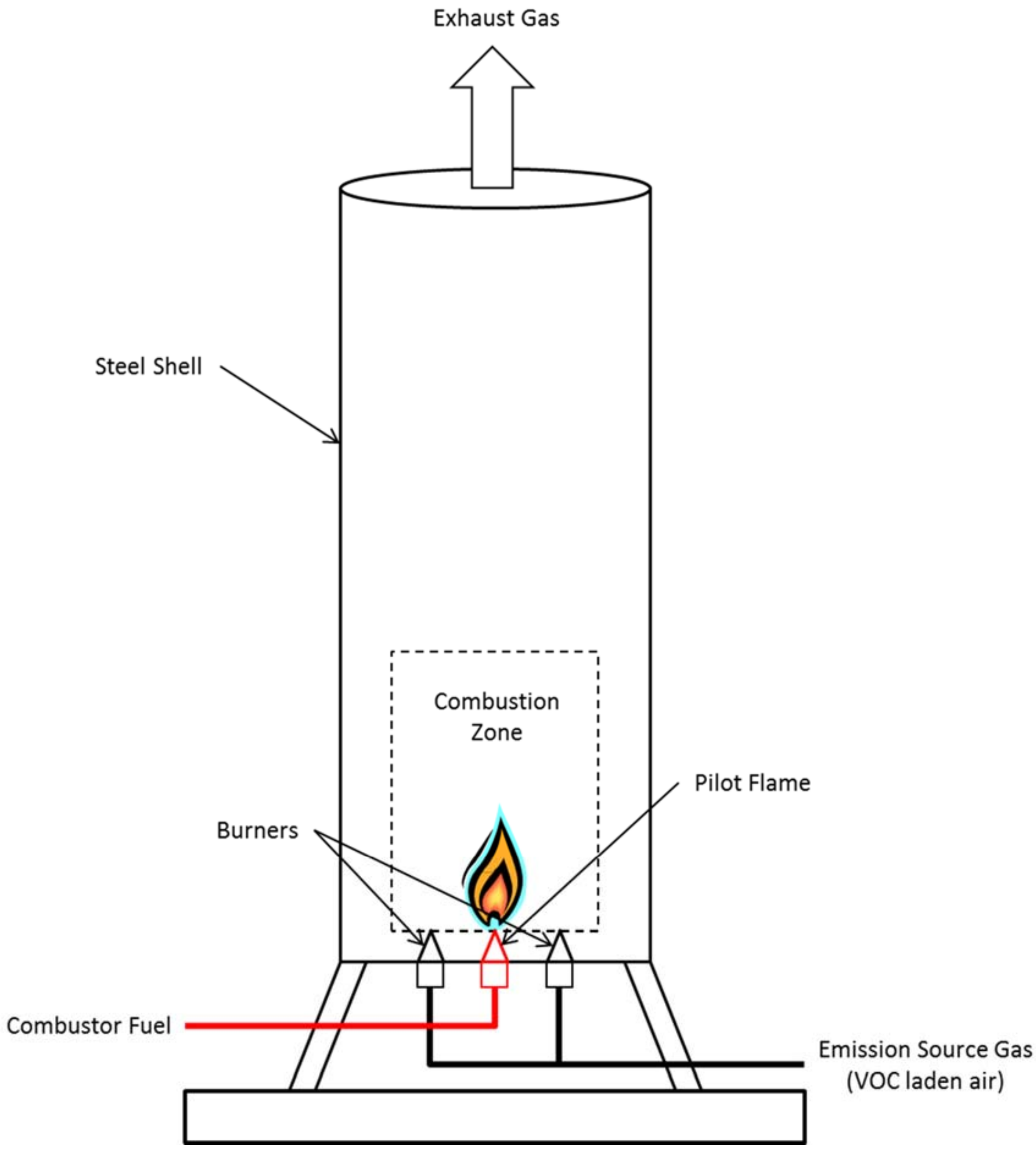

Figure 4-2. Schematic of a Typical Enclosed Combustion System

Thermal oxidizers, also referred to as direct flame incinerators, thermal incinerators, or afterburners, could also be used to control VOC emissions. Similar to a basic enclosed combustion device, a thermal oxidizer uses burner fuel to maintain a high temperature (typically 800-850°C) within a combustion chamber. The VOC laden emission source gas is injected into the combustion chamber where it is oxidized (burned), and then the combustion products are exhausted to the atmosphere. Figure 4-3 provides a basic schematic of a thermal oxidizer.[28]

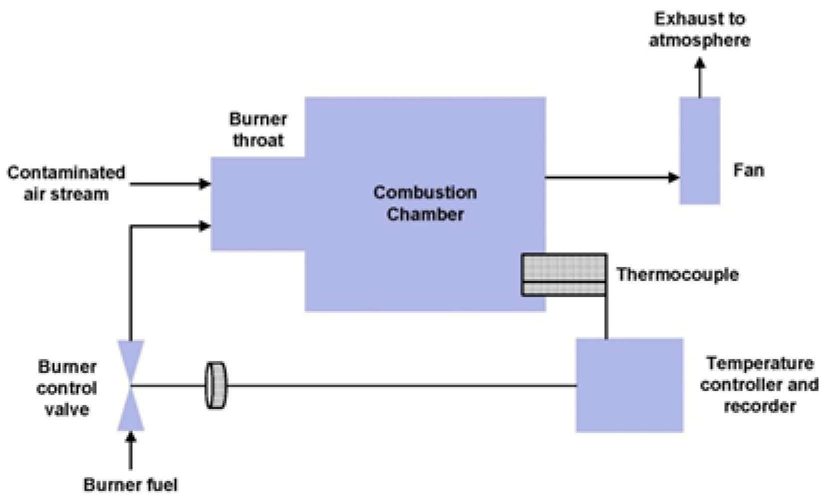

Figure 4-3. Basic Schematic of a Thermal Oxidizer

<u>Cost Impacts</u>

For combustion devices, we obtained cost data from the initial economic impact analysis prepared for state-only revisions to the Colorado regulation.[29] In addition to these cost data, we added line items for operating labor, a surveillance system and data management. This is consistent with the guidelines outlined in the EPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (OCCM) for combustion devices and the cost analysis prepared for the 2012 NSPS.[30,31] However, OCCM guidelines specify 630 operating labor hours

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[28] U.S. Environmental Protection Agency. Technology Transfer Network. Clearinghouse for Inventories and Emission Factors. *Thermal Oxidizer*. Website: https://cfpub.epa.gov/oarweb/mkb/contechnique.cfm?ControlID=17.
[29] Initial Economic Impact Analysis for Proposed Revisions to the Colorado Air Quality Control Commission Regulation Number 7, *Emissions of Volatile Organic Compounds*. November 15, 2013.
[30] *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standard for Hazardous Air Pollutants Reviews. Final Rule*. 77 FR 49490, August 16, 2012.
[31] U.S. Environmental Protection Agency. *OAQPS Control Cost Manual: Sixth Edition* (EPA 452/B-02-001). Research Triangle Park, NC.

per year for a combustion device, which we believe is unreasonable because many of these sites are unmanned and would most likely be operated remotely. Therefore, we assumed that the operating labor would be more similar to that estimated for a condenser in the OCCM, 130 hours per year. We estimated a total capital investment of $100,986 and total annual costs of $25,194 per year. The total capital investment cost includes a storage vessel retrofit cost of $68,736 (as discussed previously for VRUs) to accommodate the use of a combustion device. These cost data are presented in Table 4-5.

Table 4-5. Total Capital Investment and Total Annual Costs of a Combustor[32]

Cost Item[a]	Cost ($2012)
Capital Cost Items	
Combustor[a]	$18,169
Freight and Design[a]	$1,648
Auto Ignitor[a]	$1,648
Surveillance System[b,c,d]	$3,805
Combustor Installation[a]	$6,980
Storage Vessel Retrofit[e]	$68,736
Total Capital Investment	$100,986
Annual Cost Items	
Operating Labor[f]	$5,155
Maintenance Labor[f]	$4,160
Non-Labor Maintenance[a]	$2,197
Pilot Fuel	$1,537
Data Management[c]	$1,057
Capital Recovery (7 percent interest, 15 year equipment life) ($/yr)	$11,088
Total Annual Cost ($/yr)	$25,194

[a] Cost data from Initial Economic Impact Analysis for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7, Submitted with Request for Hearing Documents on November 15, 2013.
[b] Surveillance system identifies when pilot is not lit and attempts to relight it, documents the duration of time when the pilot is not lit, and notifies and operator that repairs are necessary.

[32] 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 the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

[c] 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 the Final New Source Performance Standards*. April 2012. EPA Docket ID No.EPA-HQ-OAR-2010-0505-4550.
[d] Cost obtained from 2012 NSPS TSD and escalated using the change in GDP: Implicit Price Deflator from 2008 to 2012 (percent)(which was 5.69 percent). Source: FRED GDP: Implicit Price Deflator from Jan 2008 to Jan 2012 (http://research.stlouisfed.org/fred2/series/GDPDEF/#).
[e] Retrofit cost obtained from Storage Vessel Retrofit in Table 4-3 (assumed to include vent system and piping to route emissions to the control device).
[f] Operating labor consists of labor resources for technical operation of device (130 hr/yr) and supervisory labor (15 percent of technical labor hours). Maintenance labor hours are assumed to be the same as operating labor (130 hr/yr). Labor rates are $32.00/hr (for technical and maintenance labor) and $51.03 (supervisory labor) and were obtained from the U.S. Department of Labor, Bureau of Labor Statistics, Employer Costs for Employee Compensation, December 2012. Labor rates account for total compensation (wages/salaries, insurance, paid leave, retirement and savings, supplemental pay and legally required benefits).

As noted previously, storage vessels vary in size and throughputs and the uncontrolled emissions from a storage vessel are largely dependent on the bbl/year throughput (see Table 4-2), which greatly influences both the controlled emissions and cost of control. In order to assess the cost of control of combustion for uncontrolled storage vessels that emit differing emissions, we evaluated the costs of routing VOC emissions from an existing storage vessel to a combustion device for an existing uncontrolled storage vessel that emits 2 tpy, 4 tpy, 6 tpy, 8 tpy, 10 tpy, 12 tpy and 25 tpy. We estimated the cost of control without savings by dividing the total annual costs without savings by the tpy reduced assuming 95 percent control. Table 4-6 presents these costs. The VOC emissions cost of control per ton of VOC reduced would be less if a combustion device is used to control uncontrolled VOC emissions from multiple storage vessels because the cost for the additional storage vessel(s) would only include storage vessel retrofit costs, and the overall VOC emission reductions would increase.

Table 4-6. Cost of Routing Emissions from an Existing Uncontrolled Storage Vessel to a Combustion Device ($/ton of VOC Reduced)

Uncontrolled Storage Vessel Emissions (tpy)	Cost per Ton of VOC Reduced ($2012)
2	$13,260
4	$6,630
6	$4,420
8	$3,315

Uncontrolled Storage Vessel Emissions (tpy)	Cost per Ton of VOC Reduced ($2012)
10	$2,652
12	$2,411
25	$2,210

4.3.1.3 Routing Emissions to a VRU with a Combustion Device as Backup

Industry practice also includes the primary operation of a VRU and secondary operation of a combustion device during VRU maintenance and other times requiring VRU downtime. Using the costs for a VRU and combustion device presented in sections 4.3.1.1 and 4.3.1.2, and assuming the VRU is operated 95 percent of the year and a combustion device is operated 5 percent of the year, we estimated total annual costs using 2012 dollars to be $32,006 per year without recovered natural gas savings. As stated previously, the uncontrolled emissions from a storage vessel are largely dependent on the bbl/year throughput (see Table 4-2), which greatly influences both the controlled emissions and the cost of control per ton of VOC reduced. Costs may vary due to VRU design capacity, system configuration, and individual site needs and recovery opportunities, as well as the percent of time that a VRU is down during the year where emissions are routed to a combustion device. In order to assess the cost of control of a VRU with the use of a combustion device during downtime for uncontrolled storage vessels that emit differing emissions, we evaluated the costs of routing VOC emissions from an existing storage vessel to a VRU/combustion device for an existing uncontrolled storage vessel that emits 2 tpy, 4 tpy, 6 tpy, 8 tpy, 10 tpy, 12 tpy and 25 tpy. We estimated the cost of control without savings by dividing the total annual costs without savings by the tpy reduced assuming 95 percent control. The cost of control with savings is calculated by assuming a 95 percent reduction of VOC emissions by the VRU (used 95 percent of the year) and converting the reduced VOC emissions to natural gas savings. Table 4-7 presents these costs. The VOC emissions cost of control per ton of VOC reduced would be less if a VRU/combustion device is used to control uncontrolled VOC emissions from multiple storage vessels because the cost for the additional storage vessel(s) would only include storage vessel retrofit costs, and the overall VOC emission reductions would increase.

Table 4-7. Cost of Routing Emissions from an Existing Uncontrolled Storage Vessel to a VRU/Combustion Device ($/ton of VOC Reduced)

Uncontrolled Storage Vessel Emissions (tpy)	Cost per Ton of VOC Reduced ($2012)		
	Without Savings	Natural Gas Savings (Mscf/yr)[a]	With Savings[b]
2	$16,845	56	$16,728
4	$8,423	112	$8,305
6	$5,615	168	$5,497
8	$4,211	224	$4,094
10	$3,369	280	$3,251
12	$2,808	336	$2,690
25	$1,348	699	$1,230

[a] The natural gas savings was calculated by assuming 95 percent VOC recovery and 31 Mscf/yr natural gas savings per ton of VOC recovered.
[b] Assumes a natural gas price of $4.00 per Mcf.

4.3.2 Existing Federal, State and Local Regulations

4.3.2.1 Federal Regulations that Specifically Require Control of VOC Emissions

Under the 2012 NSPS and 2013 NSPS Reconsideration, new or modified storage vessels with PTE VOC emissions of 6 tpy or more must reduce VOC emissions by at least 95 percent, or demonstrate emissions from a storage vessel have dropped to less than 4 tpy of VOC without emission controls for 12 consecutive months.

4.3.2.2 State and Local Regulations that Specifically Require Control of VOC Emissions[33]

States may have permitting restrictions on VOC emissions that may apply to an emissions source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met, and how the source must be operated. To ensure that sources

[33] Brown, Heather, EC/R Incorporated. Memorandum prepared for Bruce Moore, EPA/OAQPS/SPPD/FIG. *Revised Analysis to Determine the Number of Storage Vessels Projected to be Subject to New Source Performance Standards for the Oil and Natural Gas Sector.* 2013.

follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

The environmental regulations in nine of the top oil and natural gas producing states (sometimes with varying local ozone nonattainment area/concentrated area development requirements) (see Table 4-8) require the control of VOC emissions from storage vessels in the oil and natural gas industry. These states include California, Colorado, Kansas, Louisiana, Montana, North Dakota, Oklahoma, Texas, and Wyoming. All except Wyoming require 95 percent emission control with the application of a VRU or combustion (Wyoming requires 98 percent control of emissions using a VRU or combustion).

Existing state regulations that apply to storage vessels in the oil and natural gas industry apply to all storage vessels in a tank battery, or include an applicability threshold based on (1) capacity, (2) the vapor pressure of liquids contained in a storage vessel of a specified capacity, and (3) the PTE of an individual storage vessel. Table 4-8 presents a brief summary of the storage vessel emission control applicability cutoffs in regulations from these nine states. Four states (Colorado, Montana, Texas, and Wyoming) have applicability thresholds in terms of VOC emissions. The remaining five states have storage vessel regulations that are in terms of tank characteristics, such as vapor pressure, tank size, or tank contents. Equivalency of applicability thresholds based on tank and stored liquid characteristics and applicability thresholds based on VOC emissions cannot be determined. We analyzed the varying state VOC emission thresholds (based on a range of 2 tpy to 25 tpy) as part of our cost of control analysis for VRUs and combustion devices in section 4.3.1 of this chapter.

Table 4-8. Summary of Storage Vessel Applicability Thresholds from Nine States

State/Local Authority	Applicability Threshold
Texas	Applies to storage vessels with VOC emissions greater than 25 tpy.
California Bay Area AQMD	Applies to storage vessels with capacity greater than 264 gallons.
California Feather River AQMD	Applies to storage vessels with capacity greater than 39,630 gallons.
California Monterey Bay Unified APCD	Applies to storage vessels with capacity greater than 39,630 gallons.

State/Local Authority	Applicability Threshold
California Sacramento Metropolitan AQMD	Applies to storage vessels with capacity greater than 40,000 gallons.
California San Joaquin Valley Unified APCD	Applies to storage vessels with capacity greater than 1,100 gallons.
California Santa Barbara County APCD	Applies to all storage vessels in tank battery (including wash tanks, produced water tanks, and wastewater tanks).
California South Coast AQMD	Applies to storage vessels with capacity greater than 39,630 gallons with a true vapor pressure of 0.5 psia or greater and storage vessels with a capacity greater than 19,815 gallons with a true vapor pressure of 1.5 psia or greater.
California Ventura County APCD	Applies to all storage vessels. Requirements depend on gallon capacity and true vapor pressure of material contained in vessel.
California Yolo-Solano AQMD	Applies to storage vessels with capacity greater than 40,000 gallons.
North Dakota	NDAC 33-15-07: submerged filling requirements to control VOC for tanks >1,000 gallons.
Federal Implementation Plan (FIP): Fort Berthold Indian Reservation	Applies to all storage vessels (except those covered by NSPS subpart OOOO). There is no minimum threshold under the final FIP.
Louisiana	Applies to storage vessels more than 250 gallons up to 40,000 gallons with a maximum true vapor pressure of 1.5 psia or greater.
Oklahoma	Applies to storage vessels with capacity greater than 40,000 gallons (in ozone nonattainment areas).
Wyoming – Statewide	Applies to storage vessels with greater than or equal to 10 tpy VOC within 60 days of startup/modification.
Wyoming – Concentrated Development Area	Applies to storage vessels with greater than or equal to 8 tpy VOC within 60 days of startup/modification.
Kansas	Permanent fixed roof storage tanks >40,000 gallons and external floating roof storage tanks.
Colorado	Condensate tanks with uncontrolled VOC emissions > 20 tpy (2 tpy located at gas processing plants in ozone non-attainment areas).

State/Local Authority	Applicability Threshold
Montana	Applies to oil or condensate storage tanks with a PTE greater than 15 tpy VOC.

4.4 Recommended RACT Level of Control

As discussed in section 4.3.2 of this chapter, existing federal and state and local regulations already require the reduction of VOC emissions from storage vessels in the oil and natural gas industry at or greater than 95 percent. Further, we note that combustion devices can be designed to meet 98 percent control efficiencies and can control, on average, emissions by 98 percent or more in practice when properly operated.[34] We also recognize that combustion devices designed to meet 98 percent control efficiency may not continuously meet this efficiency in practice, due to factors such as the variability of field conditions. Therefore, the recommendations specify that devices should be required to continuously meet at least 95 percent VOC control efficiency. In light of the above considerations, a continuous 95 percent reduction of VOC emissions from storage vessels in the oil and natural gas industry is a reasonable recommended RACT level of control.

Although sources may have a choice on how they meet the recommended RACT level of control, if air agencies choose to adopt the recommended RACT contained in this CTG, the technologies that may be used to meet the recommended RACT level of control for oil and natural gas industry storage vessels are capturing and routing emissions to the process via a VRU and/or routing emissions to a combustion device.

As discussed in section 4.2.2 of this chapter, the VOC emissions from storage vessels vary significantly, depending on the rate of liquid entering and passing through the vessel (i.e., its throughput), the pressure of the liquid as it enters the atmospheric pressure storage vessel, the liquid's volatility, and temperature of the liquid. Some storage vessels have negligible emissions, such as those with very little throughput and/or handling heavy liquids entering at atmospheric

[34] The EPA has currently reviewed performance tests submitted for 19 different makes/models of combustor control devices and confirmed they meet the performance requirements in NSPS subpart OOOO and NESHAP subparts HH and HHH. All reported control efficiencies were above 99.9 percent at tested conditions. EPA notes that the control efficiency achieved in the field is likely to be lower than the control efficiency achieved at a bench test site under controlled conditions, but we believe that these units should have no problem meeting 95 percent control continuously and 98 percent control on average when designed and properly operated to meet 98 percent control.

pressure where it would not be cost-effective to require emission control requirements. Existing state regulations that apply to storage vessels in the oil and natural gas industry apply to all storage vessels in a tank battery, or include an applicability threshold based on (1) capacity, (2) the vapor pressure of liquids contained in a storage vessel of a specified capacity, and (3) the PTE of an individual storage vessel. Based on information gathered under the 2012 NSPS,[35] throughput and capacity of a storage vessel is not always the best indicator of a storage vessel's emissions, and we believe that the PTE of an individual storage vessel is preferable to use as an applicability threshold for storage vessels.

Based on our analyses conducted in support of the 2012 NSPS, 6 tpy was determined to be the applicability threshold for requiring 95 percent control of VOC emissions from new storage vessels (estimated to cost, on average, approximately $3,400 per ton of VOC reduced). Our analyses conducted for our RACT recommendation also found 6 tpy to be the applicability threshold for requiring 95 percent control of VOC emissions from existing storage vessels (estimated to cost, on average, between $4,400 and $5,000 per ton of VOC reduced). Based on these analyses, we recommend that the 95 percent VOC emission control of storage vessels only apply to storage vessels that have a PTE greater than or equal to 6 tpy of VOC emissions. The VOC cost of control per ton of VOC reduced would be less if a combustion device or VRU is used to control VOC emissions from multiple storage vessels because the cost for the additional storage vessels would only include storage vessel retrofit costs, and the overall VOC emission reductions would increase.

We recommend an alternative RACT level of control for storage vessels that have a PTE VOC at or greater than 6 tpy that have actual emissions less than that on a continuing basis. For these storage vessels, if it can be demonstrated that the storage vessel has actual emissions less than 4 tpy for 12 consecutive months, we recommend that they be allowed to maintain and show continued compliance that their emissions are below 4 tpy in lieu of requiring 95 percent control. This alternative recommendation acknowledges that there are storage vessels that have a PTE greater than or equal to 6 tpy whose actual emissions have declined over time, usually because of declining production. This alternative RACT recommendation is informed by the 2012 NSPS, where we concluded that, based on "the cost-effectiveness, the secondary environmental impacts

[35] 77 FR 49490, August 16, 2012.

and the energy impacts…BSER for reducing VOC emissions from storage vessel affected facilities is not represented by continued control when their sustained (i.e., for 12 consecutive months) uncontrolled emission rates fall below 4 tpy."[36]

In summary, we recommend the following as RACT for storage vessels in the oil and natural gas industry:

(1) RACT for Condensate Storage Vessels: Reduce emissions by 95 percent continuously from condensate storage vessels with a PTE $\geq$ 6 tpy of VOC; or demonstrate (based on 12 consecutive months of uncontrolled actual emissions) and maintain uncontrolled actual VOC emissions from storage vessels with a PTE greater than or equal to 6 tpy at less than 4 tpy.[37]

(2) RACT for Crude Oil Storage Vessels: Reduce emissions by 95 percent continuously from crude oil storage vessels with a PTE $\geq$ 6 tpy of VOC; or demonstrate (based on 12 consecutive months of uncontrolled actual emissions) and maintain uncontrolled actual VOC emissions from storage vessels with a PTE greater than or equal to 6 tpy at less than 4 tpy.[38]

4.5 Factors to Consider in Developing Storage Vessel Compliance Procedures

4.5.1 Compliance Recommendations When Using a Control Device

Improper design or operation of the storage vessel and its control system can result in occurrences where peak flow overwhelms the storage vessel and its capture systems, resulting in emissions that do not reach the control device, effectively reducing the control efficiency. We believe that it is essential that operators employ properly designed, sized, and operated storage vessels to achieve effective emission control. We believe that such efforts on the part of owners and operators can result in more effective control of VOC emissions from storage vessels.

In order to ensure that VOC emissions are reduced by at least 95 percent (the recommended RACT level of control) from a storage vessel when using a control device or other

[36] Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards Final Amendments. Federal Register Notice. (78 FR 58429, September 23, 2013).

[37] We recommend that, prior to allowing the use of the uncontrolled 4 tpy actual VOC emissions rate for compliance purposes, air agencies require sources demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy for 12 consecutive months. After such demonstration, we recommend that air agencies require that sources demonstrate continued compliance with the uncontrolled actual VOC emission rate each month.

[38] See footnote 37.

control measure (such as routing to a process), the storage vessel should be equipped with a cover that is connected through a closed vent system that captures and routes emissions to the control device (or process). We recommend cover, closed vent system and control device design and compliance measures to ensure that control measures meet the RACT level of control. Recommended cover and closed vent system design and operation measures are specified in sections 4.5.1.1 and 4.5.1.2. Recommended control device operation and monitoring provisions for specified controls to ensure compliance are presented in sections 4.5.1.3 and 4.5.1.4. The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part.

4.5.1.1 Recommendations for Cover Design

The cover and all openings on the cover (e.g., access hatches, sampling ports, pressure relief valves, and gauge wells) should form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel. Each cover opening should be secured in a closed, sealed position (gasket lid or cap) whenever material is in the unit except when it is necessary to open as follows:

(1) To add material to or remove material from the unit (including openings necessary to equalize or balance the internal pressure of the unit following changes in the level of material in the unit);
(2) To inspect or sample the material in the unit;
(3) To inspect, maintain, repair, or replace equipment located in the unit; or
(4) To vent liquids, gases or fumes from the unit through a closed vent system designed and operated in accordance with specified closed vent system requirements (see section 4.5.1.2) or to a process.

It is recommended that air agencies require the storage vessel thief hatch be equipped, maintained and operated with a weight, or other mechanism, to ensure that the lid remains properly seated. It is recommended that air agencies require the gasket material for the hatch be selected based on composition of the fluid in the storage vessel and weather conditions.

It is also recommended that air agencies require monthly olfactory, visual and auditory inspections of covers for defects that could result in air emissions. Any detected defects should be required to be repaired as soon as practicable.

4.5.1.2 Recommendations for Closed Vent Systems

The closed vent system should be designed and operated with no detectable emissions (which can be monitored by monthly olfactory, visual and auditory inspections). It is recommended that air agencies require that any detected defects be repaired as soon as practicable.

With the exception of low leg drains, high point bleeds, analyzer vent, open-ended valves and safety devices, if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process, it is recommended that air agencies require owners and operators either:

(1) Install, calibrate, maintain and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere; or

(2) Secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

4.5.1.3 Recommendations When "Routing to a Process" or to a VRU

Routing to a process would entail routing emissions via a closed vent system to any enclosed portion of a process unit where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product and/or recovered. Vapor recovery units and flow lines that "route emissions to a process" would be considered part of the process and would not be considered control devices that are subject to standards, but the recommended cover and closed vent system design, operation and monitoring requirements specified in sections 4.5.1.1 and 4.5.1.2 would apply.

4.5.1.4 Recommendations for Control Device Operation and Monitoring

If a control device is used to comply with the recommended 95 percent VOC emission reduction RACT level of control, it is recommended that air agencies require that the device operate at all times when gases, vapors, and fumes are vented from the storage vessel subject to VOC emission requirements through the closed vent system to the control device.

For control devices used to meet the recommended RACT, it is recommended that air agencies require owners and operators follow the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

If an owner or operator complies with the recommended RACT by using a combustion device, it is recommended that air agencies require initial and periodic performance testing (no later than 60 months after the initial performance test) to demonstrate initial and continued compliance with the recommended RACT level of control. Additionally, for each combustion device used to comply with the recommended continuous 95 percent VOC emission reduction, it is recommended that air agencies require owners and operators conduct the following control device compliance assurance measures: (1) Monthly visual inspections or monitoring to confirm that the pilot is lit when vapors are routed to it. (2) Monthly inspections to monitor for visible emissions from the combustion device using section 11 of EPA Method 22 of appendix A of part 60. It is recommended that the observation period be 15 minutes and that devices be operated with no visible emissions, except for periods not to exceed a total of one minute during any 15-minute period. (3) Monthly olfactory, visual and auditory inspections associated with the combustion device to ensure system integrity.

4.5.2 Compliance Recommendations When Complying with the 4 tpy VOC Emissions Alternative Limitation

If the alternative RACT recommendation to determine and maintain the uncontrolled actual VOC emissions from a storage vessel that has a PTE to emit greater than or equal to 6 tpy at less than 4 tpy without considering control is used, it is recommended that air agencies first require that a source demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, it is recommended that air agencies require that the source determine the uncontrolled actual VOC emission rate each month using a generally accepted model or calculation methodology. It is also recommended that such calculations be based on the average throughput for the month. If the monthly emissions determination indicates that VOC emissions from a storage vessel subject to VOC emission control requirements increases to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel, it is recommended that air agencies require that the source comply with the 95 percent VOC emission reduction RACT level of control recommendation or that emissions be routed to a VRU.

5.0 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 sources of VOC emissions from these compressors. This chapter also provides control techniques used to reduce VOC emissions from these compressors, along with costs and emission reductions. Finally, this chapter provides a discussion of our recommended RACT and the associated VOC emission reductions and costs for both reciprocating and centrifugal compressors.

5.1 Applicability

For the purposes of this CTG, the emissions and emission reductions discussed herein would apply to centrifugal and reciprocating compressors in the oil and natural gas industry located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. As noted in section 3.2 of this document, we did not evaluate RACT for compressors located at a well site, or an adjacent well site and servicing more than one well site.

5.2 Process Description and Emission Sources

5.2.1 Process Description

5.2.1.1 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 packaging system needs to be replaced to prevent excessive leaking from the compression cylinder. See Figure 5-1 for a depiction of a typical rod compressor packing system configuration.[39]

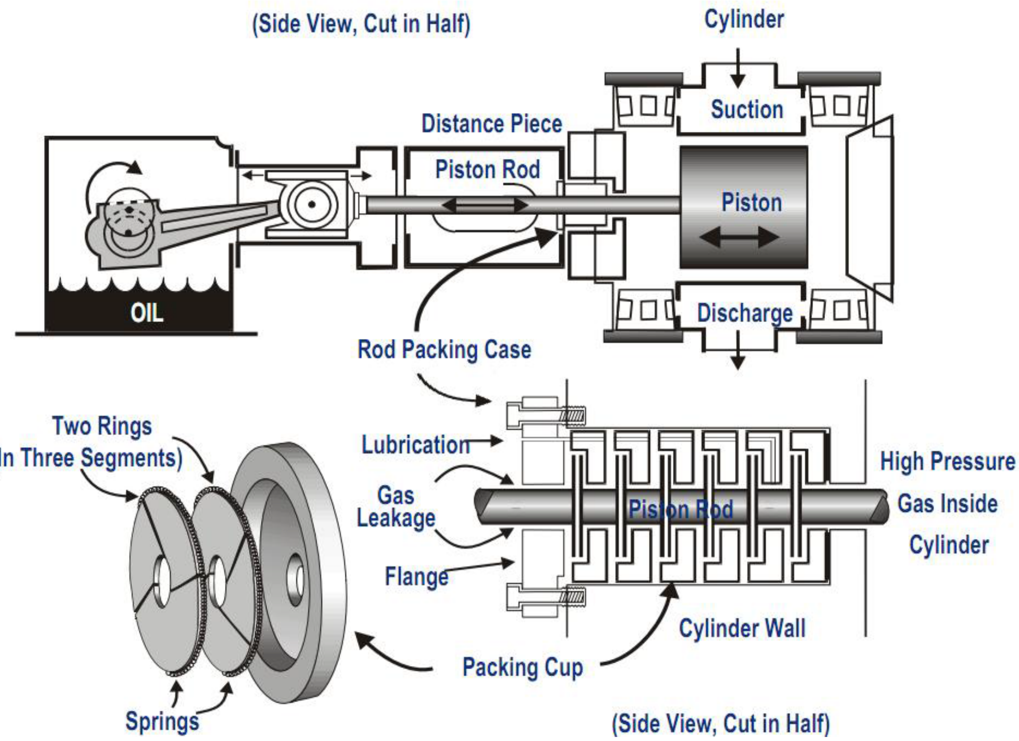

Figure 5-1. Typical Reciprocating Compressor Rod Packing System Diagram

5.2.1.2 Centrifugal Compressors

Centrifugal compressors use a rotating disk or impeller to increase the velocity of the natural 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

[39] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR Program. 2006.

adsorbs some compressed natural gas that may be released to the atmosphere during the seal oil recirculation process. Figure 5-2 illustrates the wet seal compressor configuration.[40]

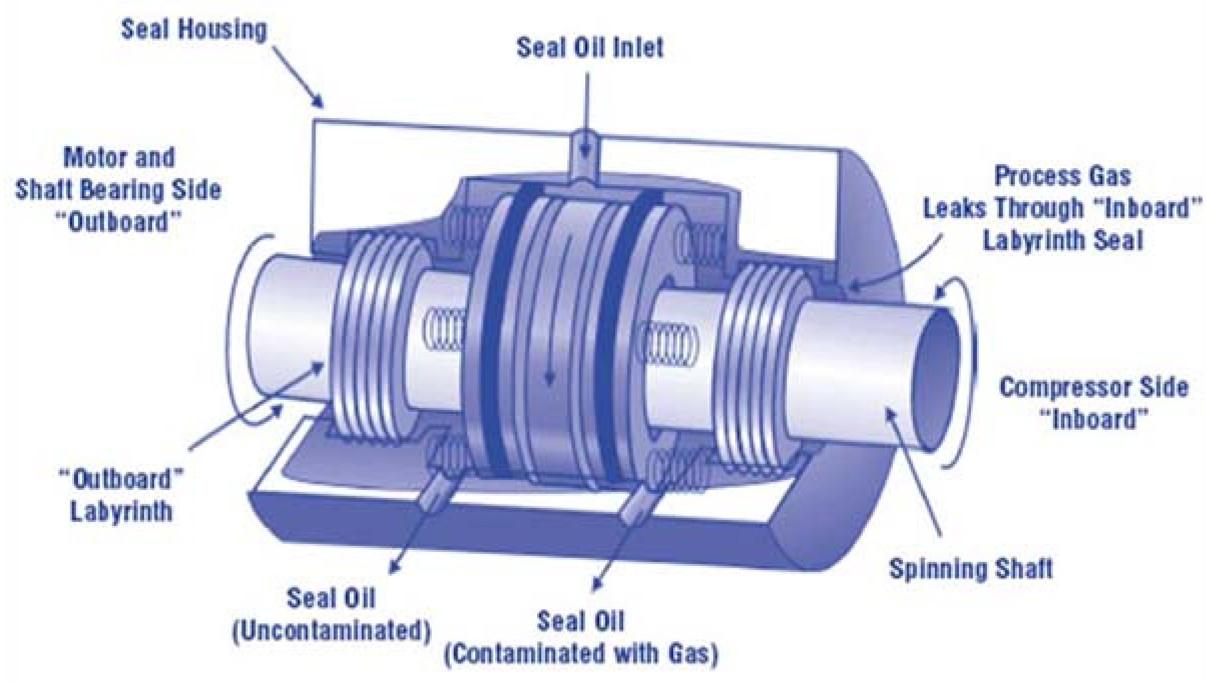

Figure 5-2. Typical Centrifugal Compressor Wet Seal

Alternatively, dry seals can be used in place of wet seals in centrifugal compressors. Dry seals prevent leakage by using the opposing force created by hydrodynamic grooves and springs (see Figure 5-3). 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 natural gas has only one pathway to leak down the shaft, and that is between the rotating and stationary rings. This natural gas is pumped between the grooves in the rotating and stationary rings. The opposing force of high-pressure natural gas pumped between the rings and springs trying to push the rings together creates a very thin gap between the rings through which little natural gas can leak. While the compressor is operating, the rings are not in

[40] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Replacing Wet Seals with Dry Seals in Centrifugal Compressors*. Natural Gas STAR Program. October 2006.

contact with each other and, therefore, do not wear or need lubrication. O-rings seal the stationary rings in the seal case.[41]

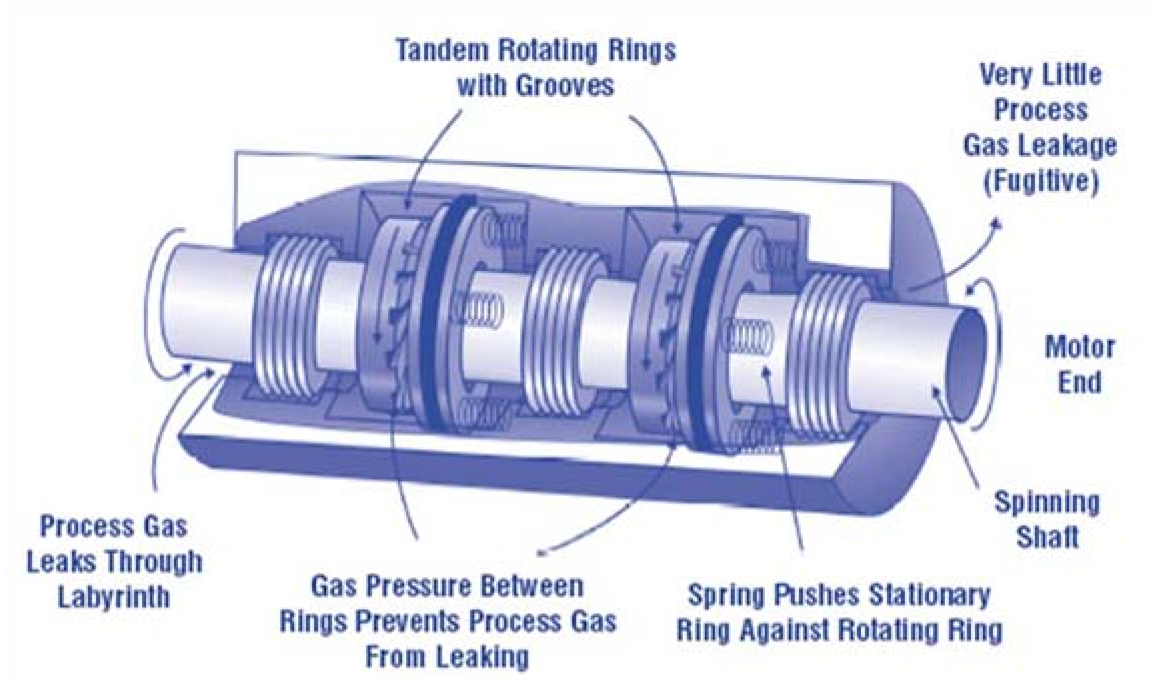

Figure 5-3. Typical Centrifugal Compressor Tandem Dry Seal

Natural gas emissions from wet seal centrifugal compressors have been found to be higher than dry seal compressors primarily due to the off-gassing of the entrained natural gas from the oil. This natural gas is not suitable for sale and is either released to the atmosphere, flared, or routed back to a process. In addition to lower natural gas leakage (and therefore lower emissions), dry seals have been found to have lower operation and maintenance costs than wet seal compressors because they are a mechanically simpler design, require less power to operate, and are more reliable. For the same reasons we explained in the 2012 NSPS and the 2015 NSPS proposal, we are not recommending RACT for dry seal compressors and instead include the use of a dry seal in place of a wet seal system as an available control option for reducing VOC emissions from wet seal centrifugal compressors (discussed in section 5.3.1.2 of this chapter). During the rulemakings for the 2012 NSPS and 2016 NSPS, we found that the dry seal system and the option of routing to a process both had at least a 95 percent control efficiency.

[41] Ibid.

5.2.2 Emissions Data

5.2.2.1 Summary of Major Studies and Emissions

Several studies have been conducted that provide leak estimates from reciprocating and centrifugal compressors. Table 5-1 lists these studies, along with the type of information contained in the study. In addition to these sources, we evaluated the peer reviewer and public comments received on the EPA's white paper, "Oil and Natural Gas Sector Compressors."[42]

Table 5-1. Major Studies Reviewed for Emissions Data[43]

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

[42] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Compressors. Report for Oil and Natural Gas Sector Compressors Review Panel*. Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415compressors.pdf.

[43] 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 the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

[a] U.S Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html.
[b] U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2014.
[c] U.S. Environmental Protection Agency/GRI. National Risk Management Research Laboratory. 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.
[d] U.S. Environmental Protection Agency. *Lessons Learned: Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR. Environmental Protection Agency. 2006.
[e] U.S. Environmental Protection Agency. *Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors*. Natural Gas STAR. Environmental Protection Agency. October 2006.
[f] URS Corporation/University of Texas at Austin. 2011. *Natural Gas Industry Methane Emission Factor Improvement Study, Final Report*. December 2011. http://www.utexas.edu/research/ceer/GHG/files/FReports/XA_83376101_Final_Report.pdf.
[g] American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA). *Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production. Summary and Analysis of API and ANGA Survey Responses*. Final Report. September 21, 2012.
[h] The API/ANGA study provided information on equipment counts that could augment nationwide emissions calculations. No source emission information was included.
[i] ICF International. *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.
[j] An "X" in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

5.2.2.2 Representative Reciprocating and Centrifugal Compressor Emissions

The centrifugal compressor methane emission factors used for processing are based on emission factor data for wet seals and dry seals from a sampling of wet seal and dry seal centrifugal compressor data that was used to calculate emissions in the GHG Inventory.

For gathering and boosting station reciprocating compressors, the 2011 NSPS TSD emission factors were used because they are considered to be the best representative emission factors at this time. Emission factors in the Clearstone study,[44] which are expressed in thousand standard cubic feet per cylinder, were multiplied by the average number of cylinders per gathering and boosting station reciprocating compressor. The volumetric methane emission rate was converted to a mass emission rate using a density of 41.63 pounds of methane per thousand cubic feet. This conversion factor was developed assuming that methane is an ideal gas and using the ideal gas law to calculate the density. A summary of the reciprocating compressor methane

[44] Clearstone Engineering Ltd. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*. 2006.

emission factors used for this analysis is presented in Table 5-2. Once the mass methane emission rate was calculated, ratios were used to estimate VOC emissions using the methane to VOC pollutant ratios developed in the 2011 Gas Composition Memorandum. The specific ratio that was used to convert methane emissions to VOC emissions is 0.278 pounds VOC per pound of methane for the production and processing segments. Table 5-3 presents a summary of the estimated methane and VOC emissions per reciprocating and centrifugal compressor (in tpy) for the production and processing segments.

Table 5-2. Methane Emission Factors for Reciprocating and Centrifugal Compressors[45]

Oil and Gas Industry Segment	Reciprocating Compressors			Centrifugal Compressors	
	Methane Emission Factor (scfh-cylinder)	Average Number of Cylinders	Pressurized Factor (Percent of Hours/Year Compressor Pressurized)	Wet Seal Methane Emission Factor (scfm)	Dry Seal Methane Emission Factor (scfm)
Gathering & Boosting Stations	25.9[a]	3.3	79.1%	N/A[c]	N/A[c]
Processing	57[b]	2.5	89.7%	47.7[d]	6[d]

[a] Clearstone Engineering Ltd. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*. 2006.
[b] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks*. Table 4-14.
[c] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry: Volume 11 – Compressor Driver Exhaust*. 1996 Report does not report any centrifugal compressors in the production or gathering/boosting segments, therefore no emission factor data were published for those two segments.
[d] U.S Environmental Protection Agency. *Methodology for Estimating CH_4 and CO_2 Emissions from Petroleum Systems. Greenhouse Gas Inventory: Emission and Sinks 1990-2012*. Washington, DC. April 2014.

[45] U.S. Environmental Protection Agency/GRI. Research and Development, National Risk Management Research Laboratory. *Methane Emissions from the Natural Gas Industry*. Prepared for the U.S. Department of Energy, Energy Information Administration. EPA-600/R-96-080h. June 1996.

Table 5-3. Baseline VOC Emission Estimates for Reciprocating and Centrifugal Compressors[a]

Industry Segment/Compressor Type	Baseline Emission Estimates (tpy)	
	Methane	VOC
Reciprocating Compressors		
Gathering and Boosting Stations	12.3	3.42
Processing	22	6.12
Centrifugal Compressors (Wet seals)		
Processing	210.53	19.1
Centrifugal Compressors (Dry seals)		
Processing	26	2.4

[a] For centrifugal compressors, it was assumed that 75 percent of the natural gas that is compressed is pipeline quality gas and 25 percent of the natural gas is production quality.

5.3 Available Controls and Regulatory Approaches

5.3.1 Available VOC Emission Control Options

Available controls for reducing VOC emissions from reciprocating and centrifugal compressors are presented in sections 5.3.1.1 and 5.3.1.2 of this chapter.

5.3.1.1 Reciprocating Compressors

Potential control options for reducing emissions from reciprocating compressors include control techniques that limit the leaking of natural gas past the piston rod packing. These options include: (1) increasing or specifying the frequency of the replacement of the compressor rod packing, (2) increasing or specifying the frequency of the replacement of the piston rod, (3) specifying the refitting or realignment of the piston rod, and (4) routing of emission to a process through a closed vent system under negative pressure. In addition to these options, there are emerging control techniques where specific analyses have not yet been conducted. For example, there may be potential for reducing VOC emission by updating rod packing components made from newer materials which can help improve the life and performance of the rod packing system (economic rod packing replacement) and capturing gas from the reciprocating compressor and routing it back to the compressor engine to be used as fuel. These emerging VOC emissions control techniques are discussed briefly below, along with our evaluation of the frequency of compressor rod packing/piston rod replacement and piston rod refitting and realignment control options.

We do not believe that combustion is a technically feasible control option because, as detailed in the 2011 NSPS TSD, routing of emissions to a control device can cause positive back pressure on the packing, which can cause safety issues due to gas backing up in the distance piece area and engine crankcase in some designs. While considering the option of routing of emissions to a process through a closed vent system under negative pressure, we determined that the negative pressure requirement not only ensures that all the emissions are conveyed to the process, it also avoids the issue of inducing back pressure on the rod packing and the resultant safety concerns. Although this option can be used in some circumstances, it cannot be applied in every installation. As a result, these options (i.e., routing of emissions to a control device, routing of emissions to a process through a closed vent system under negative pressure) were not further considered under this CTG.

Frequency of Rod Packing Replacement

For reciprocating compressors, one of the options for reducing VOC emissions is a maintenance task that would increase or specify the frequency of replacement of the rod packing in order 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 VOC emissions. Therefore, this control technique is considered to be an available VOC emission control technique for reciprocating compressors.

Description

As noted previously, 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 natural 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 natural gas will escape. Periodically replacing the packing rings ensures the correct fit is maintained between packing rings and the rod. [46]

[46] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR Program. 2006.

Control Effectiveness

As discussed above, regular replacement of the reciprocating compressor rod packing can reduce the leaking of natural gas across the piston rod. The potential emission reductions for gathering and boosting stations and the processing segment were calculated by comparing the average rod packing emissions with the average emissions from newly installed and worn-in rod packing.

Based on industry information from the Natural Gas STAR Program, we have determined that the additional cost of shortening the replacement period more frequently than every three years or every 26,000 hours would not be justified based on the additional emission reductions that would be achieved.[47] Therefore, we analyzed emission reductions that would result from replacing worn packing with newly installed packing at a frequency of every three years or every 26,000 hours. For the baseline, we assumed that rod packing is replaced every four years. The analysis uses Equation 1 for estimating gathering and boosting station emission reductions, and Equation 2 for estimating processing segment emission reductions that would result from replacing worn packing with newly installed packing at a frequency of every 3 years or every 26,000 hours.[48]

Equation 1 $$R_{WP}^{G\&B} = \frac{Comp_{Existing}^{G\&B}\left(E_{G\&B} - E_{New}\right) \times C \times O \times 8760}{10^6}$$

Where:

$R_{WP}^{G\&B}$ = Potential methane emission reductions from gathering and boosting stations by replacing worn packing with newly installed packing, in million cubic feet per year (MMcf/year);

$Comp_{Existing}^{G\&B}$ = Number of existing gathering and boosting station compressors;

$E_{G\&B}$ = Methane emission factor for gathering and boosting stations, in cubic feet per hour per cylinder (25.9 scfh-cylinder);

[47] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews. 40 CFR Parts 60 and 63. Response to Public Comments on Proposed Rule*. August 23, 2011 (76 FR 52738). pg. 102.

[48] 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 Document Number EPA-453/R-11-002.

E_{New} = Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder[49] for this analysis;

C = Average number of cylinders for gathering and boosting stations (i.e., 3.3);

O = Percent of time during the calendar year the average gathering and boosting station is in the operating and standby pressurized modes, 79.1 percent;

8760 = Number of hours in a year;

10^6 = Number of cubic feet in a million cubic feet.

Equation 2 $$R_P = \frac{Comp^{P}_{Existing}\left(E_P - E_{New}\right)\times C\times O\times 8760}{10^6}$$

Where:

R_P = Potential methane emission reductions from processing compressors replacing worn packing to newly installed packing, in million cubic feet per year (MMcf/year);

$Comp^{P}_{Existing}$ = Number of existing processing compressors;

E_P = Methane emission factor for processing compressors, in cubic feet per hour per cylinder, 57 scfh-cylinder;

E_{New} = Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder[50] for this analysis;

C = Average number of cylinders for processing compressors (i.e., 2.5);

O = Percent of time during the calendar year the average processing compressor is in the operating and standby pressurized modes, 89.7 percent;

8760 = Number of hours in a year;

10^6 = Number of cubic feet in a million cubic feet.

Table 5-4 presents a summary of the potential emission reductions for reciprocating compressor rod packing replacement for gathering and boosting stations and processing segment compressors based on the percent natural gas reduction calculated from the above equations. The emissions of VOC were estimated using the methane emissions calculated

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[49] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR Program. 2006.
[50] Ibid.

above and the methane-to-VOC ratio developed for each of the segments in the 2011 Gas Composition Memorandum.

Table 5-4. Estimated Annual Reciprocating Compressor Emission Reductions from Increasing the Frequency of Rod Packing Replacement

Oil and Natural Gas Segment	Individual Compressor Emission Reductions (tons/compressor-year)	
	Methane	VOC
Gathering and Boosting	6.84	1.9
Processing	17.58	4.89

Cost Impacts

Costs for the specified frequency of replacement of reciprocating compressor rod packing documented in the 2011 NSPS TSD were obtained from a Natural Gas STAR Lessons Learned document which estimated the cost to replace the packing rings to be $1,712 per cylinder (converted from 2008 dollars to 2012 dollars). It was assumed that rod packing replacement would occur during planned shutdowns and maintenance and, therefore, no additional travel costs would be incurred for implementing the rod packing replacement program. In addition, no costs were included for monitoring because the rod packing replacement is based on the number of hours that the compressor operates or the period of time since the previous replacement. The 2011 NSPS TSD analysis assumed that, at baseline, the replacement of rod packing for reciprocating compressors occurs on average every four years based on industry information from the Natural Gas STAR Program. The cost impacts are based on the replacement frequency of the rod packing every 26,000 hours that the reciprocating compressor operates in the pressurized mode.

The 26,000 hour replacement frequency used for the cost impacts in the 2011 NSPS TSD was determined using a weighted average of the annual percentage that the reciprocating compressors are pressurized. The weighted average percentage was calculated to be 98.9 percent. This percentage was multiplied by the total number of hours in 3 years to obtain a value of 26,000 hours. Assuming an interest rate of 7 percent, the capital recovery factors (based on replacing the rod packing every 3 years or 26,000 hours) were calculated to be 0.3122 and 0.3490 for gathering and boosting stations and the processing segment, respectively. The capital costs were calculated using the average rod packing cost of $1,712 (converted from $1,620 in 2008 dollars to 2012 dollars) and the average number of cylinders per compressor (assumed to be 3.3 cylinders for gathering and boosting stations and 2.5 cylinders for processing segment compressors).[51] The annual costs were calculated using the capital costs and the capital recovery factors. Table 5-5 presents a summary of the capital and annual costs for gathering and boosting stations and the processing segment.

There are monetary savings associated with the amount of gas saved with reciprocating compressor rod packing replacement. Monetary savings associated with the amount of gas saved with reciprocating compressor rod packing replacement was estimated using a natural gas price of $4.00 per Mcf.[52] Table 5-5 presents the annual costs with savings and cost of control for reciprocating rod packing replacement for gathering and boosting stations and the processing segment.

Reciprocating compressor rod packing replacement prevents the escape of natural gas from the piston rod. In addition to reducing VOC emissions, there would be a co-benefit of reducing other emissions (such as methane) as a result of increasing the frequency of rod packing replacement.

Table 5-5. Cost of Control for Increasing the Frequency of Reciprocating Compressor Rod Packing Replacement

Oil and Gas Segment	Capital Cost ($2012)[a]	Annual Costs per Compressor ($/compressor-year)		VOC Cost of Control ($/ton)	
		Without Savings	With Savings	Without Savings	With Savings
Gathering and Boosting	$5,650	$2,153	$566	$1,131	$298
Processing	$4,280	$1,631	($2,443)	$334	($500)

[a] 2011 TSD 2008 dollars converted to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflater (5.69 percent).

[51] 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 Document Number EPA-453/R-11-002.
[52] U.S. Energy Information Administration. *Annual U.S. Natural Gas Wellhead Price. U.S. Energy Information Administration Natural Gas Navigator*. Retrieved online on December 12, 2010 at http://www.eia.doe.gov/dnav/ng/hist/n9190us3a.htm.

Frequency of Replacement and/or Realignment/Retrofitting of the Piston Rod

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.[53] 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. We assume that operators will choose, at their discretion, when to replace/realign or retrofit the rod as part of regular maintenance procedures and replace the rod when appropriate when the compressor is out of service for other maintenance such as rod packing replacement. Therefore, we did not consider this option any further.

Updated Rod Packing Material

Although specific analyses have not been conducted, there may be potential for reducing VOC emissions by updating rod packing components made from newer materials, which can help improve the life and performance of the rod packing system. One option is to replace the bronze metallic rod packing rings with longer lasting carbon-impregnated Teflon rings. Compressor rods can also be coated with chrome or tungsten carbide to reduce wear and extend the life of the piston rod.[54] Although changing the rod packing material has been identified as a potential VOC emission reduction option for reciprocating compressors, there is insufficient information on its emission reduction potential and use throughout the industry.

Economic Rod Packing Replacement

Another option facilities can use that has the potential to reduce costs and emissions is for facilities to use specific financial objectives and monitoring data to determine emission levels at which it is cost-effective to replace rings and rods. Benefits of calculating and utilizing this "economic replacement threshold" include VOC emission reductions and natural gas cost savings. Using this approach, one Natural Gas STAR partner reportedly achieved savings of over

[53] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR Program. 2006.
[54] Ibid.

$233,000 annually at 2006 gas prices. An economic replacement threshold approach would also result in operational benefits, including a longer life for existing equipment, improvements in operating efficiencies, and long-term savings.[55]

Gas Recovery (Routing of Emissions to a Process)

Description

Another control option for reciprocating compressors includes control techniques that recover natural gas leaking past the piston rod packing. We are aware of a system that captures the natural gas that would otherwise be vented and routes it back to the compressor engine to be used as fuel.[56] The vent gases are passed through a valve train that includes a demister and then are injected into the engine intake air after the air filter. In general, the technology consists of recovering vented emissions from the rod packing under negative pressure and routing these emissions of otherwise vented gas to the air intake of a reciprocating internal combustion engine that would burn the gas as fuel to augment the normal fuel supply. The system's computerized air/fuel control system would then adjust the normal fuel supply to accommodate the increased fuel made available from the recovered emissions and thereby take advantage of the recovered emissions while avoiding an overly rich fuel mixture.

Subpart OOOO, as well as subpart OOOOa, provide a compliance option for reciprocating compressors that allows collecting emissions from the rod packing using a rod packing emissions collection system which operates under negative pressure and routing the rod packing emissions to a process through a closed vent system. Both of the above systems, if installed using a cover and closed vent system meeting the subpart OOOO and subpart OOOOa requirements, could potentially be used for this compliance option.

Control Effectiveness

One estimate obtained by the EPA states that the gas recovery system can result in the elimination of over 99 percent of VOC emissions that would otherwise occur from the venting of the emissions from the compressor rod packing.[57] The emissions that would have been vented are combusted in the compressor engine to generate power.

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[55] Ibid.

[56] REM Technology Inc. and Targa Resources. *Reducing Methane and VOC Emissions*. Presentation for the 2012 Natural Gas STAR Annual Implementation Workshop.

[57] REM Technology Inc., et al. *Profitable Use of Vented Emission in Oil & Gas Production*. Prepared with support from the Climate Change and Emissions Management Corporation (CCEMC). 2013.

If the facility is able to route rod packing vents to a VRU system, it is possible to recover approximately 95-100 percent of emissions. If the gas is routed to a flare, approximately 95 percent of the VOC emissions could be reduced.

Cost Impacts

One estimate reported that the cost per engine would be approximately $12,000 (does not include installation costs). Some costs would be mitigated by fuel gas savings, as using the captured gas to displace some of the purchased fuel would require less fuel to be purchased in order to run the compressor engine. The fuel cost saving based on a 4-throw compressor with moderate leak rate would be an estimated $6,500 per year.[58] This technique is discussed further in the Natural Gas STAR PRO Fact Sheet titled "Install Automated Air/Fuel Ratio Controls".[59] This document reported an average fuel gas savings of 78 Mcf/day per engine with the gas recovery system installed. Based on our review of information on this technology, we conclude that this technology has merit and would provide better emission reductions than increasing the replacement of rod packing from every 4 years to every 3 years since the emissions would be captured under negative pressure, allowing all emissions to be routed to the engine. It is our understanding that this technology may not be applicable to every compressor installation and situation.

For a VRU, assuming the proper equipment is already available at the facility, capturing the rod packing emissions would require minimal costs. The investment would only need to include the cost of piping and installation. While we have not obtained a cost estimate specifically for routing rod packing vents to a VRU, this process has been studied for dehydrators and would be similar for rod packing systems. According to the Natural Gas STAR PRO Fact Sheet titled "Pipe Glycol Dehydrator to Vapor Recovery Unit,"[60] the cost for planning and installing additional piping is approximately $2,000. Routing to a VRU also provides additional incentive as there is a value associated with recovered gas. However, the installation of a VRU to only capture rod packing emissions may not be economically viable if an additional compressor system is required. If the VRU is already present at the facility, the incremental cost

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[58] REM Technology Inc. Presentation to the U.S. Environmental Protection Agency on December 1, 2011. EPA Docket ID No. EPA-HQ-OAR-2010-0505.

[59] U.S. Environmental Protection Agency. Gas STAR PRO No. 104. *Install Automated Air/Fuel Ratio Controls*. 2011.

[60] U.S. Environmental Protection Agency. Gas STAR PRO No. 203. *Pipe Glycol Dehydrator to Vapor Recovery Unit*. 2011.

to capture the rod packing vent gas can be recovered from the value of the additional captured natural gas.

Although gas recovery has been identified as a potential VOC emission reduction option for reciprocating compressors, there is insufficient information on its availability as a reasonably available control option for reducing reciprocating compressor VOC emissions. However, we recommend that air agencies consider this technology as a compliance option when considering the RACT recommendations presented in section 5.4 of this chapter.

5.3.1.2 Centrifugal Compressors Equipped with Wet Seals

Potential control options to reduce emissions from centrifugal compressors equipped with wet seals include control techniques that limit the leaking of natural gas across the rotating shaft, and capture and destruction of the emissions by routing emissions to a process (e.g., a compressor or fuel gas system) or to a combustion device (discussed in detail in sections 4.3.1.2 of chapter 4). We evaluate below three available control options: (1) converting wet seals to dry seals, (2) routing emissions to a fuel gas system or compressor (process), and (3) routing emissions to a combustion device.

Converting Wet Seals to Dry Seals

Description

We evaluated the use of centrifugal compressor dry seals as an available VOC control option for wet seal centrifugal compressors. As noted in section 5.2 of this chapter, the VOC emission profile from the use of dry seals is considerably less than from the use of wet seals. Replacing wet seals with dry seals can, therefore, substantially reduce VOC emissions across the rotating shaft compared to wet seals, while simultaneously reducing operating costs and enhancing compressor efficiency compared to wet seals. During normal operation, dry seals leak at a rate of 6 scfm methane per compressor.[61] 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 recirculated is usually vented to the atmosphere,

[61] U.S. Environmental Protection Agency. Lessons Learned Document. *Replacing Wet Seals with Dry Seals in Centrifugal Compressors*. October 2006.

bringing the total leakage rate for tandem wet seals to 47.7 scfm methane per compressor.[62,63] It is not practical or feasible in all situations, however, to retrofit an existing wet seal compressor with a dry seal compressor. We have received information that indicates that the conversion process requires a significant period of time to complete and the compressor would need to be out of commission for the conversion period.

Control Effectiveness

The emission reductions that would occur by replacing wet seal compressors with a dry seal compressor were calculated by subtracting the dry seal emissions from the emissions from a centrifugal compressor equipped with wet seals. We used the centrifugal compressor emission factors in Table 5-2 and estimated that VOC emissions would be reduced by 16.7 tpy per compressor.

Cost Impacts

The Natural Gas STAR Program estimated the cost of retrofitting dry seals on a centrifugal compressor equipped with wet seals to be $324,000 ($342,439 in 2012 dollars) for a two-seal dry seal system, which includes the cost of both seals and the dry gas conditioning, monitoring, control console and installation.[64] The annual costs were calculated as the capital recovery of the capital cost assuming a 20-year equipment life and 7 percent interest, which is approximately $32,324 per compressor. The Natural Gas STAR Program estimated that the annual operation and maintenance savings from the installation of a dry seal compressor is $88,300 ($93,325 in 2012 dollars) in comparison to a wet seal compressor. In addition, the installation of dry seals reduces natural gas emissions by 10,721 Mscf/yr[65] which results in an estimated natural gas savings of $42,883 per year assuming a natural gas price of $4/Mcf. A summary of the capital and annual costs for replacing a wet seal compressor with a dry seal compressor is presented in Table 5-6 along with the VOC cost of control. As noted above, we

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[62] U.S. Environmental Protection Agency, et al. *Methane's Role in Promoting Sustainable Development in the Oil and Natural Gas Industry*. World Gas Conference 10/2009.

[63] U.S Environmental Protection Agency. *Methodology for Estimating CH4 and CO2 Emissions from Natural Gas Systems. Inventory of U.S. Greenhouse Gas Emission and Sinks: 1990-2012*. Washington, DC. Annex 3. Table A-129.

[64] U.S. Environmental Protection Agency. Lessons Learned Document. *Replacing Wet Seals with Dry Seals in Centrifugal Compressors*. October 2006.

[65] The natural gas savings was calculated by using the 16.7 tpy VOC reduction and dividing by the VOC/methane weight ratio of 0.278 to determine the amount of methane reduction that would be reduced (60.1 tpy). The methane emission reductions were converted to volumetric natural gas reductions assuming a natural gas density of 0.02082 tons/Mcf and an 82.9 volume percent conversion factor of methane to natural gas.

have received information that indicates that the conversion process requires a significant period of time to complete and the compressor would need to be out of commission during the conversion period. Because of this, a facility may have to provide a temporary compressor in the interim that would add additional costs to the cost estimates we present in Table 5-6.

Table 5-6. Cost of Control of Replacing a Wet Seal Compressor with a Dry Seal Compressor

Oil & Natural Gas Segment	Capital Cost ($2012)	Annual Costs Per Compressor ($/compressor-year)		VOC Cost of Control ($/ton)	
		Without Savings [a]	With O&M and Natural Gas Savings [b]	Without Savings	With O&M and Natural Gas Savings
Processing	$342,439	$32,324	($103,884)	$1,931	($6,205)

[a] Includes only the annualized capital cost of the retrofit of the dry seal system (20 years, 7 percent interest).
[b] Includes the annualized capital cost, annual operation and maintenance (O&M) savings and annual natural gas savings.

Routing Emissions to a Compressor or Fuel Gas System (Process)

Description

One option for reducing VOC emissions from the compressor wet seal fluid degassing system is to route the captured emissions back to the compressor suction or fuel system or other beneficial use (referred to collectively as routing to a process). Routing to a process would entail routing emissions via a closed vent system to any enclosed portion of a process unit (e.g., compressor or fuel gas system) where the emissions are predominantly recycled, consumed in the same manner as a material that fulfills the same function in the process, transformed by chemical reaction into materials that are not regulated materials, incorporated into a product, or recovered. Emissions that are routed to a process can result in the same or greater emission reductions as would have been achieved had the emissions been routed through a closed vent system to a combustion device. Table 5-7 presents a summary of the estimated emission reductions from routing emissions from the wet seal fluid degassing system to a process. For purposes of this analysis, we assume that routing VOC emissions from a wet seal fluid degassing system to a process reduces VOC emissions greater than or equal to a combustion device (i.e., greater than or equal to 95 percent).

Table 5-7. Estimated Annual Centrifugal Compressor VOC Emission Reductions for Routing Wet Seal Fluid Degassing System to a Process[66,67]

Oil & Gas Segment	Individual Compressor VOC Emission Reductions (tons/compressor-year)
Processing	$\geq$ 18.1

Cost Impacts

The capital cost of a system to route the seal oil degassing system to a process is estimated to be $23,252,[68] converting to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflater (Change in GDP: Implicit Price Deflator from 2008 to 2012 (5.69 percent)).[69] The estimated costs include an intermediate pressure degassing drum, new piping, gas demister/filter, and a pressure regulator for the fuel line. The annual costs were estimated to be $2,553 assuming a 15-year equipment life at 7 percent interest.

Potential natural gas savings for this option were estimated to be 12 Mcf/yr and assumes that greater than or equal to 95 percent of the 47.7 scfm methane emissions are controlled, an annual operating factor of 43.6 percent, and the 82.9 volume percent conversion factor of methane to natural gas. Assuming a natural gas savings of $4/Mcf, the natural gas savings equates to approximately $47,553 per year. Table 5-8 presents a summary of the cost of control for routing emissions to a process.

[66] 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 the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.
[67] Ibid.
[68] Ibid.
[69] U.S. Bureau of Economic Analysis. *Gross Domestic Product: Implicit Price Deflator (GDPDEF]*, retrieved from FRED, Federal Reserve Bank of St. Louis. https://research.stlouisfed.org/fred2/series/GDPDEF/ March, 26, 2015.

Table 5-8. VOC Cost of Control for Routing Wet Seal Fluid Degassing System to a Process[a]

Oil and Gas Segment	Capital Cost ($2012)[a]	Annual Costs per Compressor ($/compressor-year)		VOC Cost of Control ($/ton)	
		Without Savings	With Savings	Without Savings	With Savings
Processing	$23,252	$2,553	($47,553)	$141	($2,621)

[a] 2011 TSD 2008 dollars converted to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflater (Change in GDP: Implicit Price Deflator from 2008 to 2012 (5.69 percent)).[70]

Routing Emissions to a Combustion Device

Description

Combustion devices are commonly used in the oil and natural gas industry to combust VOC emission streams. Typical combustion devices used in the oil and natural gas industry to control VOC emissions and their control efficiency are discussed in greater detail in section 4.3.1.2 of chapter 4 of this document. Similar to the analysis of storage vessels, for this analysis, we assumed that the entrained natural gas from the seal oil that is removed in the degassing process would be directed to a combustion device that achieves a 95 percent reduction of VOC. The wet seal emissions in Table 5-2 were used along with the control efficiency to calculate the emission reductions. Table 5-9 presents a summary of the estimated emission reductions from routing emissions from the wet seal to a combustion device.

Table 5-9. Estimated Annual VOC Emission Reductions for Routing Wet Seal Fluid Degassing System to a Combustion Device[71]

Oil & Gas Segment	Individual Compressor VOC Emission Reductions (tons/compressor-year)
Processing	18.1

[70] Ibid.

[71] 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 the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

Cost Impacts

Routing the captured gas from the centrifugal compressor wet seal degassing system to an existing combustion device or installing a new combustion device has associated capital and operating costs. The capital and annual costs of the combustion device (an enclosed flare for the analysis) were calculated using the methodology in the EPA Control Cost Manual.[72] The heat content of the gas stream was calculated using information from the 2011 Gas Composition Memorandum. Table 5-10 presents a summary of the capital and annual costs for wet seals routed to a flare, as well as the VOC cost of control. There is no cost savings estimated for this option because the recovered natural gas is combusted.

Table 5-10. Cost of Control for Routing Wet Seal Fluid Degassing System to a Combustion Device

Industry Segment	Capital Cost ($)		Annual Cost per Compressor ($/compressor-year)		VOC Cost of Control New CD ($/ton)	VOC Cost of Control Existing CD ($/ton)
	New CD	Existing CD	New CD	Existing CD		
Processing	$71,783	$23,252	$114,146	$3,311	$6,292	$183

CD = Control Device

5.3.2 Existing Federal, State and Local Regulations

5.3.2.1 Federal Regulations that Specifically Require Control of VOC Emissions

Under the 2012 NSPS and 2016 NSPS, reciprocating compressors are required to limit VOC emissions by replacing the rod packing on or before 26,000 hours of operation or 36 months since the previous rod packing replacement. Alternatively, an owner or operator is allowed to route rod packing emissions to a process through a closed vent system under negative pressure. For centrifugal compressors in the processing segment, the 2012 NSPS and 2016 NSPS require that VOC emissions be reduced from each centrifugal compressor wet seal fluid degassing system by 95 percent.

[72] U.S. Environmental Protection Agency. *OAQPS Control Cost Manual: Sixth Edition* (EPA 452/B-02-001). Research Triangle Park, NC.

5.3.2.2 State and Local Regulations that Specifically Require Control of VOC Emissions

States may have permitting restrictions on VOC emissions that may apply to an emissions source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met and, often, how the source must be operated. To ensure that sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

Montana requires oil and natural gas well facilities to control emissions from the time the well is completed until the source is registered or permitted. Each piece of oil or natural gas well facility equipment, with VOC vapors of 200 Btu/scf or more with a PTE greater than 15 tpy, is required to (1) capture and route emissions to a natural gas pipeline, (2) route to a smokeless combustion device equipped with an electronic ignition device or a continuous burning pilot system meeting the requirements of 40 CFR 60.18 and operating at 95 percent or greater control efficiency, or (3) route to air pollution control equipment with equal or greater control efficiency than a smokeless combustion device. This includes the control of emissions from compressor engines used for transmission of natural gas (Registration of Air Contaminant Sources, Rule 17.8.1711 Oil or Gas Well Facilities Emission Control Requirements).

Colorado (Regulation 7, XVII.B.3.b and c) requires that uncontrolled actual hydrocarbon emissions from wet seal fluid degassing systems on wet seal centrifugal compressors be controlled by at least 95 percent, unless the centrifugal compressor is subject to 40 CFR part 60, subpart OOOO. Additionally, Regulation 7 requires that rod packing on any reciprocating compressor located at a natural gas compressor station be replaced every 26,000 hours of operation or every 36 months, unless the reciprocating compressor is subject to 40 CFR part 60, subpart OOOO.

5.4 Recommended RACT Level of Control

For reciprocating compressors, there are federal and state regulations that require the periodic replacement of reciprocating compressor packing. The federal regulations (the 2012 NSPS and 2016 NSPS) require the replacement of reciprocating compressor rod packing every 3 years or on or before 26,000 hours of operation. The state regulation (Colorado) requires the replacement of reciprocating compressor rod packing every 26,000 hours of operation or every 36 months. The 2012 NSPS and 2016 NSPS also provide the alternative of routing rod packing emissions to a process via a closed vent system under negative pressure.

As noted in section 5.3 of this chapter, the most significant volume of VOC emissions are associated with piston rod packing systems. We found that, under the best conditions, regular rod packing replacement, when carried out approximately every three years, effectively controls emissions and helps prevent excessive rod wear. The cost of control for requiring the replacement of reciprocating packing at this frequency was estimated to be $1,132 per ton of VOC reduced without savings and $298 per ton of VOC reduced considering savings for gathering and boosting station compressors, and about $334 per ton of VOC reduced without savings, and an overall net savings per ton of VOC reduced for processing segment reciprocating compressors considering savings. Based on the emission reductions, costs (considering gas savings) and existing and currently implemented regulations that require the replacement of the reciprocating compressor packing every 36 months or on or before 26,000 hours of operation, we recommend this control option as RACT for reciprocating compressors in the production and processing segments (excluding compressors at the well site). We also recommend that air agencies provide operators the compliance alternative of routing rod packing emissions to a process via a closed vent system under negative pressure.

For centrifugal compressors, there are already federal, state and local regulations that require the capture and 95 percent control of emissions from wet seal fluid degassing systems from centrifugal compressors. Although dry seal systems have low VOC emissions and the option of routing to a process has at least a 95 percent control efficiency, the replacement of wet seals with dry seals and routing to a process may not be technically feasible or practical options for some centrifugal compressors. The integration of a centrifugal compressor into an operation may require a certain compressor size or design that is not available in a dry seal model, and, in the case of capture of emissions with routing to a process, there may not be downstream equipment capable of handling a low-pressure fuel source. As a result of our evaluation of the technical feasibility and practicality of existing available controls, we recommend RACT be 95 percent control of emissions from the wet seal degassing system, which can be achieved by using a closed vent system and routing emissions to a combustor or routing the emissions back to the compressor or fuel line (routing to the process). For the processing segment, we assume that there is an existing combustion device onsite and the estimated cost of control would be about $183 per ton of VOC reduced for facilities to route emissions to the existing combustion device, or about $141 per ton of VOC reduced for facilities to route the captured emissions back to the compressor or fuel line.

In summary, we recommend the following as RACT for compressors:

(1) RACT for Reciprocating Compressors Located Between the Wellhead and Point of Custody Transfer to the Natural Gas Transmission and Storage Segment (Excludes the Well Site): We recommend that each reciprocating compressor reduce VOC emissions by replacing the rod packing on or before 26,000 hours of operation or 36 months since the last rod packing replacement. We also recommend that an alternative be provided to allow routing of rod packing emissions to a process via a closed vent system under negative pressure in lieu of the specified rod packing replacement periods. We do not recommend that RACT apply to individual reciprocating compressors located at a well site, or an adjacent well site and servicing more than one well site.

(2) RACT for Centrifugal Compressors Using Wet Seals Located Between the Wellhead and Point of Custody Transfer to the Natural Gas Transmission and Storage Segment (Excludes the Well Site): We recommend that each centrifugal compressor using wet seals reduce VOC emissions from each wet seal fluid gassing system by reducing VOC emissions by 95 percent. We do not recommend that RACT apply to individual centrifugal compressors using wet seals located at a well site, or an adjacent well site and servicing more than one well site.

5.5 Factors to Consider in Developing Compressor Compliance Procedures

5.5.1 Reciprocating Compressor Compliance Recommendations

In order to ensure and demonstrate compliance with the recommended RACT for reciprocating compressors, we recommend that air agencies require facilities to maintain a record of the date of the most recent reciprocating compressor rod packing replacement, monitor and keep records of the number of hours of operation and/or track the number of months since the last rod packing replacement for each reciprocating compressor (to meet the requirement that the packing is changed out on or before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months) and maintain records of instances where the reciprocating compressor was not operated in compliance with RACT. This may require the installation of an operating hours meter on the engine to track the number of hours of operation. We also recommend that air agencies require annual reports of the cumulative hours of operation or number of months since packing replacement for each reciprocating compressor and instances when there were deviations where the reciprocating compressor was not operated in compliance with the recommended RACT.

For applications in which operators choose to opt for the alternative of routing of rod packing emissions to a process via a closed vent system under negative pressure, it is recommended that air agencies require facilities to maintain records of the date of installation of a rod packing emissions collection system and closed vent system and maintain records of instances of deviations in cases where the reciprocating compressor was not operated in compliance with requirements. We also recommend that air agencies require annual reports for each reciprocating compressor complying with this option indicating when there were deviations where the reciprocating compressor was not operated in compliance with the recommended RACT. Recommended cover and closed vent system design and operation measures are specified in sections 5.5.3 and 5.5.4.

The appendix to this document presents example model rule language that incorporates compliance elements recommended in this section that air agencies may choose to use in whole or in part.

5.5.2 Centrifugal Compressor Equipped with a Wet Seal Recommendations

In order to ensure that VOC emissions are reduced by at least 95 percent (the recommended RACT level of control) from a centrifugal compressor equipped with a wet seal when using a control device or other control measure (such as routing to a process), the centrifugal compressor should be equipped with a cover that is connected through a closed vent system that routes emissions to the control device (or process) that meets the RACT level of control. Recommended cover and closed vent system design and operation measures are specified in sections 5.5.3 and 5.5.4. Recommended control device operation and monitoring provisions for specified controls to ensure compliance are presented in section 5.5.5.

The appendix of this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part.

5.5.3 Recommendations for Cover Design

The cover and all openings on the cover should form a continuous impermeable barrier over the entire surface area of the liquid in the wet seal fluid degassing system (for centrifugal compressors), and of the rod packing emissions collection system (for reciprocating compressors). Each cover opening should be secured in a closed, sealed position (e.g., covered by a gasketed lid or cap) except during those times when it is necessary to use an opening as follows:

(1) To inspect, maintain, repair, or replace equipment; or

(2) To vent gases or fumes from the unit, through a closed vent system designed and operated in accordance with closed vent system requirements (see section 5.5.4), to a control device or to a process.

It is recommended that air agencies require olfactory, visual and auditory inspections of covers for defects that could result in air emissions on a monthly basis. We recommend air agencies require that any detected defects be repaired as soon as practicable.

5.5.4 Recommendations for Closed Vent Systems

The closed vent system should be designed and operated with no detectable emissions (using a 500 ppm detection level, as measured using Method 21 of appendix A-7 of Part 60, and ongoing monthly olfactory, visual and auditory inspections). It is recommended that air agencies require that any detected defects be repaired as soon as practicable.

With the exception of low leg drains, high point bleeds, analyzer vent, open-ended valves and safety devices, if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process, air agencies should require that owners or operators either:

(1) Install, calibrate, maintain and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings and either sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open

such that the stream is being, or could be, diverted away from the control device or process to the atmosphere; or

(2) Secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

5.5.5 Recommendations for Control Device Operation and Monitoring

If a control device is used to comply with the recommended 95 percent VOC emission reduction RACT level of control, we advise that the device be required to operate at all times when gases, vapors, and fumes are vented from the wet seal fluid degassing system through the closed vent system to the control device. The following paragraphs present select emission control options and suggested operation and monitoring requirements, as appropriate to ensure compliance with the recommended RACT level of control.

Enclosed Combustion Devices

If an enclosed combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) is used to meet the 95 percent VOC emission reduction RACT level of control, it should be designed to reduce the mass content of VOC emissions by 95 percent or greater and be: (1) maintained in a leak free condition, (2) installed and operated with a continuous burning pilot flame, and (3) operated with no visible emissions.

It is recommended that the visible emissions test (using section 11 of EPA Method 22, 40 CFR part 60, appendix A-7) be performed at least once every calendar month. If a combustion device fails the visible emissions test, sources should be required to follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. It is recommended that all inspection, repair and maintenance activities for each unit be recorded in a maintenance and repair log that can be made available for inspection. Following return to operation from maintenance or repair activity, each device should be required to pass a Method 22, 40 CFR part 60, appendix A-7 visual emissions test.

It is recommended that air agencies require that sources meeting the 95 percent VOC emission reduction RACT level of control by routing emissions to a combustion device conduct performance tests and/or design analyses that demonstrate that the combustion device being used meets the required 95 percent VOC emission reduction RACT level of control (see section F of the appendix to this document for performance testing procedures for control devices that we recommend be used to demonstrate performance requirements).

Routing to a Process

Routing to a process would entail routing emissions via a closed vent system to any enclosed portion of a process unit where the emissions are predominantly recycled, consumed in the same manner as a material that fulfills the same function in the process, transformed by chemical reaction into materials that are not regulated materials, incorporated into a product, or recovered. Vapor recovery units and flow lines that “route emissions to a process” would be considered part of the process and would not be considered control devices that are subject to standards, but the recommended cover and closed vent system design, operation and monitoring requirements specified in sections 5.5.3 and 5.5.4 would apply.

6.0 PNEUMATIC CONTROLLERS

The oil and 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 pneumatic devices used throughout the oil and natural gas industry as part of the instrumentation to control the position of valves and may be actuated using pressurized natural gas (natural gas-driven) or may be actuated by another means such as a pressurized gas other than natural gas, solar, or electric. This chapter describes pneumatic controllers that are used in the oil and natural gas industry, including their function and associated emissions. This chapter also presents control techniques used to reduce VOC emissions from these pneumatic controllers, along with costs and emission reductions. Finally, this chapter discusses our recommended RACT and the associated VOC emission reductions and costs for pneumatic controllers.

6.1 Applicability

For the purposes of this CTG, a pneumatic controller is an automated instrument used to maintain a process condition such as liquid level, pressure, pressure differential and temperature. The emissions and emission controls discussed herein would apply to natural gas-driven pneumatic controllers in the oil and natural gas industry located from the wellhead to a natural gas processing plant (including the natural gas processing plant) or from the wellhead to the point of custody transfer to an oil pipeline.

6.2 Process Description and Emission Sources

6.2.1 Process Description[73]

Natural gas-driven pneumatic controllers come in a variety of designs for a variety of uses. For the purposes of this CTG, they are characterized primarily by their emission characteristics:

(1) *Continuous bleed pneumatic controllers* are used to modulate flow, liquid level, or pressure, and gas is vented continuously at a rate that may vary over time. Continuous bleed controllers are further subdivided into two types based on their bleed rate:

   a. *Low-bleed*, having a bleed rate of less than or equal to 6 standard cubic feet per hour (scfh).

   b. *High-bleed*, having a bleed rate of greater than 6 scfh.

(2) *Intermittent bleed or snap-acting pneumatic controllers* release gas only when they open or close a valve or as they throttle the gas flow.

(3) *Zero-bleed pneumatic controllers* do not bleed natural gas to the atmosphere. These natural gas-driven pneumatic controllers are self-contained devices that release gas to a downstream pipeline instead of to the atmosphere.

Pneumatic controllers often make use of available high-pressure natural gas to operate or control a valve. The supply gas pressure is modulated by a process condition, and then flows to the valve controller where the signal is compared with the process set point to adjust gas pressure in the valve actuator. In these natural gas-driven pneumatic controllers, natural gas may be released intermittently with every actuation of the valve. In other designs, natural gas may be released 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. It is our understanding that self-contained devices that release natural gas to a downstream pipeline instead of to the atmosphere have no emissions. “Closed loop” systems are applicable only in instances with very low pressure[74] and may not be suitable to

[73] U.S. Environmental Protection Agency. *Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

[74] Memorandum to Bruce Moore, U.S. Environmental Protection Agency, from Denise Grubert, EC/R Incorporated. *Meeting Minutes from EPA Meeting with the American Petroleum Institute (API)*. October 2010.

replace many applications of continuous or intermittent bleed pneumatic devices. Therefore, this CTG does not address these self-contained devices further.

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 the total emissions are dependent on the application in which they are used, we do not consider their use to be a technically practical control option for all continuous bleed controllers.

As previously indicated, not all pneumatic controllers are natural gas driven. At sites with a continuous and reliable source of electricity, controllers can be actuated by an instrument air system that uses compressed air instead of natural gas. These sites may also use mechanical or electrically powered pneumatic controllers. In some instances, solar-powered controllers may be feasible. Because these devices are not natural gas driven, they do not directly release natural gas or VOC. 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. To our knowledge, natural gas processing plants are the only facilities in the oil and natural gas industry that are likely to have electrical service sufficient to power an instrument air system, and most existing natural gas processing plants use instrument air instead of natural gas-driven devices.[75]

[75] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices*. EPA-600/R/-96-080k. June 1996.

6.2.2 Emissions Data

6.2.2.1 Summary of Major Studies and Emissions

In the evaluation of the emissions from pneumatic controllers and the potential options available to reduce VOC emissions, numerous studies were consulted. Table 6-1 lists these references with an indication of the type of relevant information contained in each reference. In addition to these sources, we evaluated the peer reviewer and public comments received on the EPA's white paper, "Oil and Natural Gas Sector Pneumatic Devices."[76]

Table 6-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[l]
Greenhouse Gas Reporting Program (Annual Reporting; Current Data Available for 2011-2013)[a]	EPA	2014	Facility-Level	X	X
Inventory of Greenhouse Gas Emissions and Sinks[b]	EPA	Annual	Nationwide/ Regional	X	
Methane Emissions from the Natural Gas Industry[c]	EPA/GRI	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry[d]	EPA/GRI	1996	Nationwide	X	
Methane Emissions from the U.S. Oil Industry[e]	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States[f]	WRAP	2005	Regional	X	
Natural Gas STAR Program[g]	EPA	2000 – 2010	Voluntary	X	X
Measurements of Methane Emissions from Natural Gas Production Sites in the United States[h]	Multiple Affiliations, Academic and Private	2013	Nationwide	X	

[76] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Pneumatic Devices*. *Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel*. Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415pneumatic.pdf.

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[l]
Determining Bleed Rates for Pneumatic Devices in British Columbia[i]	The Prasino Group	2013	British Columbia	X	
Air Pollutant Emissions from the Development, Production, and Processing of Marcellus Shale Natural Gas[j]	Carnegie Mellon University	2014	Regional (Marcellus Shale)	X	
Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries[k]	ICF International	2014	Nationwide	X	X

[a] U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC.
[b] U.S Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html.
[c] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 2: Technical Report.* EPA-600/R-96-080b. June 1996; U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 3: General Methodology*. EPA-600/R-96-080c. June 1996; U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 5: Activity Factors*. EPA-600/R-96-080e. June 1996; and U.S. Environmental Protection Agency. *Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices*. EPA-600/R-96-080k. June 1996.
[d] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the U.S. Petroleum Industry. Draft Report*. June 14, 1996.
[e] ICF Consulting. *Estimates of Methane Emissions from the U.S. Oil Industry*. Prepared for the U.S. Environmental Protection Agency. 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. Environmental Protection Agency. *Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR. Washington, DC. October 2006.
[h] 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.
[i] U.S. Environmental Protection Agency. *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas Star. Washington, DC. 2006.
[j] 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.
[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.

[1] An “X” in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

6.2.2.2 Representative Pneumatic Controller Device Emissions

For purposes of this CTG, continuous bleed pneumatic controllers are 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 scfh, while low-bleed devices bleed at a rate less than or equal to 6 scfh.[77]

In support of the development of the 2012 NSPS and 2016 NSPS, and this CTG, we consulted information in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic devices, subpart W of the GHGRP, the GHG Inventory, as well as pneumatic controller vendor information used during the development of the 2012 NSPS.[78] The data obtained from vendors included emission rates, costs, and any other pertinent information for each pneumatic controller model (or model family). All pneumatic controllers 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.

Although, by definition, a low-bleed device can emit up to 6 scfh, through vendor research, a 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 bleed rates 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.[79,80] While the vendor data provided 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 in the oil and

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[77] The classification of high-bleed and low-bleed devices originated from a report by Pacific Gas & Electric (PG&E) and the Gas Research Institute (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.

[78] 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 Document Number EPA-453/R-11-002.

[79] U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2010.

[80] All rates are listed at an assumed supply gas pressure of 20 psig.

natural industry, which is an important factor in developing a representative emission factor. Therefore, in support of this CTG, we have determined that the best available emission estimates for pneumatic controllers in the production segment are from the GHGRP. For the natural gas processing segment, we determined that the quantified representative methane emissions from a continuous bleed pneumatic controller based on natural gas emission rates presented in Volume 12 of the EPA/GRI report used in the 2012 NSPS TSD is the best available emissions information.[81]

The basic approach used for this analysis of emissions from pneumatic controllers was to first approximate the natural gas emissions from an average high-bleed and low-bleed pneumatic controller in the production and processing segments and then estimate methane and VOC emissions using a representative gas composition from the 2011 Gas Composition Memorandum. A bleed rate of 1.39 scfh was used for a low-bleed controller, and a bleed rate of 37.3 scfh was used for a high-bleed controller. The specific gas composition ratio used for the production and processing segments was 0.278 pounds VOC per pound methane. Table 6-2 summarizes the estimated bleed emissions for a representative pneumatic controller by industry segment (for production and processing segments) and device type.

Table 6-2. Average Emission Rates for High-Bleed and Low-Bleed Pneumatic Controllers in the Oil and Natural Gas Industry[a]

Industry Segment	High-Bleed (tpy)		Low-Bleed (tpy)	
	Methane	VOC	Methane	VOC
Oil and Natural Gas Production[b,c]	5.3	1.47	0.2	0.06
Natural Gas Processing[d]	1.00	0.28	1.0	0.28

[a] The conversion factor used in this analysis is 1 Mcf of methane is equal to 0.0208 tons methane.
[b] Natural gas production methane emissions are derived from the GHGRP (subpart W).
[c] Oil production methane emissions are derived from the GHGRP (subpart W). It is assumed only continuous bleed devices are used in oil production.
[d] Natural gas processing segment methane emissions are derived from Volume 12 of the 1996 EPA/GRI report. Emissions from devices in the processing segment were determined based on data available for snap-acting and continuous bleed devices. Further distinction between high-

[81] GRI/EPA Research and Development. Methane Emissions from the Natural Gas Industry; Volume 12: Pneumatic Devices. (1996) EPA-600/R-96-0801. Table 4-11, page 56.

and low-bleed could not be determined based on available data. For the natural gas processing segment, it is assumed that existing natural gas plants have already replaced pneumatic controllers with other types of controls (i.e., an instrument air system) and any high-bleed devices that remain are safety related.

For the natural gas processing segment, this analysis assumes that existing natural gas plants have already replaced pneumatic controllers with other types of controls (i.e., an instrument air system) and any high-bleed devices that remain are safety related.

6.3 Available Controls and Regulatory Approaches

6.3.1 Available VOC Emission Control Options

Although pneumatic controllers have relatively small emissions individually, due to the large population of these devices, the cumulative VOC emissions for the industry are significant. We are not aware of any add-on controls that are or can be used to reduce VOC emissions from gas-driven pneumatic controllers. The following sections provide a summary of options for reducing VOC emissions from pneumatic controllers including: (1) replacing high-bleed controllers with low-bleed controllers or zero-bleed controllers; (2) driving controllers with instrument air rather than natural gas, using non-gas-driven controllers; and (3) enhanced maintenance.

Sections 6.3.1.1 and 6.3.1.2 discuss the control of VOC emissions by replacing a high-bleed device with a low-bleed device, and driving controllers with instrument air rather than natural gas, including the estimated costs of these options. Given applicability, efficiency and the expected costs, other options (i.e., mechanical controls and enhanced maintenance) are only briefly discussed in sections 6.3.1.3 and 6.3.1.4.

6.3.1.1 Install a Low-Bleed Device in Place of a High-Bleed Device

Description

As discussed previously, low-bleed controllers generally provide the same operational function as a high-bleed controller, but have lower continuous bleed emissions.

Control Effectiveness

We estimate on average that 1.41 tons of VOC will be reduced annually per device in the production segment from installing a low-bleed device in place of a high-bleed device. There are certain situations in which replacing and retrofitting devices 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, we assumed about 80 percent of high-bleed devices can be replaced with low-bleed devices throughout the production segment.

Applicability of low-bleed controllers may depend on the function carried out by the controller. Low-bleed pneumatic controllers may not be applicable for replacement of high-bleed devices because a process condition may require a fast or precise control response to minimize deviation from the desired set point. A slower acting low-bleed controller could potentially result in damage to equipment and/or become a safety issue because it may not be able to respond as quickly as a high-bleed controller. An example of this is a compressor where pneumatic controllers may monitor the suction and discharge pressure and actuate a recycle when one or the other is out of the specified target range. Other scenarios for fast and precise control include transient (non-steady state) situations where a gas flow rate may fluctuate widely or unpredictably. This situation requires a responsive high-bleed device to ensure that the gas flow can be controlled in all situations. Temperature and level controllers are typically present in control situations that are not prone to fluctuate as widely or where the fluctuation can be readily and safely accommodated by the equipment. Therefore, such processes can typically accommodate control from a low-bleed device, which is slower acting and less precise.

Cost Impacts

Costs were based on 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 controllers.[82] As Table 6-3 indicates, the average cost for a low-bleed pneumatic controller is $2,698, while the average cost for a high-bleed pneumatic controller is $2,471.[83] In order to analyze cost impacts, the average cost to install a new low-bleed pneumatic controller was annualized for a 15-year period using a 7 percent interest rate. This equates to an annualized cost of around $271 per low-bleed device for the production segment.

[82] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry.* Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.
[83] Costs are estimated in 2012 U.S. dollars.

Table 6-3. Cost Projections for Representative Pneumatic Controllers[a]

Device	Minimum Cost ($2012)	Maximum Cost ($2012)	Average Cost ($2012)
High-Bleed Controller	$387	$7,398	$2,471
Low-Bleed Controller	$554	$9,356	$2,698

[a] 2011 NSPS TSD 2008 dollars converted to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflater (5.69 percent). During the development of the 2012 NSPS, major pneumatic controller vendors were surveyed for costs, emission rates and any other pertinent information.

Monetary savings associated with retaining natural gas that would have been emitted was estimated based on a natural gas value of $4.00 per Mcf.[84] The use of a low-bleed pneumatic controller is estimated to reduce methane emissions by 5.1 tpy (245 Mcf/yr) (using the conversion factor of 0.0208 tons methane per 1 Mcf) over the use of a high-bleed pneumatic controller. Assuming natural gas in the production segment is 82.8 percent methane by volume, this equals 296 Mcf natural gas recovered per year. Therefore, the value of recovered natural gas from one pneumatic controller in the production segment is approximately $1,184. Table 6-4 presents the estimated cost of control per ton of VOC reduced for replacing a high-bleed pneumatic controller with a new low-bleed pneumatic controller in the production segment of the oil and natural gas industry.

Table 6-4. VOC Cost of Control for Replacing an Existing High-Bleed Pneumatic Controller with a New Low-Bleed Pneumatic Controller

Segment	Average Capital Cost per Unit ($2012)[a,c]	Total Annual Costs per Unit ($2012/yr)[b,c]		VOC Cost of Control ($2012/ton)[c]	
		Without Savings	With Savings	Without Savings	With Savings
Oil and Natural Gas Production	$2,698	$296	($886)	$209	($625)

[a] Average capital cost of a low-bleed device as summarized in Table 6-3.
[b] Annualized cost assume a 7 percent interest rate over a 15-year equipment lifetime.
[c] Cost data from the 2011 TSD converted to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflater (5.69 percent).

[84] U.S. Energy Information Administration. *Annual U.S. Natural Gas Wellhead Price. U.S. Energy Information Administration. Natural Gas Navigator*. Retrieved online on 12 Dec 2010 at http://www.eia.doe.gov/dnav/ng/hist/n9190us3a.htm.

6.3.1.2 Instrument Air Systems

Description

The major components of an instrument air conversion project include the compressor, power source, dehydrator and volume tank. The following is a description of each component as described in the Natural Gas STAR document, "Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air":[85]

(1) Compressors used for instrument air delivery are available in various types and sizes, from centrifugal (rotary screw) compressors to reciprocating piston (positive displacement) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system, and the typical bleed rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank. For reliability, a full spare compressor is normally installed. A minimum amount of electrical service is required to power the compressors.

(2) A critical component of the instrument air control system is the power source required to operate the compressor. Since high-pressure natural gas is abundant and readily available, natural 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 in remote locations, however, a reliable source of electric power can be difficult to ensure. In some instances, solar-powered, battery-operated air compressors can be cost-effective for remote locations, and reduce both VOC emissions and energy consumption. Small natural gas-driven fuel cells are also being developed.

(3) Dehydrators, or air dryers, are also 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.

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[85] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. 2006.

(4) 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, such as for a motor starter, pneumatic pump, or pneumatic tools without affecting the process control functions.

Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic controller. The use of instrument air eliminates natural gas emissions from natural gas-driven pneumatic controllers. All other parts of a natural gas pneumatic system will operate the same way with instrument air as they do with natural gas. The conversion of natural gas pneumatic controllers to instrument air systems is applicable to all natural gas facilities with electrical service available. Figure 6-1 illustrates a diagram of a natural gas pneumatic control system. Figure 6-2 illustrates a diagram of a compressed instrument air control system. [86]

Control Effectiveness

The use of instrument air eliminates natural gas emissions from the pneumatic controllers; however, the system is only applicable in locations with access to a sufficient and consistent supply of electrical power. Instrument air systems are also usually installed at facilities where there is access to high Btu gas, a high concentration of pneumatic control valves and the presence of an operator who can ensure the system is properly functioning.[87]

For natural gas processing plants, we believe that instrument air systems are typically used to power pneumatic controllers and that any natural gas-driven pneumatic controllers in use are required for safety and functional reasons. The use of an instrument air system would reduce VOC emissions from a natural gas-driven pneumatic controller by 100 percent.

Cost Impacts

Instrument air conversion requires additional equipment to properly compress and control the pressurized air. The size of the compressor depends on the number of control loops present at a location. A control loop consists of one pneumatic controller and one control valve. The volume of compressed air supply for the pneumatic system is equivalent to the volume of gas

[86] Ibid.
[87] Ibid.

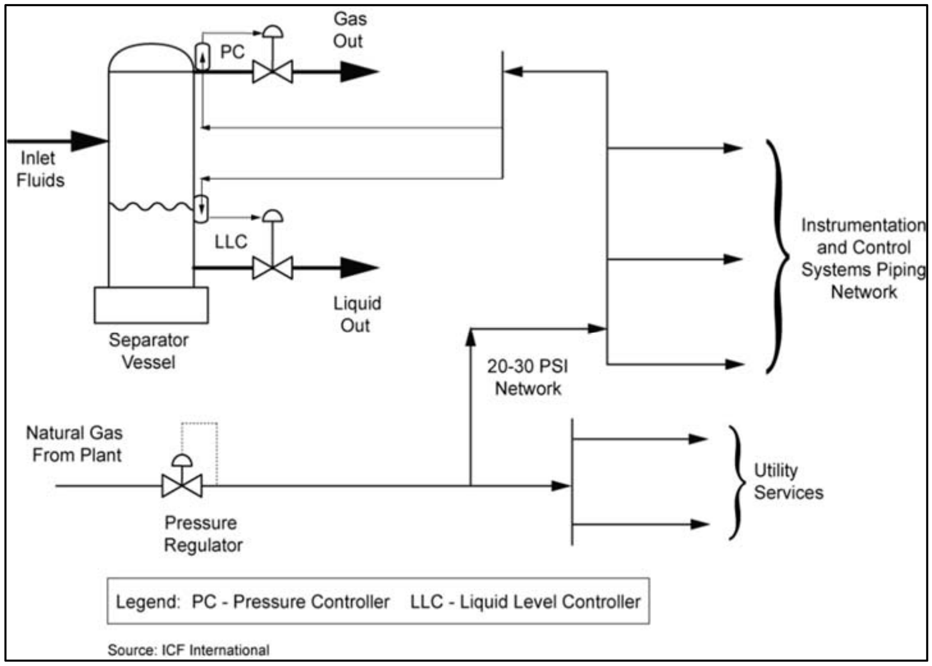

Figure 6-1. Natural Gas Pneumatic Control System

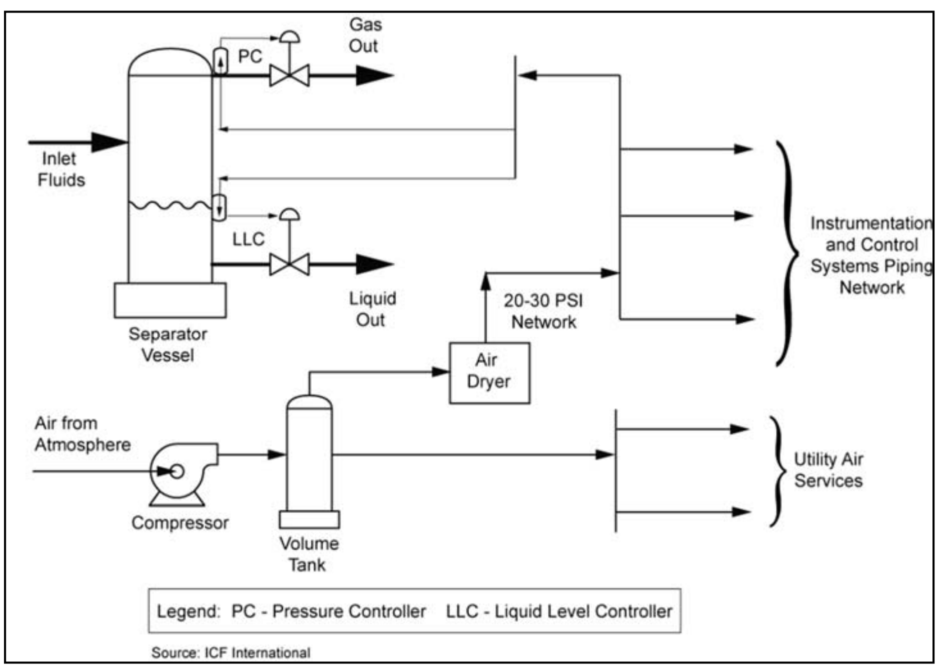

Figure 6-2. Compressed Instrument Air Control System

used to run the existing instrumentation, adjusted for air losses during the drying process. The current volume of gas usage can be determined by direct metering if a meter is installed. Otherwise, an alternative rule of thumb for sizing instrument air systems is one cubic foot per minute (cfm) of instrument air for each control loop. As the system is powered by electric compressors, the system requires a constant source of electrical power and a backup system to operate the controllers in the event of interruption of the electrical supply. Table 6-5 outlines three different sized instrument air systems including the compressor power requirements, the flow rate provided from the compressor, and the associated number of control loops.

Table 6-5. Compressor Power Requirements and Costs for Representative Instrument Air Systems[a]

Compressor Power Requirements[b]			Flow Rate (cfm)	Control Loops (Loops/Compressor)	Power Costs ($/yr)
Size of Unit	Hp	kW			
Small	10	13.3	30	15	$7,758
Medium	30	40	125	63	$23,332
Large	75	100	350	175	$58,329

[a] Based on rules of thumb stated in the Natural Gas STAR document, *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air*. Natural Gas STAR Program. Washington, DC. 2006.
[b] Power is based on the operation of two compressors operating in parallel (each assumed to be operating at full capacity 50 percent of the year).

The primary costs associated with conversion to instrument air systems are the initial capital expenditures for installing compressors and the related equipment and operating costs for electrical energy to power the compressor motor. This equipment includes a compressor, a power source, a dehydrator, gas supply piping, control instruments, valve actuators and a storage vessel. The total cost, including installation and labor, of three representative sizes of compressors were evaluated based on assumptions found in the Natural Gas STAR document, "Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air" and are summarized in Table 6-6.[88]

[88] Ibid.

Table 6-6. Estimated Capital and Annual Costs of Representative Instrument Air Systems ($2012)

Instrument Air System Size	Compressor	Tank	Air Dryer	Total Capital Cost[a]	Annualized Capital Cost[b]	Labor Cost	Total Annual Cost[c]	Annualized Cost of Instrument Air System
Small	$3,987	$797	$2,391	$17,938	$2,554	$1,410	$9,168	$11,722
Medium	$19,928	$2,391	$7,173	$77,716	$11,065	$4,580	$27,912	$38,977
Large	$35,071	$4,783	$15,941	$143,476	$20,428	$6,340	$64,669	$85,097

[a] Total Capital Cost includes the cost for two compressors, two tanks, an air dryer and installation. Installation costs are assumed to be equal to 1.5 times the cost of capital. Equipment costs were derived from the 2012 NSPS TSD.
[b] These costs have been converted to 2012 dollars (from 2008 dollars) using the Federal Reserve Economic Data GDP Price Deflater (Change in GDP: Implicit Price Deflator from 2008 to 2012 (5.69 percent).[89]
[c] The annualized cost was estimated using a 7 percent interest rate and 10-year equipment life. Annual cost includes the cost of electrical power, as listed in Table 6-5, and labor.

[89] U.S. Bureau of Economic Analysis. *Gross Domestic Product: Implicit Price Deflator (GDPDEF]*, retrieved from FRED, Federal Reserve Bank of St. Louis. https://research.stlouisfed.org/fred2/series/GDPDEF/ March, 26, 2015.

For new natural gas processing plants, the cost-effectiveness of the three representative instrument air system sizes was evaluated in the 2015 NSPS Proposal TSD 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 for multiple control loops and size the instrument air system accordingly. Table 6-7 summarizes the natural gas processing segment cost of control per ton of VOC reduced for three sizes of representative instrument air systems. For existing natural gas processing plants, it is our understanding that these plants have already upgraded to instrument air unless the function has a specific need for a high-bleed pneumatic controller, which would most likely be safety related. The cost of converting the pneumatic controllers to instrument air includes the capital cost of $2,000 for the ductwork and annual cost of $285 (assuming a 10-year equipment life at 7 percent interest). The VOC cost of control for converting pneumatic controllers to instrument air for processing plants that already have instrument air ranges from $6 to $68 per ton of VOC removed, depending on the size of the instrument air system.

For natural gas processing, the cost of control of the three representative instrument air systems was evaluated based on the emissions mitigated from the number of control loops the system can provide and not on a per controller basis. This approach was chosen because we assume new processing plants will need to provide instrumentation for multiple control loops and size the instrument air system accordingly. We also assume that existing processing plants have already upgraded to instrument air unless the function has a specific need for a high-bleed pneumatic controller, which would most likely be safety related. Table 6-7 summarizes the natural gas processing segment cost of control per ton of VOC reduced for three sizes of representative instrument air systems.

Table 6-7. Cost of Control of Representative Instrument Air Systems in the Natural Gas Processing Segment ($2012)

System Size	Number of Control Loops	VOC Annual Emission Reduction (tpy)[a]	Value of Product Recovered ($2012/year)[b]	Annualized Cost of System		VOC Cost of Control ($2012/ton)	
				Without Savings	With Savings	Without Savings	With Savings
Small	15	4.18	$3,485	$11,722	$8,236	$2,804	$1,970
Medium	63	17.5	$14,592	$38,977	$24,385	$2,227	$1,393
Large	175	48.7	$40,606	$85,097	$44,490	$1,747	$914

[a] Based on the emissions mitigated from the entire system, which includes multiple control loops.
[b] Value of recovered product assumes natural gas processing is 82.9 percent methane by volume. A natural gas price of $4 per Mcf was assumed.

6.3.1.3 Electrically Powered Systems in Place of Bleed Devices

Description

Mechanical controls have been widely used in the oil and natural gas industry. They operate using a combination of levers, hand wheels, springs and flow channels with the most common mechanical control device being a liquid-level float to the drain valve position with mechanical linkages.[90] Another device that is increasing in use is electrically powered controls. Small electrical motors (including solar powered) have been used to operate valves and have no VOC emissions. Solar-powered control systems are driven by solar-power cells that actuate mechanical devices using electric power. As such, solar cells require some type of backup power or storage to ensure reliability.

Control Effectiveness[91]

Application of mechanical controls is limited because the control must be located in close proximity to the process measurement. Mechanical systems may have difficulty handling larger flow fluctuations. Electrically powered valves are only reliable with a constant supply of electricity. These controllers can achieve a 100 percent reduction in VOC emissions where applicable.

Cost Impacts

Depending on supply of power, mechanical and solar-power system costs can range from below $1,000 to $10,000 for an entire system.[92]

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[90] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry.* Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

[91] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

[92] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry.* Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

6.3.1.4 Enhanced Maintenance of Natural Gas-Driven Pneumatic Controllers

Manufacturers of pneumatic controllers indicate that emissions in the field can be higher than the reported gas consumption due to operating conditions, age and wear of the device.[93] Examples of circumstances or factors that can contribute to this increase include:[94,95]

(1) Nozzle corrosion resulting in more flow through a larger opening;
(2) Broken or worn diaphragms, springs (e.g., spring broken that holds the supply pilot plug on its seat), bellows, fittings (e.g., leaking tubing/tubing-fittings) and nozzles;
(3) Corrosives in the gas leading to erosion and corrosion of control loop internals;
(4) Improper installation;
(5) Lack of maintenance (maintenance includes replacement of the filter used to remove debris from the supply gas and replacement of O-rings and/or seals);
(6) Lack of calibration of the controller or adjustment of the distance between the flapper and nozzle;
(7) Foreign material lodged in the pilot seat;
(8) Debris/deposits on vent pilot plug. Material on the vent pilot can allow the controller to exhaust gas during the activation cycle;
(9) Debris/deposits on the supply pilot plug. Material on the supply pilot can cause the introduction of gas while the vent is open; or
(10) Wear in the seal seat.

The EPA prepared a white paper titled "Oil and Natural Gas Sector Pneumatic Devices," in 2014, requesting specific comment on available emissions data for pneumatic devices. One of the comments received regarding data presented in "Measurements of Methane Emissions at Natural Gas Production Sites in the United States"[96] was that the data set reported was dominated by extreme values. The commenter noted that the highest emitting controllers are simply controllers emitting at a large rate, regardless of their service or design type. These

[93] Ibid.
[94] Ibid.
[95] American Petroleum Institute (API). *Pneumatic Controllers*. Webinar Prepared and Presented to the U.S. Environmental Protection Agency. March 25, 2014.
[96] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Pneumatic Devices*. *Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel* Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415pneumatic.pdf.

controllers can have high emissions because of factors, other than design, related to maintenance, malfunction, or defect.[97]

Maintenance of pneumatics can correct many of these problems and can be an effective method for reducing emissions. Cleaning and tuning, in addition to repairing leaking gaskets, tubing fittings, and seals, can save 5 to 10 scfh per device. Eliminating unnecessary valve positioners can save up to 18 scfh per device.[98]

6.3.2 Existing Federal, State and Local Regulations

6.3.2.1 Federal Regulations that Specifically Require Control of VOC Emissions

Under the 2012 NSPS and 2016 NSPS, new or modified continuous bleed natural gas-driven pneumatic controllers at natural gas processing plants are subject to a VOC emission limit of zero (equivalent to non-natural gas-driven pneumatic controllers). Continuous bleed natural gas-driven pneumatic controllers in the production segment must have a bleed rate of 6 scfh or less.

6.3.2.2 State and Local Regulations that Specifically Require Control of VOC Emissions

States may have permitting restrictions on VOC emissions that apply to an emissions source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met and, often, how the source must be operated. To ensure that sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

For pneumatic controllers, Colorado and Wyoming have existing control requirements similar to those required under the 2012 NSPS and 2016 NSPS. Other states have permitting and

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[97] Allen, David. Comments Provided to the EPA on *Oil and Natural Gas Sector Pneumatic Devices-Peer Review Document*. University of Texas at Austin. June 2014.

[98] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

registration rules for controlling fugitive VOC emissions (which would include non-bleed emissions from pneumatic controllers).

Colorado requires that no- or low-bleed pneumatic controllers with a bleed rate of 6 scfh or less be installed for all new and existing applications (unless approved for use due to safety and/or process purposes) statewide (Regulation 7, XVIII.C.2). Where technically and economically feasible, Colorado requires no-bleed pneumatic controllers at facilities that are connected to the electric grid and using electricity to power equipment.

Wyoming requires the installation of low- or no-bleed pneumatic controllers with a bleed rate of 6 scfh or less at all new facilities. Upon modification of facilities, new pneumatic controllers must be low- or no-bleed and existing controllers must be replaced with no- or low-bleed controllers (at well site facilities only and not at natural gas processing plants).

Although some local rule requirements do not specifically require the control of VOC emissions from pneumatic controllers, local permit requirements (such as those required by the Bay Area Air Quality Management District) may require that a permit to operate applicant provide the number of high-bleed and low-bleed pneumatic devices in a permit application. Under some situations where facilities use high-bleed devices, the permitting authority might require an owner or operator to provide device-specific bleed rates and supporting documentation for each high-bleed device. In cases where high-bleed devices must be used, the permitting authority may require that the facility conduct fugitive monitoring and/or implement control requirements under conditions of their permit to operate.[99]

6.4 Recommended RACT Level of Control

Sections 6.4.1 and 6.4.2 present the recommended RACT level of control for continuous bleed natural gas-driven pneumatic controllers located at natural gas processing plants and continuous bleed natural gas-driven pneumatic controllers located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline.

[99] Cheng, Jimmy. *Permit Handbook. Chapter 3.5 Natural Gas Facilities and Crude Oil Facilities.* Bay Area Air Quality Management District. September 16, 2013.

6.4.1 Continuous Bleed Natural Gas-Driven Pneumatic Controllers Located at a Natural Gas Processing Plant

Based on our evaluation of available data obtained in the development of the 2012 NSPS and 2016 NSPS, peer review comments received on the "Oil and Natural Gas Sector Pneumatic Devices" white paper, and existing regulations that control VOC emissions from pneumatic controllers, we recommend that VOC emissions from an individual continuous bleed natural gas-driven pneumatic controller located at a natural gas processing plant be controlled by RACT. As noted in section 6.3.2, both Colorado and Wyoming require either low- or no-bleed controllers (where a high-bleed controller is defined as emitting at least 6 scfh); and the 2012 NSPS and 2016 NSPS require that new and modified individual continuous bleed pneumatic controllers at natural gas processing plants have a natural gas bleed rate of 0 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 0 scfh). For existing individual continuous bleed pneumatic controllers at natural gas processing plants, our RACT recommendation is that controllers have a natural gas bleed rate of 0 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 0 scfh). Our rationale for selecting a natural gas bleed rate of 0 scfh (with functional and safety exceptions) for our recommended RACT is based on the ability of most natural gas processing plants to install and utilize an instrument air system. As discussed in section 6.3.1.2 of this chapter, by using an instrument air system, compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic controller. Therefore, the use of instrument air eliminates natural gas and VOC emissions from pneumatic controllers and supports a natural gas bleed rate of 0 scfh.

In order to meet an emission limit of 0 scfh, natural gas processing plants would likely need to use an instrument air system. The use of instrument air eliminates natural gas and VOC emissions from natural gas-driven pneumatic controllers. We believe that most natural gas processing plants already meet the recommended RACT level of control by driving controllers with instrument air or other non-gas-driven controls unless there is a specific need for a high-bleed pneumatic controller. Nonetheless, for those natural gas processing plants that do not have an installed instrument air system, the cost of control of installing three representative instrument air systems was evaluated under the 2012 NSPS and 2016 NSPS based on the emissions mitigated from the number of control loops the system can provide (see section 6.3.1.2 of this chapter). Based on this analysis, the cost of this option was considered to be reasonable for natural gas processing plants (see Table 6-7 of section 6.3.1.2 of this chapter). The cost of control per ton of VOC reduced was estimated at $1,700 - $2,800 without savings and $910 - $2,000 with savings. For determining potential cost impacts, a major assumption made was that processing plants are constructed at locations with sufficient electrical service to power the instrument air compression systems.

In summary, we recommend the following RACT for each continuous bleed natural gas-driven pneumatic controller located at a natural gas processing plant:

> RACT for Each Continuous Bleed Natural Gas-Driven Pneumatic Controller Located at a Natural Gas Processing Plant:[100] Each continuous bleed natural gas driven pneumatic controller located at a natural gas processing plant must have a natural gas bleed rate of 0 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 0 scfh).

6.4.2 Continuous Bleed Natural Gas-Driven Pneumatic Controllers Located from the Wellhead to the Natural Gas Processing Plant or Point of Custody Transfer to an Oil Pipeline

Based on our evaluation of available data obtained in the development of the 2012 NSPS and 2016 NSPS, peer review comments received on the “Oil and Natural Gas Sector Pneumatic Devices” white paper, and existing regulations that control VOC emissions from pneumatic controllers, we are recommending a natural gas bleed rate less than or equal to 6 scfh with limited exceptions described below as the RACT for controlling VOC emissions from continuous bleed natural gas-driven pneumatic controllers located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline. We are also recommending that no requirements apply under RACT for pneumatic controllers that have a natural gas bleed rate less than or equal to 6 scfh that are located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline.

[100] In the NSPS, we excluded from the NSPS affected facility status non-natural gas-driven pneumatic controllers located at natural gas processing plants. Natural gas-driven controllers exempt from the zero VOC emission standard under the functional needs exclusion would still be affected facilities and would have certain tagging, recordkeeping and reporting requirements.

As indicated in section 6.2.2 of this chapter, low-bleed pneumatic controllers can emit up to 6 scfh. Both Colorado and Wyoming conditionally require either low- or no-bleed controllers (where a high-bleed controller is defined as emitting greater than 6 scfh); and the 2012 NSPS and 2016 NSPS require that new and modified individual continuous bleed pneumatic controllers have a bleed rate of 6 scfh or less (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 6 scfh). For purposes of this CTG, and consistent with the definition of high-bleed controller used for the 2012 NSPS, 2016 NSPS, and both the Wyoming and Colorado state regulations, a high-bleed pneumatic device is defined as emitting greater than 6 scfh to the atmosphere.

Although both Wyoming and Colorado specifically require low-bleed or no-bleed pneumatic controllers in place of high-bleed controllers (where technically and economically feasible), we are recommending a RACT emission limit of 6 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 6 scfh) apply to each continuous bleed pneumatic controller. This approach allows flexibility in how a source chooses to limit VOC emissions from an applicable individual pneumatic controller and acknowledges that there may be circumstances where it is not practical to meet a 6 scfh limit. By requiring a limit be met, facilities have the option of controlling emissions by one or more options presented in section 6.3.1 of this chapter (e.g., replace a high-bleed device with a low-bleed device and implement enhanced monitoring to mitigate increased VOC emissions from poor maintenance/poor operation) depending on site-specific circumstances. We are including this flexibility in our recommended RACT to address the varied control options and applicability issues (e.g., instrument air systems require access to electrical power or a backup pneumatic controller and access to electric power or backup pneumatic controllers may not be available in remote locations) presented in section 6.3.1 of this chapter.

Although facilities would have flexibility in how they meet the recommended RACT level of control, by establishing an emission limit equal to the design bleed rate for a low-bleed device (6 scfh), we believe that most facilities would likely replace high-bleed controllers with low-bleed controllers (it is assumed about 80 percent of high-bleed devices can be replaced with low-bleed devices).[101] For the production segment, we estimated that, on average, 1.41 tons of VOC would be reduced annually per device in the production segment from installing a low-bleed device in place of a high-bleed device.

As presented in section 6.3.1.1 of this chapter, the cost of replacing a high-bleed device with a new low-bleed device is on the order of $2,698 per device, and the cost of control in the production segment is estimated to be $210 per ton of VOC emissions reduced without savings. Considering the cost savings of gas recovered from installing a low-bleed device in place of a high-bleed device, it is estimated that there would be an overall net savings.

In summary, we recommend the following RACT for each single continuous bleed natural gas-driven pneumatic controller located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline:

> RACT for Each Single Continuous Bleed Natural Gas-Driven Pneumatic Controller Located from the Wellhead to the Natural Gas Processing Plant or Point of Custody Transfer to an Oil Pipeline: Each pneumatic controller, which is a single continuous bleed natural gas-driven pneumatic controller[102] must have a natural gas bleed rate less than or equal to 6 scfh (unless there are functional needs including, but not limited to response time, safety and positive actuation, requiring a bleed rate greater than 6 scfh).

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[101] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

[102] In the NSPS, we excluded from NSPS pneumatic controller affected facility status continuous bleed natural gas-driven pneumatic controllers with a bleed rate not greater than 6 scfh (low-bleed controllers) located in the production segment. Continuous bleed natural gas-driven controllers exempt from the 6 scfh bleed rate emission standard under the functional needs exclusion would still be affected facilities and would have certain tagging, recordkeeping and reporting requirements.

6.5 Factors to Consider in Developing Pneumatic Controller Compliance Procedures

6.5.1 Oil and Natural Gas Production (Individual Continuous Bleed Pneumatic Controller with a Natural Gas Bleed Rate Greater than 6 scfh Located from the Wellhead to the Natural Gas Processing Plant or Point of Custody Transfer to an Oil Pipeline)

To ensure that each continuous bleed natural gas-driven pneumatic controller located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline is operated with a natural gas bleed rate less than or equal to 6 scfh (the recommended RACT level of control), we recommend that regulating agencies specify operating, recordkeeping and reporting requirements to document compliance. It is recommended that air agencies require that each pneumatic controller be tagged with the month and year of installation and identification information that allows traceability to manufacturer's documentation.

It is recommended that air agencies require owners and operators of continuous bleed natural gas-driven pneumatic controllers that are subject to RACT maintain records that: (1) document the location and manufacturer's specifications of each pneumatic controller; (2) if applicable, provide a demonstration as to why the use of a pneumatic controller with a natural gas bleed rate greater than 6 scfh is required (the recommended RACT level of control); and (3) document deviations in cases where a pneumatic controller was not operated in compliance with RACT.

It is also recommended that air agencies require owners and operators to submit annual reports that include (1) if applicable, documentation that the use of a pneumatic controller with a natural gas bleed rate greater than 6 standard cubic feet per hour is required and the reasons why; and (2) the records of deviations that occurred during the reporting period.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

6.5.2 Natural Gas Processing Segment (Individual Continuous Bleed Natural Gas-Driven Pneumatic Controller Located at a Natural Gas Processing Plant)

To ensure each continuous bleed natural gas-driven pneumatic controller at natural gas processing plants is operated with a natural gas bleed rate of zero (the recommended RACT level of control), we suggest that air agencies specify operating, recordkeeping and reporting requirements to document compliance. We also suggest that air agencies require that each pneumatic controller be tagged with the month and year of installation and identification information that allows traceability to the manufacturer's documentation. It is recommended that air agencies require owners and operators of pneumatic controllers maintain records that: (1) document the location and manufacturer's specifications of each pneumatic controller; (2) document that the natural gas bleed rate is zero; and (3) document deviations in cases where a pneumatic controller was not operated in compliance with RACT.

It is also recommended that air agencies require owners and operators to submit annual reports that include the records of deviations that occurred during the reporting period.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

7.0 PNEUMATIC PUMPS

The oil and natural gas industry uses a variety of pneumatic gas-driven pumps where there is no reliable electrical power to "control processing problems and protect equipment."[103] Pneumatic pumps are "small positive displacement, reciprocating units used throughout the oil and natural gas industry to inject precise amounts of chemicals into process streams or for freeze protection glycol circulation."[104] Most chemical injection pumps fall into two main types: (1) diaphragm pumps, generally used for heat tracing; or (2) plunger/piston, generally used for chemical and methanol injection. Pneumatic pumps driven by natural gas emit natural gas, which contains VOC. Other types of pneumatic pumps may be driven by gases other than natural gas and, therefore, do not emit VOC. The focus of this CTG is natural gas-driven pneumatic pumps. This chapter provides a description of pneumatic pumps that are used in the oil and natural gas industry, including their function and associated emissions. This chapter also provides control techniques used to reduce VOC emissions from pneumatic pumps, along with costs and emission reductions. Finally, this chapter provides a discussion of our recommended RACT for pneumatic pumps and the associated VOC emission reductions and costs.

7.1 Applicability

For the purposes of this CTG, a pneumatic pump is a positive displacement reciprocating unit used for injecting precise amounts of chemicals into a process stream or for glycol circulation. The pneumatic pump may use natural gas or another gas to drive the pump. The emissions and emission control options discussed herein would apply to natural gas-driven chemical/methanol and diaphragm pumps located at natural gas processing plants and well sites.

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[103] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 13: Chemical Injection Pumps*. EPA-600/R-96-080b. June 1996.

[104] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

7.2 Process Description and Emission Sources

7.2.1 Process Description

As noted above, pneumatic pumps are "positive displacement, reciprocating units used for injecting precise amounts of chemicals into a process stream or for glycol circulation."[105] Pneumatic pumps often make use of gas pressure where electricity is not readily available.[106] In the production segment, the supply gas is mostly produced natural gas, whereas in the processing segment, the supply gas may be compressed air. For natural gas-driven pneumatic pumps, characteristics that affect VOC emissions include the frequency of operation, the size of the unit, the supply gas pressure, and the inlet natural gas composition.[107]

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 may 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.[108] 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. Chemical injection pumps (i.e., piston/plunger pumps or small diaphragm pumps) inject small 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.

Pneumatic pumps have two major components, a driver side and a motive side, which operate in the same manner but with different reciprocating mechanisms. Pressurized gas provides energy to the driver side of the pump, which operates a piston or flexible diaphragm to draw fluid into the pump. The motive side of the pump delivers the energy to the fluid being moved in order to discharge the fluid from the pump. The natural gas leaving the exhaust port of

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[105] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.
[106] Ibid.
[107] Ibid.
[108] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Pneumatic Devices*. *Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel.* Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415pneumatic.pdf.

the pump is either directly discharged into the atmosphere or is recovered and used as a fuel gas or stripping gas.[109]

Chemical injection pumps are positive displacement, reciprocating units designed to inject precise amounts of chemical into a process stream. Positive displacement 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.[110]

Typical chemicals injected in an oil or natural 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. Because the injection rates are typically small, the pumps are also small. They are often attached to barrels containing the chemical being injected.[111]

Diaphragm pumps are positive displacement pumps, meaning they use contracting and expanding cavities to move fluids. 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.[112]

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[109] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.
[110] Ibid.
[111] Ibid.
[112] GlobalSpec. *Diaphragm Pumps Information*. Available online - http://www.globalspec.com/learnmore/flow_transfer_control/pumps/diaphragm_pumps.

Not all pneumatic pumps are natural gas driven. At sites without electrical service sufficient or reliable enough to power an instrument air compressor control system, mechanical or electrically powered pneumatic pumps may be used. Where reliable electrical service is available, sources of power other than pressurized natural gas, such as compressed instrument air may be used. Because these devices are not natural gas driven, they do not directly release natural gas or VOC emissions. Instrument air systems are feasible only at oil and natural gas industry locations where the devices can be driven by compressed instrument air systems and have electrical service sufficient and reliable enough to power a compressor. This analysis assumes that natural gas processing plants are likely to have electrical service sufficient to power an instrument air system, and that most existing gas processing plants use instrument air instead of natural gas-driven pumps.[113] The application of electrical controls is discussed further in section 7.3 of this chapter.

7.2.2 Emissions Data

7.2.2.1 Summary of Major Studies and Emissions

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 reference. In addition to these sources, we evaluated the peer reviewer and public comments received on the EPA's white paper, "Oil and Natural Gas Sector Pneumatic Devices."[114]

[113] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices*. EPA-600/R-96-080k. June 1996.

[114] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Pneumatic Devices*. *Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel*. Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415pneumatic.pdf.

Table 7-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[g]
Greenhouse Gas Reporting Program[a]	EPA	2014	Nationwide	X	
Inventory of Greenhouse Gas Emissions and Sinks[b]	EPA	Annual	Nationwide/ Regional	X	
Methane Emissions from the Natural Gas Industry[c,d]	EPA/GRI	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry[e]	EPA	1999	Nationwide	X	
Natural Gas STAR Program[f]	EPA	2012	Study Specific	X	X

[a] U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2014.
[b] U.S Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html.
[c] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 2: Technical Report.* EPA-600/R-96-080b. June 1996; U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 3: General Methodology*. EPA-600/R-96-080c. June 1996.
[d] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 5: Activity Factors*. EPA-600/R-96-080e. June 1996; and U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices*. EPA-600/R-96-080k. June 1996.
[e] U.S. Environmental Protection Agency. *Methane Emissions from the U.S. Petroleum Industry. Final Report*. Prepared for the U.S. Environmental Protection Agency by Radian International LLC. EPA-600/R-99-010. February 1999.
[f] U.S. Environmental Protection Agency. *Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR. Washington, DC. October 2006.
[g] An "X" in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

7.2.2.2 Representative Pneumatic Pump Emissions

For this analysis, we consulted information in the appendices of Natural Gas STAR lessons learned documents on pneumatic pumps,[115,116] the GHGRP, the GHG Inventory, and

[115] U.S. Environmental Protection Agency. Lessons Learned: *Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas STAR. Washington, DC. October 2006.
[116] 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.

U.S. EPA/GRI Report.[117] The GHGRP and GHG Inventory use emission factors from the U.S. EPA/GRI Report. Similarly, we determined that the best available emission factors for pneumatic pumps are presented in the U.S. EPA/GRI Report.

The basic approach used for this analysis was to first approximate methane emissions from the average pneumatic pump in the production and processing segments and then estimate VOC and HAP emissions using the gas composition factors from the 2011 Gas Composition Memorandum. The specific gas composition ratio used for this analysis was 0.278 lbs VOC per pound methane in the production and processing segment. Table 7-2 summarizes the estimated average emission factors for a representative pneumatic pump for the production and processing segments for both methane and VOC.

Table 7-2. Average Emission Estimates per Pneumatic Device

Segment/Pump Type	Emission Factor Methane (scf/day) [a]	Emission Factor Methane (Mcf/yr)[b]	Emission Factor Methane (tpy)[c]	Emission Factor VOC (tpy)[d]
Production				
Diaphragm	446	163	3.46	0.96
Piston	48.9	18	0.38	0.11
Processing				
Small Diaphragm	446	163	3.46	0.96
Medium Diaphragm	446	163	3.46	0.96
Large Diaphragm	446	163	3.46	0.96
Small Piston	48.9	18	0.38	0.11
Medium Piston	48.9	18	0.38	0.11
Large Piston	48.9	18	0.38	0.11

[a] Data Source: EPA/GRI. *Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps*. June 1996 (EPA-600/R -96-080m), Sections 5.1 – Diaphragm Pumps and 5.2 – Piston Pumps.
[b] Assumes 365 days/yr operation in natural gas production and processing.
[c] Assumes density of methane is 19.26 g/scf.
[d] Assumes 0.278 VOC content per pound of methane.

[117] 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).

7.3 Available Controls and Regulatory Approaches

7.3.1 Available VOC Emission Control Options

Natural gas-driven pneumatic pumps emit VOC emissions as part of their normal operation. Depending on the type of pump and the constraints of the location, companies can utilize a variety of technologies that have been developed over the years. In situations where the replacement of natural gas-driven pumps with electric, solar and instrument air pumps is not feasible, emissions can be captured and routed to a VRU or to a combustion device.

Sections 7.3.1.1 and 7.3.1.2 discuss the control of VOC emissions by replacing natural gas-driven pumps with solar pumps and electric pumps. Section 7.3.1.3 discusses the use of an instrument air system to drive the pneumatic pump in order to eliminate VOC emissions. Lastly, section 7.3.1.4 discusses reducing VOC emissions by routing emissions from the pump to a combustion device, and section 7.3.1.5 discusses capturing VOC emissions using a VRU.

7.3.1.1 Solar Pumps

Description

Solar pumps provide the same functionality as natural gas-driven pumps and can be utilized at remote sites where electricity is not available. However, peer review comments received on the EPA's white paper "Oil and Natural Gas Sector Pneumatic Devices" noted that they predominantly operated solar-powered pneumatic pumps for chemical injection and the pumps failed as early as after two to three cloudy days due to insufficient battery charge.[118] When solar pumps are properly charged, a solar-charged DC pump can handle a range of throughputs up to 100 gallons per day with maximum injection pressure around 3,000 psig and have no VOC emissions. Converting natural gas-driven chemical pumps can reduce methane emissions by an estimated 3.46 tpy per diaphragm pump and 0.38 tpy per piston pump for all segments of the oil and natural gas industry.[119] Based on the gas composition for natural gas in the production segment, we estimate that replacement of a pneumatic pump with a solar-powered pump will reduce VOC emissions by 0.96 tpy per diaphragm pump and 0.11 tpy for a piston pump.

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[118] Reese, Carrie, Environmental Compliance Manager. Comments on the Oil and Natural Gas Sector Pneumatic Devices. Pioneer Natural Resources.

[119] U.S. Environmental Protection Agency. PRO Fact Sheet No. 202. *Convert Natural Gas-Driven Chemical Pumps*.

Control Effectiveness

Replacing a natural gas-driven pump with a solar pump can result in 100 percent reduction in VOC emissions and is feasible in regions where there is sufficient sunlight to power the pump, and backup power is not required. Although, as stated above, solar-powered pumps are capable of pumping up to 100 gallons per day, they are typically used for low volume applications to inject methanol or corrosion inhibitors into a well with typical volumes ranging from 6 to 8 gallons per day. In addition to the low volume pumps, large volume pumps used to replace natural gas-assisted circulation pumps for glycol dehydrators can also be converted to solar.

Cost Impacts

The primary costs associated with conversion to solar pumps are the initial capital expenditures. Solar pumps generally have low maintenance costs, which are typically lower than natural gas-driven pump maintenance costs. The cost being attributed to the replacement of pneumatic pumps with solar-powered pumps includes the capital cost of the pump and its associated operating costs. The operating costs are estimated to be 10 percent of the capital cost. Based on the Natural Gas STAR document, "PRO Fact Sheet: Convert Natural Gas-Driven Chemical Pumps,"[120] the capital (purchase) cost for a solar-powered electric pump is 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 is $2,227 (2012 dollars). We estimate there would be no additional annual operating costs for solar pumps above and beyond that of ordinary field personnel duties. Annualized over the life of the pump at a 7 percent discount rate, the annualized cost of replacing a pneumatic pump with a solar pump is $317. In addition, the use of solar pumps will have savings realized from the natural 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 per diaphragm pump and $87 per year per piston pump.

[120] U.S. Environmental Protection Agency. PRO Fact Sheet No. 202. *Convert Natural Gas-Driven Chemical Pumps*.

7.3.1.2 Electric Pumps

Description

Electric pumps provide the same functionality as natural gas-driven pumps, and are only restricted by the use of reliable power. Electric pumps have no VOC emissions, and converting a natural gas-driven pneumatic pump to an electric pump can reduce VOC emissions by an estimated 0.96 tpy per diaphragm pump and 0.11 tpy per piston pump.

Control Effectiveness

Replacing a natural gas-driven pump with an electric pump can result in 100 percent reduction in VOC emissions. However, use of electric pumps requires a sufficient and reliable source of electricity. These pumps are, therefore, more common at natural gas processing plants or large dehydration facilities that have access to reliable electric power.

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,"[121] the cost of an electric pump to replace a diaphragm pump is $4,647 and to replace a piston pump is $1,819 in 2012 dollars depending on the horsepower of the unit.[122] The annual operating costs for an electric pump are estimated to be $293. Based on these costs annualized over the life expectancy of the pump at a 7 percent discount rate, the annualized cost for an electric pump to replace a diaphragm pump is $954, and $552 to replace a piston pump. In addition, the use of electric pumps will have savings realized from the natural 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 per diaphragm pump and $87 per year per piston pump.

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[121] Ibid.

[122] U.S. Environmental Protection Agency. *Lessons Learned*. *Replacing Gas-Assisted Glycol Pumps with Electric Pumps*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. 2006. October 2006.

7.3.1.3 Instrument Air System

Description

Instrument air systems require a compressor, power source, dehydrator, and volume tank. The same pneumatic pumps can be used for natural gas and compressed air, without altering any of the parts of the pneumatic pump, but instrument air eliminates the emissions of natural gas. All facilities that have access to an adequate and reliable source of electricity can install an instrument air system. The following, taken from the Natural Gas STAR document, "PRO Fact Sheet: Convert Gas Pneumatic Controls to Instrument Air,"[123] describes the major components of an instrument air system:

(1) 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 emission rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank. For reliability, a full spare compressor is normally installed.

(2) 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, natural gas-driven 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 ensure. In some instances, solar-powered, battery-operated air compressors can be feasible for remote locations, which would both reduce VOC emissions and energy consumption. Small natural gas-powered fuel cells are also being developed.

[123] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

(3) 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.

(4) 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, such as for a motor starter, pneumatic pump, or pneumatic tools, without affecting the process control functions.

Control Effectiveness

Instrument air eliminates all emissions from natural gas-driven pneumatic 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.[124] Because all emissions can be avoided by converting natural gas-driven chemical pumps to instrument air, methane emissions can be reduced by an estimated 3.46 tpy per diaphragm pump and 0.38 tpy per piston pump. Based on the gas composition for natural gas in the production segment, we estimate that converting a natural gas-driven pneumatic pump to instrument air will reduce VOC emissions by 0.96 tpy per diaphragm pump and 0.11 tpy per piston pump.

Cost Impacts

As stated previously, 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 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.[125]

The costs associated with instrument air systems are primarily capital costs for the compressor(s), air dryer and the volume tank, but also include operational costs for electricity to

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[124] Ibid.

[125] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

drive the compressor motor. Other components of the instrument air system, including piping, control instruments and valve actuators, would already be in place for a gas system. We assume that existing processing plants have an instrument air system in place, including backup systems, and that the cost of increasing air load on the system would be confined to the incremental cost associated with upgrading or replacing the compressor and connecting the pumps to the system. The size of the compressor required would depend on the additional air load required for the instrument air system to handle the pneumatic pumps. Table 7-3 summarizes cost estimates to replace various size compressors in an existing instrument air system.

Table 7-3. Cost of Compressor Replacement for Existing Instrument Air System ($2012)

Compressor Size	Total Capital Cost[a]	Annualized Cost[b]	Total O&M Cost[c]	Annual Cost[d]
Small	$5,999	$854	$9,197	$10,051
Medium	$29,989	$4,270	$28,002	$32,271
Large	$52,779	$7,515	$64,880	$72,394

[a] 2016 NSPS TSD.
[b] Annualized capital cost using a 7 percent interest rate and an equipment life of 10 years.
[c] The total O&M includes both the annual labor cost and the annual power cost.
[d] The total annual cost includes the annualized capital cost and the total O&M cost.

7.3.1.4 Route Emissions to an Existing or New Combustion Device

Description

Typical combustion devices used in the oil and natural gas industry to control VOC emissions and their control efficiency are discussed in greater detail in section 4.3.1.2 of chapter 4 of this document. It is assumed that most processing plants and large dehydration facilities have at least one existing combustion device onsite.

Control Effectiveness

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 discharged from the pump, but rather combusts the gas. Based on the gas composition for natural gas in the production segment, we estimated that routing emissions to a combustion device would reduce VOC emissions by an estimated 0.91 tpy per diaphragm pump and 0.1 tpy per piston pump.

Cost Impacts

Routing natural gas to an existing combustion device or installing a new combustion device have associated capital and operating costs. Based on costs for a combustion device provided in the 2015 NSPS TSD, the capital cost for installing a new combustion device to control emissions is estimated to cost $34,250 and the annual operating cost is $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 be approximately $21,877, using a 7 percent discount rate. The capital cost for routing emissions to an existing control device to control emissions is estimated to be $5,433 with an annualized cost of $774, using a 7 percent discount rate. Because the natural gas captured is combusted there is no gas savings associated with the use of a combustion device to reduce VOC emissions. Table 7-4 presents the estimated VOC cost of control for routing natural gas-driven pump emissions to an existing combustion device. Table 7-5 presents the cost of control for routing natural gas-driven pump emissions to a new combustion device.

Table 7-4. VOC Cost of Control for Routing Natural Gas-Driven Pump Emissions to an Existing Combustion Device

Pump Type/ Segment	VOC Emission Reductions (tpy/pump)	Annualized Cost ($2012)	VOC Cost of Control ($2012/ton)
Diaphragm Pumps			
Production	0.91	$774	$847
Processing	0.91	$774	$847
Piston Pumps			
Production	0.10	$774	$7,709
Processing	0.10	$774	$7,709

Table 7-5. VOC Cost of Control for Routing Natural Gas-Driven Pump Emissions to a New Combustion Device

Pump Type/ Segment	VOC Emission Reductions (tpy/pump)	Annualized Cost ($2012)	VOC Cost of Control ($2012/ton)
Diaphragm Pumps			
Production	0.91	$21,877	$23,944
Processing	0.91	$21,877	$23,944
Piston Pumps			
Production	0.10	$21,877	$218,017
Processing	0.10	$21,877	$218,017

7.3.1.5 Route Emissions to a Vapor Recovery Unit (VRU)

Description

Vapor recovery units capture low-pressure vapor streams, increase the pressure by means of a compressor, and then route the vapor stream to a process or other useful purpose. These systems typically include a backup compressor system to allow for shutdowns and repairs. Vapor recovery units are more economical for facilities with multiple natural 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. Vapor recovery units are discussed in greater detail in section 4.3.1.1 of chapter 4 of this document.

Control Effectiveness

Use of a vapor recovery technology has the potential to reduce the VOC emissions from natural gas-driven pumps by 100 percent if all vapor is recovered. We recognize that VRUs may not continuously meet this efficiency in practice. Therefore, we estimate that routing emissions from a natural gas-driven pump to an existing or newly installed VRU can reduce the VOC emitted by approximately 95 percent (accounting for any reduced efficiency that may occur) while, at the same time, capturing the natural gas for beneficial use. We estimate that methane emission reductions for routing gas to a VRU to be 3.29 tpy for a diaphragm pump and 0.36 tpy for a piston pump. Based on the gas composition for natural gas in the production segment, we estimate that routing emissions to a VRU can reduce VOC emissions by 0.91 tpy per diaphragm pump and 0.1 tpy per piston pump.

Cost Impacts

Based on costs for a VRU provided in the 2015 NSPS TSD, we estimate the capital cost of installing a VRU to be $104,111 and the annual operation and maintenance cost to be $9,932 in 2012 dollars. The total annualized cost of a new VRU is estimated to be $24,755 based on a 7 percent discount rate.

If a VRU is already onsite, then the additional costs for routing emissions from a pump are small, as the majority of costs are piping. We estimated the cost of routing emissions to an existing VRU to be $5,433 in 2012 dollars. The annualized cost of routing natural gas emissions to an existing VRU is estimated to be $774 based on a 7 percent discount rate. In addition, there is potential for beneficial use of natural gas recovered through the VRU. We estimated the annual natural gas recovered to be 187 Mcf per year per diaphragm pump and 21 Mcf per year per piston pump. The resulting natural gas savings is estimated to be $749 per diaphragm pump and $84 per piston pump, per year based on a value of $4.00 per Mcf of natural gas recovered. Table 7-6 presents the estimated VOC cost of control for routing natural gas-driven pump emissions to an existing VRU. Table 7-7 presents the estimated VOC cost of control for routing gas-driven pump emissions to a new VRU.

Table 7-6. VOC Cost of Control for Routing Natural Gas-Driven Pump Emissions to an Existing VRU

Pump Type/ Segment	VOC Emission Reductions (tpy/pump)	Annualized Cost ($2012)	VOC Cost of Control ($2012/ton)	
			Without savings	With savings
Diaphragm Pumps				
Production	0.91	$774	$847	$27
Processing	0.91	$774	$847	$27
Piston Pumps				
Production	0.10	$774	$7,709	$6,876
Processing	0.10	$774	$7,709	$6,876

Table 7-7. VOC Cost of Control for Routing Natural Gas-Driven Pump Emissions to a New VRU

Pump Type/ Segment	VOC Emission Reductions (tpy/pump)	Annualized Cost ($2012)	VOC Cost of Control ($2012/ton)	
			Without savings	With savings
Diaphragm Pumps				
Production	0.91	$24,755	$27,094	$26,275
Processing	0.91	$24,755	$27,094	$26,275
Piston Pumps				
Production	0.10	$24,755	$246,697	$245,864
Processing	0.10	$24,755	$246,697	$245,864

7.3.2 Existing Federal, State and Local Regulations

7.3.2.1 Federal Regulations that Specifically Require Control of VOC Emissions

The EPA has finalized federal requirements for natural gas-driven pneumatic pumps under subpart OOOOa. Under subpart OOOOa, each natural gas-driven diaphragm pump located at a natural gas processing plant must have zero natural gas emissions, and each natural gas-driven diaphragm pump located at a well site must capture and route emissions to a control device or process if there is an existing control device or process available onsite. Subpart OOOOa requires that VOC and methane emissions be reduced by 95 percent or greater unless the existing control device or process is not capable of reducing emissions by 95 percent or greater, unless (1) there is no control device onsite, (2) it is technically infeasible, or (3) the control device cannot achieve 95 percent control. Subpart OOOOa also includes an exemption from control requirements where a diaphragm pump operates for any period of time each calendar day for less than a total of 90 days per calendar year.

7.3.2.2 State and Local Regulations that Specifically Require Control of VOC Emissions

States may have permitting restrictions on VOC emissions that may apply to an emission source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met and, often, how the source may be operated. To ensure that sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

At least one state (Wyoming) requires emissions associated with the discharge streams from all natural gas-operated pneumatic pumps be controlled by at least 98 percent or routed into a closed-loop system (e.g., sales line, collection line, fuel supply line). Several states also have registration rules for controlling fugitive VOC emissions (which may include fugitive emissions from pneumatic pumps).

7.4 Recommended RACT Level of Control

We evaluated available data obtained in the development of the 2016 NSPS final rule, comments received on the draft CTG and 2015 NSPS proposed rule, and peer review comments received on the EPA's white paper "Oil and Natural Gas Sector Pneumatic Devices." Based on our evaluation of these data and information, we recommend that VOC emissions from pneumatic pumps be controlled.

Our recommended RACT for an existing individual natural gas-driven diaphragm pump located at the well site is to capture and route VOC emissions to a control device or process where there is an existing control device or process available onsite. Our rationale for this recommendation is that, although the production segment includes both well sites and gathering and boosting stations, we currently only have reliable information for pumps located at well sites. We have determined that the cost of control for routing VOC emissions to an existing onsite control device or process would be reasonable. As presented in Tables 7-4 and 7-6 in sections 7.3.1.4 and 7.3.1.5 of this chapter, the VOC cost of control when an existing combustion device or VRU is available onsite was estimated to be $847 per ton of VOC reduced for diaphragm pumps, without gas savings, and $27 per ton of VOC reduced for diaphragm pumps if a VRU is used and gas savings are considered. We do not consider requiring control where there is not an existing control device or process onsite to be reasonably available technology, and the cost per ton of VOC reduced was estimated at greater than $20,000 for diaphragm pumps. While we are not recommending that the owner or operator be required to install a control device to control pneumatic pump emissions if one is not already available, we note that control devices will likely be installed onsite for other purposes under RACT or other regulations and will be available to control emissions from pneumatic pumps to a 95 percent control level.

For purposes of our recommended RACT, a natural gas-driven diaphragm pump is a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump for purposes of our recommended RACT. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

We do not recommend RACT apply to an existing individual natural gas-driven piston pump because currently available information (including information received on the draft CTG and 2015 NSPS proposal) indicates that piston pumps are low emitting because of their small size, design and usage patterns. We determined piston pumps have emission rates between 2.2 to 2.5 scf/hr based on a joint report from the EPA and the Gas Research Institute on methane emissions from the natural gas industry. This approach is consistent with the manner in which we addressed low-bleed pneumatic controllers. After considering the low emission rates of low-bleed pneumatic controllers, we do not recommend RACT apply to these sources. Similarly, based upon the information that we have on the low emission rates of piston pumps, we are not recommending RACT apply to these sources because VOC emissions are low and would not be reasonable to control in the same manner that we recommend for diaphragm pumps. As presented in Tables 7-4 and 7-6 in sections 7.3.1.4 and 7.3.1.5 of this chapter, the VOC cost of control when an existing combustion device or VRU is available onsite was estimated to be $7,709 per ton of VOC reduced for piston pumps, without gas savings, and $6,876 per ton of VOC reduced for piston pumps if a VRU is used and gas savings are considered. Requiring control where there is not an existing control device or process onsite was estimated to cost more than $200,000 per ton of VOC reduced for piston pumps.

For existing natural gas-driven diaphragm pumps at well sites, we recommend that air agencies require VOC emissions be controlled by 95 percent. Our rationale for recommending this level of emission reduction is supported by the control level achievable on a continuing basis by control devices and processes already located onsite or later installed onsite to control other emissions under RACT or other regulations. We expect that newly-installed control devices will achieve emission reductions because owners or operators are installing them to meet control requirements for other sources. In the unlikely circumstance where a control device that can achieve a 95 percent reduction is not available onsite, we recommend that owners and operators still be required to control VOC emissions to the level achievable by the control device. We recommend that owners and operators in those instances be required to maintain documentation of the percent control the onsite control device is designed to achieve. We make this additional recommendation because it will achieve emission reductions with regard to pneumatic pumps even in the unlikely circumstance that the only available control device cannot achieve a 95 percent reduction.

We also recommend that air agencies allow for an exemption based on technical infeasibility. We recommend a technical infeasibility exemption be allowed based on information we received from industry that indicates that there may be circumstances where there is insufficient gas pressure or control device capacity, making it technically infeasible to capture and route pneumatic pump emissions to a control device or process.

We recommend that, at well sites, if a diaphragm pump operates for any period of time each calendar day for less than a total of 90 days per calendar year, the pump not be subject to the recommended control requirements. We make this recommendation to account for those intermittently used pumps/portable pumps where VOC emissions would be lower than assumed in our analysis (i.e., our analysis assumes that diaphragm pumps are operated 40 percent of the time evenly throughout the year) and not reasonable to control.

Our recommended RACT for existing diaphragm pumps located at natural gas processing plants is that they have zero VOC emissions (or 100 percent control) (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring an emission rate greater than zero). Our rationale for selecting a VOC emission rate of zero (with functional and safety exceptions) for our recommended RACT is based on the ability of most natural gas processing plants to install and utilize an instrument air system. As discussed in section 7.3.1.3 of this chapter, by using an instrument air system, compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic system. Therefore, the use of instrument air eliminates VOC emissions from each gas-driven diaphragm pump and supports a VOC emission rate of zero.

In summary, we recommend the following RACT for pneumatic pumps in the oil and natural gas industry:

(1) Each Diaphragm Pump Located at a Natural Gas Processing Plant: Require zero VOC emissions (or 100 percent control). This can be achieved by use of an instrument air system in place of natural gas-driven pump.

(2) Each Diaphragm Pump Located at a Well Site: Require that VOC emissions be captured and routed to an existing control device or process that is located onsite, unless it is technically infeasible to route emissions to the existing control device or process. Require 95 percent control of VOC emissions, unless the existing control device or process cannot achieve 95 percent control. If the existing control device cannot achieve a 95 percent control, still require the emissions to be routed to the existing onsite control device to control emissions to the extent achievable and maintain documentation of the percent control the onsite control device is designed to achieve. If there is no existing control device at the location of the pump, submit a certification that there is no device. If a control device is subsequently added to the site where the pump is located, then the VOC emissions from the pump must be captured and routed to the newly installed control device.

Although sources have a choice on how they meet the RACT level of control, the technologies that will likely be used to meet the RACT level of control for each natural gas-driven diaphragm pump at a well site are either capturing and routing the VOC emissions to an onsite existing combustion device (or a subsequently installed combustion device) or capturing and routing the VOC emissions to a process using an onsite existing VRU (or a subsequently installed VRU).

Similarly, the technology that will likely be used to meet the RACT level of control for each diaphragm pump located at a natural gas processing plant is the use of an existing instrument air system assumed to already exist onsite at natural gas processing plants.

7.5 Factors to Consider in Developing Pneumatic Pump Compliance Procedures

7.5.1 Oil and Natural Gas Production Segment Recommendations

We recommend that air agencies require owners and operators of diaphragm pumps located at well sites that meet RACT by capturing emissions and routing to a control device be connected through a closed vent system and that the closed vent system be designed with no detectable emissions (using a 500 ppm detection level, as measured using Method 21 of appendix A-7 of part 60, and ongoing monthly, olfactory and auditory inspections). We recommend that you require that owners and operators conduct an assessment and certify that the closed vent system is of sufficient design and capacity to ensure that emissions are routed to the control device. We recommend air agencies require that any detected defects be repaired as soon as practicable.

With the exception of low leg drains, high point bleeds, analyzer vent, open-ended valves and safety devices, if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process, air agencies should require that owners or operators either:

(1) Install, calibrate, maintain and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings and either sounds an alarm or initiates notification via remote alarm to the nearest field office when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere; or
(2) Secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

Secondly, we recommend that air agencies require owners and operators of diaphragm pumps at well sites provide certifications for when (1) there is no existing control device or process onsite, or (2) capturing and routing to an existing control device or process is not technically feasible.

Lastly, we recommend that air agencies require owners and operators of diaphragm pumps at well sites maintain records documenting where (1) intermittently-used/portable diaphragm pumps operate for any period of time each calendar day for less than a total of 90 calendar days per year, (2) an onsite control device or process is designed to achieve less than 95 percent reduction, and (3) a diaphragm pump is routed to a control device or a process and the control device or process is subsequently removed.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

7.5.2 Natural Gas Processing Segment Recommendations

We recommend that air agencies require owners and operators of diaphragm pumps located at natural gas processing plants maintain records documenting (1) the location and manufacturer's specifications of each pneumatic pump, (2) that the natural gas bleed rate is zero, and (3) deviations in cases where a pneumatic pump was not operated in compliance with RACT. We also recommend that air agencies require owners and operators submit annual reports that include records of deviations that occurred during the reporting period.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

8.0 EQUIPMENT LEAKS FROM NATURAL GAS PROCESSING PLANTS

This chapter presents the causes for equipment leaks from natural gas processing plants, and provides emission estimates for "model" facilities in the processing segment of the oil and natural gas industry. Methods that are designed to reduce equipment leak emissions are presented, along with our recommended RACT, and the associated VOC emission reductions and cost impacts for equipment leaks from natural gas processing plants.

This CTG and the recommended RACT included in this CTG replaces the following: *Guideline Series. Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants.* December 1983. EPA-450/3-83-007.

8.1 Applicability

For purposes of this CTG, the emissions and emission controls discussed herein would apply to the group of all equipment (except compressors and sampling connection systems) within a process unit located at a natural gas processing plant in VOC service or in wet gas service, and any device or system that is used to control VOC emissions (e.g., a closed vent system). For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, the piece of equipment must contain or contact the field gas before the extraction step at a natural gas processing plant. Equipment is defined as each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service.

8.2 Process Description and Emission Sources

8.2.1 Process Description

Natural gas processing involves the removal of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. The types of process equipment used to separate the liquids are separators, glycol dehydrators, and amine treaters. In addition, centrifugal and/or reciprocating compressors are used to pressurize and move the natural gas from the processing facility to the transmission stations.

There are several potential sources of equipment leak emissions at natural gas processing plants. Equipment such as pumps, pressure relief devices, valves, flanges, and other connectors are potential sources that can leak due to seal failure. Other sources, such as open-ended lines and valves may leak for reasons other than faulty seals, such as an improperly installed cap on an open-ended line. In addition, corrosion of welded connections, flanges, and valves may also be a cause of equipment leak emissions. The following subsections describe potential equipment leak sources and the magnitude of the VOC emissions from natural gas processing plants.

Due to the large number of valves, pumps, and other equipment within natural gas processing plants, VOC emissions from leaking equipment can be significant (chapter 2.2 of the 1983 CTG[126] presents a description of these equipment components and is not repeated here).

8.2.2 Equipment Leak Emission Data and Emission Factors

8.2.2.1 Summary of Major Studies and Emission Factors

The 2012 NSPS TSD evaluated emissions data from equipment leaks collected from chemical manufacturing and petroleum production to assist in the development of control strategies for reducing VOC emissions from these sources.[127,128,129] Table 8-1 presents a list of the studies consulted along with an indication of the type of information contained in the study. In addition to these sources, we evaluated the peer reviewer and public comments received on the EPA's white paper, "Oil and Natural Gas Sector Leaks."[130]

[126] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC, 27711. *Guideline Series. Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants.* December 1983. EPA-450/3-83-007.
[127] Memorandum from David Randall, RTI and Karen Schaffner, RTI to Randy McDonald, U.S. Environmental Protection Agency. *Control Options and Impacts for Equipment Leaks: Chemical Manufacturing Area Source Standards*. September 2, 2008.
[128] Memorandum from Kristen Parrish, RTI and David Randall, RTI to Karen Rackley, U.S. Environmental Protection Agency. *Final Impacts for Regulatory Options for Equipment Leaks of VOC on SOCMI*. October 30, 2007.
[129] Memorandum from Kristen Parrish, RTI, David Randall, RTI, and Jeff Coburn, RTI to Karen Rackley, U.S. Environmental Protection Agency. *Final Impacts for Regulatory Options for Equipment Leaks of VOC in Petroleum Refineries*. October 30, 2007.
[130] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Leaks. Report for Oil and Natural Gas Sector Leaks Review Panel*. Office of Air Quality Planning and Standards (OAQPS). April 2014.

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

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[r]
Protocol for Equipment Leak Emission Estimates[a]	EPA	1995	None	X	X
Methane Emissions from the Natural Gas Industry: Equipment Leaks[b]	EPA/GRI	1996	Nationwide	X	X
Greenhouse Gas Reporting Program[c]	EPA	2014	Nationwide	X	X
Inventory of Greenhouse Gas Emissions and Sinks[d]	EPA	Annual	Nationwide	X	
Methane Emissions from the Natural Gas Industry[e,f,g,h]	EPA/GRI	1996	Nationwide	X	X
Methane Emissions from the U.S. Petroleum Industry[i]	EPA	1996	Nationwide	X	
Methane Emissions from the U.S. Petroleum Industry[j]	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States[k]	Western Regional Air Partnership	2005	Regional	X	X
Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories[l]	Central States Regional Air Partnership	2008	Regional	X	X
Oil and Gas Producing Industry in Your State[m]	Independent Petroleum Association of America	2009	Nationwide		
Emissions from Natural Gas Production in the Barnett Shale and Opportunities for Cost-effective Improvements[n]	Environmental Defense Fund	2009	Regional	X	X
Emissions from oil and Natural Gas Production Facilities[o]	Texas Commission for Environmental Quality	2007	Regional	X	X
Petroleum and Natural Gas Statistical Data[p]	U.S. Energy Information Administration	2007-2009	Nationwide		

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[r]
Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations[q]	EPA	1999		X	X

[a] U.S. Environmental Protection Agency, *Protocol for Equipment Leak Emission Estimates*. Office of Air Quality Planning and Standards. Research Triangle Park, NC. November 1995. EPA-453/R-95-017. Available at http://www.epa.gov/ttn/chief/efdocs/equiplks.pdf.
[b] Gas Research Institute (GRI)/U.S. Environmental Protection Agency. *Research and Development, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*. June 1996 (EPA-600/R-96-080h).
[c] U.S. Environmental Protection Agency. Greenhouse Gas Reporting Program. (Annual Reporting; Current Data Available for 2011-2013). 2014.
[d] U.S Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html.
[e] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 2: Technical Report*. EPA-600/R-96-080b. June 1996.
[f] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 3: General Methodology*. EPA-600/R-96-080c. June 1996.
[g] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 5: Activity Factors*. EPA-600/R-96-080e. June 1996.
[h] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 6: Vented and Combustion Source Summary Emissions*. EPA-600/R-96-080f. June 1996.
[i] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the U.S. Petroleum Industry, Draft Report*. June 14, 1996.
[j] ICF Consulting. *Estimates of Methane Emissions from the U.S. Oil Industry*. Prepared for the U.S. Environmental Protection Agency. 1999.
[k] ENVIRON International Corporation. *Oil and Gas Emission Inventories for the Western States*. Prepared for Western Governors' Association. December 27, 2005.
[l] 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.
[m] Independent Petroleum Association of America. *Oil and Gas Producing Industry in Your State*.
[n] Armendariz, Al. *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements*. Prepared for Environmental Defense Fund. January 2009.
[o] Eastern Research Group, Inc. *Emissions from Oil and Gas Production Facilities*. Prepared for the Texas Commission on Environmental Quality. August 31, 2007.
[p] U.S. Energy Information Administration. *Annual U.S. Natural Gas Wellhead Price*. U.S. Energy Information Administration. Natural Gas Navigator. Retrieved online on 12 Dec 2010 at http://www.eia.doe.gov/dnav/ng/hist/n9190us3a.htm.
[q] Eastern Research Group, Inc. *Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operation*. Prepared for the U.S. Environmental Protection Agency. September 1999.
[r] An "X" in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

8.2.2.2 Natural Gas Processing Model Plant

Natural gas processing plants can consist of a variety of combinations of process equipment and components. In order to conduct analyses to be used in evaluating potential options to reduce emissions from leaking equipment, the 2011 NSPS TSD and the 2012 NSPS TSD used a model plant approach.

Information related to equipment counts were obtained from a natural gas industry report.[131] This document provided average equipment counts for gas production and gas processing segments. These average counts were used to develop a model plant. These equipment counts are consistent with those contained in the EPA's analysis to estimate methane emissions conducted in support of the GHGRP. The natural gas processing model plant is discussed in the following section. A summary of the model plant production equipment counts for a gas processing facility is provided in Table 8-2.

Table 8-2. Equipment Counts for Natural Gas Processing Model Plant

Equipment	Equipment Count (non-compressor equipment)
Valves	1,392
Connectors	4,392
Open-Ended Lines (OEL)	134
Pressure Relief Valve (PRV)	29

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-13, June 1996. (EPA-600/R-96-080h)

8.2.2.3 Natural Gas Processing Model Plant Emissions

Overview of Approach

The EPA gathered equipment leak data and cost information for the development of the proposed National Uniform Emission Standards for Equipment Leaks rule (58 FR 17898, March 26, 2012). These Uniform Standards data were used to estimate baseline emissions for a natural

[131] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*. Table 4-13, June 1996. (EPA-600/R-96-080h).

gas processing model plant for the 2012 NSPS STSD and provide the baseline and controlled emission options for processing plants presented in this CTG.[132,133]

The baseline emissions were defined as being equivalent to a 40 CFR part 60, subpart VV (subpart VV) leak detection and repair (LDAR) program, which represents the same set of requirements that apply to natural gas processing plants under 40 CFR part 60, subpart KKK (subpart KKK). The 2012 NSPS requires the implementation of 40 CFR part 60, subpart VVa (subpart VVa) and currently applies to natural gas processing plants constructed or modified after August 23, 2011. It is assumed that natural gas processing plants constructed, reconstructed or modified on or before August 23, 2011 currently still comply with subpart KKK, which is similar to the control level of subpart VV. We evaluated requiring a similar subpart VVa level of control to these plants as was required under the 2012 NSPS. We used leak frequency data (refers to the estimated percentage of equipment that will be found leaking at a given leak definition) to calculate emission estimates, in addition to several other sources of information (including the Protocol for Equipment Leak Emissions Estimates and industry data).[134] Table 8-3 provides a summary of the equipment leak frequency data used for the natural gas processing model plant. Emission factors are the estimated leak rates for an equipment type at a given leak definition and are normally given in kg/hr/piece of equipment. Table 8-4 provides a summary of the VOC equipment leak emission factors representing the subpart VVa level of control that was used for the natural gas processing model plant.

[132] Memorandum from Cindy Hancy, RTI International to Jodi Howard, EPA/OAQPS. *Analysis of Emission Reduction Techniques for Equipment Leaks*. December 21, 2011.
[133] 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 the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.
[134] U.S. Environmental Protection Agency. *Protocol for Equipment Leak Emission Estimates*. November 1995. EPA-453/R-95-017.

Table 8-3. Summary of Equipment Leak Frequency for Natural Gas

LDAR Program[a]	Valves	Connectors
Baseline	1.18/1.18	NA
Valves	5.95/1.91	NA
Connectors	NA	1.70/0.81

NA = Not Applicable; no equipment leak frequency percent data were available.
Data Source: Memorandum from Cindy Hancy, RTI International to Jodi Howard, EPA/OAQPS, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011, Table 5.
[a] The leak frequencies provided in the tables are presented as initial leak frequency and subsequent leak frequency under the subpart VVa level of control.

Table 8-4. Summary of VOC Equipment Leak Emission Factors for the Natural Gas Processing Model Plant

Component	Uncontrolled (kg/comp-hr)	Baseline (kg/comp-hr)[a]	Subpart VVa Control Level (kg/comp-hr)[b]
Valves	3.71E-04	2.24E-04	8.85E-05
Connectors	1.04E-04	1.04E-04	3.95E-05
OEL	2.30E-03	7.34E-05	NA
PRV	1.60E-01	9.80E-02	NA

NA = Not Applicable
Data Source: Memorandum from Cindy Hancy, RTI International to Jodi Howard, EPA/OAQPS, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011, Table 7.
[a] The baseline option is assumed to be equivalent to a subpart VV LDAR program.
[b] Assumed to be equivalent to a subpart VVa LDAR program.

8.3 Available Controls and Regulatory Approaches

8.3.1 Available VOC Emission Control Options

The EPA has determined that leaking equipment, such as valves, pumps, and connectors are a significant source of VOC emissions from natural gas processing plants. The following subsections describe the techniques used to reduce emissions from these sources.

8.3.1.1 Leak Detection and Repair Program

The most commonly employed control technique for equipment leaks is the implementation of an LDAR program. Emission reductions from implementing an LDAR program can potentially reduce product losses, increase safety for workers and operators, decrease exposure of hazardous chemicals to the surrounding community, and reduce emissions fees. An effective LDAR program will target leaking equipment by establishing leak definitions and require work practices to mitigate the leaks, such as monitoring frequencies for specific types of equipment (i.e., valves, pumps, and connectors). Other elements of an effective LDAR program include:

(1) Identifying Equipment,
(2) Monitoring Equipment,
(3) Repairing Equipment,
(4) Recordkeeping, and
(5) Reporting.

The primary sources of equipment leak emissions from natural gas processing plants are valves and connectors because these are the most prevalent equipment and can number in the thousands (see Table 8-2). The major cause of emissions from valves and connectors is a seal or gasket failure due to normal wear or improper maintenance. A leak is detected whenever the measured concentration exceeds the threshold standard (i.e., leak definition) for the applicable regulation. Leak definitions vary by regulation, equipment type, and service (e.g., light liquid, heavy liquid, gas/vapor). Most NSPS regulations that were promulgated prior to 2007 have a valve leak definition of 10,000 ppm, while many National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations use a 500 ppm leak definition for valves or 1,000-ppm leak definition for other equipment such as pumps. In addition, some regulations define a leak based on visual inspections and observations (such as fluids dripping, spraying, misting, or clouding from or around equipment), sound (such as hissing), and smell.

For many NSPS and NESHAP regulations with leak detection provisions, the primary method for monitoring to detect leaking equipment is EPA Reference Method 21 (40 CFR part 60, appendix A-7). Method 21 is a procedure used to detect VOC leaks from equipment using a toxic vapor analyzer (TVA) or organic vapor analyzer (OVA).

A second method for monitoring to detect leaking components is optical gas imaging (OGI) using an infrared (IR) camera. The IR camera may be passive or active. The operator uses the passive IR cameras to scan an area to produce images of equipment leaks from a number of sources. Active IR cameras point or aim an IR beam at a potential source to indicate the presence of gaseous emissions (equipment leaks). An equipment leak is any emissions that are visualized by an OGI instrument. The optical imaging camera can be very efficient in monitoring multiple pieces of equipment in a short amount of time. However, the optical imaging camera cannot quantify the amount or concentration of the equipment leak.

Acoustic leak detectors measure the decibel readings of high frequency vibrations from the noise of leaking fluids from equipment leaks using a stethoscope-type device. The decibel reading, along with the type of fluid, density, system pressure, and component type can be correlated into leak rate by using algorithms developed by the instrument manufacturer. The acoustic detector does not decrease the monitoring time because components are monitored separately, like the OVA or TVA monitoring. The accuracy of the measurements using the acoustic detector can also be questioned due to the number of variables used to determine the equipment leak emissions.

In addition, other monitoring tools, such as soap solution and electronic screening devices, can be used to find equipment leaks from certain types of equipment. Other factors that can improve the efficiency of an LDAR program include training programs for equipment monitoring personnel and tracking systems that address the cost efficiency of alternative equipment (e.g., competing brands of valves in a specific application).

Subpart VVa LDAR Program

One LDAR option to control VOC emissions from natural gas processing plant equipment leaks is the implementation of the subpart VVa LDAR program. This program is similar to the subpart VV monitoring program (requirements are cross-referenced in subpart KKK), but finds more leaks due to the lower leak definition, increased monitoring frequency, and the addition of connectors to the components being monitored, thereby achieving better emission reductions.

Description

The subpart VVa LDAR program requires the monitoring of pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines, valves, and connectors. These components are monitored with an OVA or TVA to determine if a component is leaking and measures the concentration of the organics if the component is leaking. Connectors and valves have a leak definition of 500 ppm. Valves are monitored monthly, connectors are monitored annually, and open-ended lines and pressure relief valves must be monitored within five days after a pressure release event to ensure they are operating without any detectable emissions (e.g. at a concentration less than 500 ppm above background). Compressors are not included in this leak detection and repair option and are regulated separately.

Control Effectiveness

The control effectiveness of an LDAR program is based on the frequency of monitoring, leak definition, frequency of leaks, percentage of leaks that are repaired, and the percentage of reoccurring leaks. The control effectiveness of a leak program can vary from 45 to 96 percent and is dependent on the frequency of monitoring and the leak definition.[135] Descriptions of the frequency of monitoring and leak definition are described further below.

Monitoring Frequency. The monitoring frequency is the number of times each piece of equipment is checked for leaks over a given period of time. With more frequent monitoring, leaks are found and repaired sooner, thus providing higher control effectiveness.

Leak Definition. The leak definition describes the local VOC concentration at the surface of an equipment source where indications of VOC emissions are present. The leak definition is an instrument meter reading, in parts per million based on a reference compound. Decreasing the leak definition generally increases the number of leaks found during a monitoring period, which generally increases the number of leaks that are repaired.

The 2012 NSPS STSD calculated incremental emission reductions from the baseline requirements (assuming that an LDAR program equivalent to the subpart VV/subpart KKK LDAR program is currently implemented at natural gas processing plants), and the leak frequency and emission factors from a supporting document for the Equipment Leak Uniform Standards were used to calculate the emission reductions and costs. The natural gas processing plant component counts (see Table 8-2) were obtained from an EPA/GRI document.[136] The incremental VOC emission reductions for implementing a subpart VVa leak detection and repair program (as determined in the 2012 NSPS STSD) for the natural gas processing model plant was calculated to be 13 percent.

[135] 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 the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

[136] GRI/EPA Research and Development. *Methane Emissions from the Natural Gas Industry; Volume 8: Equipment Leaks*. June 1996. EPA-600/R-96-080h.

Cost Impacts

Table 8-5 presents a summary of the incremental capital and annual costs and the cost of control (estimated in the 2012 NSPS STSD) from baseline (subpart VV) to implementing subpart VVa for the gas processing model plant. The costs obtained from the 2012 NSPS TSD have been converted to 2012 dollars from 2008 dollars using the Federal Reserve Economic Data GDP Price Deflater (Change in GDP: Implicit Price Deflator from 2008 to 2012 (5.69 percent)).[137]

Table 8-5. Summary of the Gas Processing Model Plant VOC Cost of Control for the Subpart VVa Option

Annual VOC Emission Reductions (tpy)	Capital Cost ($2012)	Annual Cost ($2012/year)	VOC Cost of Control ($2012/ton)	
			Without savings	With savings[a]
4.56	$8,499	$12,959	$2,844	$2,010

[a] With savings calculated assuming the natural gas (82.9 percent methane) from the methane reduction has a value of $4/Mscf. The VOC/methane ratio was assumed to be 0.278.

Table 8-6 provides a summary of the capital and annual costs and the cost of control on a component basis for the natural gas processing model plant.

Table 8-6. Summary of the Gas Processing Component VOC Cost of Control for the Subpart VVa Option

Component	Annual VOC Emission Reductions (tpy)	Capital Cost ($2012)	Annual Cost ($2012/year)	VOC Cost of Control ($2012/ton)	
				Without Savings	With Savings[a]
Valves	1.82	$5,231	$9,280	$5,095	$4,261
Connectors	2.74	$8,374	$4,405	$1,610	$776

[a] With savings calculated assuming the natural gas (82.9 percent methane) from the methane reduction has a value of $4/Mscf. The VOC/methane ratio was assumed to be 0.278.

8.3.1.2 Leak Detection and Repair Program with Optical Gas Imaging

Another option to control VOC emissions is the implementation of a program that uses OGI to detect equipment leaks. The alternative work practice for equipment leaks in §60.18(g) of

[137] U.S. Bureau of Economic Analysis, Gross Domestic Product: Implicit Price Deflator (GDPDEF), retrieved from FRED, Federal Reserve Bank of St. Louis https://research.stlouisfed.org/fred2/series/GDPDEF. March, 26, 2015.

40 CFR part 60, subpart A allows the use of an OGI instrument to monitor equipment for leaks. This option is currently available for monitoring equipment leaks from valves, pumps, connectors and other equipment that is subject to monitoring in subpart VVa.

The alternative work practice requires periodic monitoring, based on the detection sensitivity level (grams per hour), of the affected equipment using OGI and an annual monitoring survey of the affected equipment using a Method 21. Method 21 monitoring allows the facility to determine the concentration of a leak and to then use emission factors found in the EPA's emissions leak protocol to quantify emissions from equipment leaks, because the OGI system can only provide the presence of the equipment leaks.

Modeling results, conducted in support of the alternative work practice standard, showed a work practice repeated bimonthly with a detection limit of 60 g/hr range was equivalent to existing Method 21 work practices. The model generated different detection limits for the 500 and 10,000 ppm thresholds in existing rules. Based on modeling, the alternative work practice standard reflects the mass detection limit for 500 ppm, thus, providing equivalency for both 500 and 10,000 ppm thresholds.[138] The alternative work practice option is assumed to have the same control effectiveness as the subpart VVa monitoring program.

8.3.2 Existing Federal, State and Local Regulations

8.3.2.1 Federal Regulations that Specifically Require Control of VOC Emissions

Federal regulations that regulate VOC emissions from equipment leaks at natural gas processing plants include 40 CFR part 60 subpart OOOOa, subpart OOOO, and subpart KKK; and the 1983 CTG document (established a recommended RACT for VOC for natural gas processing plants at a level of control equivalent to subpart KKK).

8.3.2.2 State and Local Regulations that Specifically Require Control of VOC Emissions

States may have permitting restrictions on VOC emissions that may apply to an emissions source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed,

[138] 73 FR 78199, December 22, 2008.

what emission limits must be met, and often how the source must be operated. To ensure that sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

We assume that all states currently regulate equipment leaks at existing natural gas processing plants at the 1983 CTG document and subpart VV level of control.

8.4 Recommended RACT Level of Control for Equipment Leaks from Equipment at Natural Gas Processing Plants

As discussed in section 8.3.2 of this chapter, existing federal, state and local regulations already require the reduction of VOC emissions using an LDAR program. The 2012 NSPS requires a 40 CFR part 60 subpart VVa LDAR monitoring program for processing plants. The 2012 NSPS reported a cost of control for natural gas processing plants to be $2,844 per ton of VOC removed for the 40 CFR part 60 subpart VVa option.

Based on costs and existing LDAR programs that are already employed at natural gas processing plants, we recommend that RACT for natural gas processing plants be the implementation of an LDAR program equivalent to what is required under 40 CFR part 60 subpart VVa for equipment (with the exception of compressors and sampling connection systems) in VOC service. This RACT recommendation would increase the stringency from the currently implemented LDAR programs at most existing natural gas processing plants (that were built prior to 2012) in VOC service by lowering the leak definitions, increasing the monitoring frequency, and including additional equipment. The subpart VVa leak detection and repair program requires the annual monitoring of connectors using an OVA or TVA (500 ppm leak definition), monthly monitoring of valves (500 ppm leak definition) and requires open-ended lines and pressure relief devices to operate with no detectable emissions (less than 500 ppm above background). The estimated annual incremental VOC emission reductions for the recommended RACT for a natural gas processing plant was estimated to be 4.56 tpy (see Table 8-5 of this chapter). The annual VOC emission reductions assume a baseline level of control equivalent to the 40 CFR part 60, subpart VV LDAR program. Table 8-5 presents the gas processing model plant VOC cost of control for the recommended RACT. The costs assume a baseline level of control equivalent to the 40 CFR part 60, subpart VV LDAR program. The recommended RACT VOC cost of control is estimated to be $2,844 per ton of VOC reduced without savings and $2,010 with savings.

In summary, we recommend the following RACT for equipment leaks at natural gas processing plants:

> RACT for Equipment Leaks at Natural Gas Processing Plants: We recommend the implementation of an LDAR program equivalent to what is required under 40 CFR part 60 subpart VVa for equipment (with the exception of compressors and sampling connection systems) in VOC service.

8.5 Factors to Consider in Developing Equipment Leak Compliance Procedures

Existing natural gas processing plants that would be subject to the recommended RACT are already subject to an LDAR program and the basic elements of the LDAR program for the facility are in place. However, the LDAR program would need to be modified to increase the stringency from the currently implemented LDAR program by requiring annual monitoring of connectors using an OVA or TVA (500 ppm leak definition), and lowering the leak definition for valves (500 ppm). As with the currently implemented LDAR program, to ensure that equipment in VOC service that leak at natural gas processing plants are properly monitored and repaired under the LDAR RACT recommendations, we suggest that air agencies specify monitoring frequency, equipment repair, and recordkeeping and reporting requirements to document compliance.

Monitoring frequencies vary according to the applicable regulation, but are typically weekly, monthly, quarterly and yearly. The monitoring frequency depends on the equipment type and periodic leak rate for the equipment. For each piece of equipment that is found to be leaking, the first attempt at repair should be made within a reasonable period of time, such as no later than five calendar days after each leak is detected. First attempts at repair include, but are not limited to, the following best practices, where practicable and appropriate:

(1) Tightening of bonnet bolts,
(2) Replacement of bonnet bolts,
(3) Tightening of packing gland nuts, and
(4) Injection of lubricant into lubricated packing.

Once the equipment is repaired, it should be re-monitored over the next several days to ensure the leak has been successfully repaired. Another method that can be used to repair equipment is to replace the leaking equipment with a "leakless" equipment or other technologies.

When implementing an LDAR program, we recommend that air agencies consider including recordkeeping requirements that require owner/operators of subject facilities to maintain a list of identification numbers for all equipment subject to an equipment leak regulation. A list of equipment that is designated as "unsafe to monitor" should also be maintained with an explanation/review of conditions for the designation. Detailed schematics, equipment design specifications (including dates and descriptions of any changes), and piping and instrumentation diagrams should also be maintained with the results of performance testing and leak detection monitoring.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

9.0 FUGITIVE EMISSIONS FROM WELL SITES AND GATHERING AND BOOSTING STATIONS

Fugitive emissions from components in the oil and natural gas industry are a source of VOC emissions. This chapter discusses the sources of fugitive emissions, and provides VOC emission estimates for well sites and gathering and boosting stations in the production segment (located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or point of custody transfer to an oil pipeline). This chapter also presents a description of programs that are designed to reduce fugitive emissions, along with costs, and emission reductions. Finally, this chapter provides a discussion of our recommended RACT and the estimated VOC emission reductions and costs for fugitive emissions from well sites and gathering and boosting stations in the production segment.

9.1 Applicability

For purposes of this CTG, the emissions and programs to control emissions discussed herein would apply to the collection of fugitive emissions components at well sites with an average production of greater than 15 barrel equivalents per well per day (15 barrel equivalents)[139] and the collection of fugitive emissions components at gathering and boosting stations in the production segment.

For the purposes of this CTG, fugitive emission reduction recommendations would not apply to well sites that only contain wellheads.

Fugitive emissions, for the purposes of applicability of this CTG, means those emissions from a stationary source that could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening. Equipment leak emissions at natural gas processing plants are covered under chapter 8 of this document.

[139] Natural gas production converted to barrel equivalents uses the conversion of 0.178 barrels of crude oil to 1000 cubic feet of natural gas. Based upon conversion factor used for the no longer in service U.S. EIA Financial Reporting System for Major Energy Producers.

9.2 Fugitive Emissions Description and Data

9.2.1 Fugitive Emissions Description

There are several potential sources of fugitive emissions throughout the oil and natural gas industry. Fugitive emissions occur when connection points are not fitted properly or when seals and gaskets start to deteriorate. Changes in pressure, temperature, or mechanical stresses can also cause components or equipment to emit fugitive emissions. Poor maintenance or operating practices, such as improperly reseated PRVs or thief hatches on controlled storage vessels that are left open after sampling, are also potential sources of fugitive emissions. Potential sources of fugitive emissions include agitator seals, connectors, pump diaphragms, flanges, instruments, meters, open-ended lines (OELs), pressure relief devices such as PRVs, pump seals, valves, or improperly controlled liquid storage tanks. These fugitive emissions do not include devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pneumatic pumps, insofar as the natural gas and associated VOC emissions discharged from the device's vent is not considered a fugitive emission.

For the purposes of our RACT analysis for fugitive emissions from components and equipment, we differentiated between the definition of "equipment" for purposes of controlling equipment leaks for oil and natural gas processing plants in subpart OOOO[140] and the definition we use for the purposes of addressing fugitive emissions from oil and natural gas well sites and gathering and boosting stations. For purposes of our RACT analysis, "fugitive emissions component(s)" are the focus of our analysis for fugitive emissions from oil and natural gas well sites and gathering and boosting stations. The definition for "fugitive emissions component" is as follows:

> *Fugitive emissions component* means any component that has the potential to emit fugitive emissions of VOC at a well site or gathering and boosting station, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not already subject to equipment and fugitive emissions monitoring, thief hatches or other openings on a controlled storage vessel, compressors, instruments and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions

[140] 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.

components, insofar as the natural gas and associated VOC emissions discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

9.2.2. Emission Data and Emission Factors

9.2.2.1 Summary of Major Studies and Emission Factors

In April of 2014, we published a white paper[141] which summarized our current understanding of VOC fugitive emissions at onshore oil and natural gas production, processing and transmission and storage facilities (referred to herein as the "equipment leaks white paper"). The equipment leaks white paper also outlined our 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 equipment leaks white paper provided a summary of fugitive emission studies at oil and natural gas well sites and gathering and boosting stations in the production segment. Throughout the development of this CTG, the EPA evaluated a variety of emissions data and emission reduction options for fugitive emissions. Many of the studies in the equipment leaks white paper were consulted. Table 9-1 presents a list of the studies consulted along with an indication of the type of information contained in each study.

Table 9-1. Major Studies Reviewed for Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[m]
Protocol for Equipment Leak Emission Estimates[a]	EPA	1995	None	X	X
Methane Emissions from the Natural Gas Industry: Equipment Leaks[b]	EPA/GRI	1996	Nationwide	X	X
Greenhouse Gas Reporting Program[c]	EPA	2013	Facility	X	
Inventory of Greenhouse Gas Emissions and Sinks[d]	EPA	Annual	Regional	X	
Measurements of Methane Emissions at Natural Gas	Multiple Affiliations,	2013	Nationwide	X	X

[141] 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.

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[m]
Production Sites in the United States[e]	Academic and Private				
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, CO[g]	ARCADIS/Sage Environmental Consulting/ EPA	2012	Colorado	X	X
Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs Using Infrared 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 Methane 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 Methane 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	X	X

[a] U.S. Environmental Protection Agency. *Protocol for Equipment Leak Emission Estimates*. Office of Air Quality Planning and Standards. Research Triangle Park, NC. November 1995. EPA-453/R-95-017. Available at http://www.epa.gov/ttn/chief/efdocs/equiplks.pdf.
[b] U.S. Environmental Protection Agency/GRI. Research and Development, *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*. June 1996 (EPA-600/R-96-080h).
[c] U.S. Environmental Protection Agency. Greenhouse Gas Reporting Program. (Annual Reporting; Current Data Available for 2011-2013). 2014.
[d] U.S Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html.
[e] Allen, David, T., et al. *Measurements of methane emissions at natural gas production sites in the United States*. Proceedings of the National Academy of Sciences (PNAS) 500 Fifth Street, NW NAS 340 Washington, DC 20001 USA. October 29, 2013. 6 pgs.

[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 Leak Detection and Repair Programs using Infrared 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. *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 Plan*ts. 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.
[m] An "X" in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

9.2.2.2 Model Plants

Facilities in the oil and natural gas industry consist of a variety of combinations of process equipment and components. This is particularly true in the production segment of the 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 fugitive emissions from well sites and gathering and boosting stations, a model plant approach was used. The following sections discuss the creation of these model plants.

<u>Oil and Natural Gas Production Well Sites</u>

Oil and natural gas production varies from one site to the next. 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 site. A well site is a site where the production, extraction, recovery, lifting, stabilization, separation, and/or treating of petroleum and/or natural gas (including condensate) occurs. These sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) that have associated components that may be sources of fugitive emissions associated with these operations. A well site can serve one well on a pad or multiple wells on a pad. Therefore, the number of components with potential for fugitive emissions can vary depending on the number of wells at the site.

Model plants were developed using the average number of wells associated with a well site using data from the Drillinginfo HPDI database.[142] 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 pad. 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.[143]

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, we assumed the two wells were 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. Wells producing in 2012 numbered about 1.27 million. The second algorithm processed the results of the first such that a well 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. We did not visually inspect every site in the U.S. linked to a 2012 completion or recompletion as

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[142] Drilling Information, Inc. 2011. *DI Desktop.* 2011 Production Information Database.
[143] See the website <http://www.r-project.org/> for more information on R (The R Project for Statistical Computing). R is a free software environment for statistical computing and graphics.

they numbered greater than 20,000. Instead, 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.

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 9-2 shows the high-level results of these analyses.

Table 9-2. Estimated Average Number of Wells per Site of New Well Completion in 2012

Assumed Well Site Size	No. of Well Sites	No. of Wells at Sites	Average of Wells Per Site
One Acre	29,213	50,599	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 9-3 masks variation by basins and well types. Table 9-3 presents more detail along these dimensions for the assumed two-acre well site.

Table 9-3. Estimated Average Number of Wells per Two-Acre Site of New Well Completions and Recompletions 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 HF	Oil Well Completions Not HF	Oil Well Completions All	Natural Gas Well Completions HF	Natural Gas Well Completions Not HF	Natural Gas Well Completions All	Total
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
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

HPDI Basin	No. Of Sites	Oil Well Completions HF	Oil Well Completions Not HF	Oil Well Completions All	Natural Gas Well Completions HF	Natural Gas Well Completions Not HF	Natural Gas Well Completions All	Total
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
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**

The data presented in Table 9-3 indicates that the concentration of wells at production sites varies greatly by basin. However, the analysis also indicates that most wells sites have relatively few or no co-located wells, which brings the national average of 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, 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.

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 underestimate 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 acres might overestimate 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 longitude values 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. Therefore, based on this analysis, the model plants for oil and natural gas well sites are based on a well site with 2 wells.

Baseline model plant emissions for natural gas and oil production well sites were calculated using the fugitive emissions equipment counts from the GHG Inventory, derived from GHGRP, EPA/GRI and 40 CFR part 98, subpart W tables, and the component oil and natural gas production emission factors from AP-42.[144] Annual emissions were calculated assuming 8,760 hours of operation each year. We used equipment count data from the EPA GHG Inventory to calculate the average counts of production equipment located at a well site. The types of production equipment located at a well site include: gas wellheads, separators, meters/piping, heaters, and dehydrators. The types of components that are associated with these production equipment types include: valves, connectors, open-ended lines, and pressure relief valves. Component counts for each of the equipment items were calculated using the average component counts for gas production equipment in the Eastern U.S. and the Western U.S. Fractions of components were rounded up to the nearest integer.

For natural gas well sites, the model plant was developed using the average equipment and fugitive emissions components counts for natural gas production data from the EPA/GRI report and the 2016 GHG Inventory. The average equipment count for a natural gas well was estimated by using the average equipment counts per well in the 2016 GHG Inventory (based on GHGRP data), and by weighing the average component counts per equipment for the Eastern and Western U.S. data sets for gas production equipment. This resulted in 2 separators, 3 meters/piping, 1 in-line heater, and 1 dehydrator per well. The total natural gas well site

[144] U.S. Environmental Protection Agency. *Protocol for Equipment Leak Emission Estimates*. Table 2-4. November 1995. EPA-453/R-95-017.

equipment counts were calculated by multiplying the average well equipment 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 equipment items were calculated using the average component counts for production equipment in the Eastern U.S. and the Western U.S. from the EPA/GRI study. The total number of fugitive emissions components was calculated by multiplying the rounded equipment counts by the component count per equipment and rounding to the nearest integer. Table 9-4 presents a summary of the fugitive emissions component counts for natural gas well sites.

For oil well sites, two model plants were developed in order to account for emissions variability. One oil well model plant was developed for oil wells with a gas-to-oil ration less than 300 standard cubic feet of gas per stock barrel of oil (GOR less than 300) and another model plant was developed for oil wells with a gas-to-oil ratio greater than or equal to 300 standard cubic feet of gas per stock of barrel oil (GOR greater than or equal to 300).

The equipment count for the oil well model plant with a GOR less than 300 consists of 2 oil wellheads, 1 separator, 1 header and 1 heater/treater. These equipment counts were obtained from 2016 GHG Inventory data. The component counts for these equipment types were obtained from Table W-1C of subpart W and are the weighted average component counts for onshore production equipment in the Eastern U.S. and Western U.S.

The equipment count for the oil well model plant with a GOR greater than or equal to 300 consists of 2 oil wellheads, 1 separator, 1 header and 1 heater/treater and 3 meters/piping. These equipment counts for separators, headers, and heater/treaters were obtained from the 2016 GHG Inventory data for petroleum systems, while the meter/piping counts were obtained from the 2016 GHG Inventory data for natural gas systems to reflect gas production at the sites.

The component counts for these equipment types were obtained from Table W-1C of subpart W for all but meters/piping, which were obtained from Table W-1B of subpart W. The component counts are the weighted average component counts for onshore production equipment in the Eastern U.S. and Western U.S. The total number of fugitive emissions components for oil well sites equipment (for both model plants) was calculated by multiplying the rounded equipment counts by the component count per piece of equipment and rounding to the nearest integer. Table 9-5 presents a summary of the fugitive emissions component counts for oil well site model plants.

Table 9-4. Average Fugitive Emissions Component Count for Natural Gas Well Site Model Plant

Equipment	Model Plant Equipment Counts	Average Component Count per Equipment[a]				Average Component Count per Model Plant			
		Valves	Connectors	OELs	PRVs	Valves	Connectors	OELs	PRVs
Gas Wellheads	2	9.5	37.0	0.7	0.0	19.0	74.0	1.4	0.0
Separators	2	21.6	68.5	3.7	1.2	43.2	137.0	7.4	2.4
Meters/Piping	3	12.9	47.8	0.5	0.5	38.7	143.4	1.5	1.5
In-Line Heaters	1	14.0	65.0	2.0	1.0	14.0	65.0	2.0	1.0
Dehydrators	1	24.0	90.0	2.0	2.0	24.0	90.0	2.0	2.0
					Total	138.9	509.4	14.3	6.9
					Rounded up Total	139	510	15	7.0

[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 9-5. Average Fugitive Emissions Component Count for Oil Well Site Model Plants

Production Equipment	Model Plant Production Equipment Counts	Average Component Count Per Unit of Production Equipment[a]					Average Component Count Per Model Plant				
		Valves	Flanges	Connectors	OELs	PRVs	Valves	Flanges	Connectors	OELs	PRVs
Oil Well Model Plant (< 300 GOR)[a]											
Oil Wellheads	2	5	10	4	0	1	10	20	8	0	2
Separators	1	6	12	10	0	0	6	12	10	0	0
Headers	1	5	10	4	0	0	5	10	4	0	0
Heater/Treaters	1	8	12	20	0	0	8	12	20	0	0
						Total	29	54	42	0	2
Oil Well Model Plant (≥ 300 GOR)[b]											
Oil Wellheads	2	5	10	4	0	1	10	20	8	0	2
Separators	1	6	12	10	0	0	6	12	10	0	0
Headers	1	5	10	4	0	0	5	10	4	0	0
Heater/Treaters	1	8	12	20	0	0	8	12	20	0	0
Meters/Piping	3	12.9	0	47.8	0.5	0.5	39	0	144	2	2
						Total	68	54	186	2	4

[a] Oil well (<300 GOR) component counts obtained from 40 CFR Part 98, subpart W, Table W-1C.
[b] Oil well (≥300 GOR) component counts obtained from 40 CFR Part 98, subpart W, Tables W-1B and W-1C.

The baseline emissions for the natural gas well site and oil well model plants were calculated using equipment counts for the natural gas well site model plant and the oil and natural gas production AP-42 total organic compound (TOC) emission factors. Annual emissions were calculated assuming 8,760 hours of operation each year. The TOC emissions were converted to VOC using VOC/TOC weight rations in the 2011 Gas Composition Memorandum.[145]. The fugitive VOC emissions for the natural gas well site model plant were determined to be 1.53 tpy of VOC. The fugitive emissions for the oil well site model plant with a GOR less than 300 was determined to be 0.33 tpy of VOC. The fugitive emissions for the oil well site model plant with a GOR greater than or equal to 300 was determined to be 0.73 tpy of VOC. The VOC emission estimates were used to evaluate the potential emission reductions and cost of control of a fugitive emission reduction program. Table 9-6 presents the emission factors for the natural gas and oil production segments. A summary of the equipment counts, average TOC emission factors and VOC emissions for natural gas well and oil well sites are provided in Tables 9-7 and 9-8, respectively.

Table 9-6. Oil and Natural Gas Production Operations Average TOC Emission Factors

Component Type	Component Service	TOC Emission Factor[a] (kg/hr/source)
Valves	Gas	4.5E-03
Flanges	Gas	3.9E-04
Connectors	Gas	2.0E-04
OEL	Gas	2.0E-03
PRV	Gas	8.8E-03

[a] Data Source: EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)

[145] Memorandum to Bruce Moore from Heather Brown. *Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking*. EC/R, Incorporated. July, 2011.

Table 9-7. Estimated Fugitive VOC Emissions for Natural Gas Production Model Plant

Natural Gas Well Site Model Plant Component	Model Plant Component Count[a]	Uncontrolled TOC Emission Factor[b] (kg/hr/comp)	Uncontrolled VOC Emissions (tpy)[c]
Valves	139	0.0045	1.166
Connectors	510	0.0002	0.190
OELs	15	0.002	0.056
PRVs	7	0.0088	0.115
		Total	1.53

[a] Fugitive emissions component count values for model plant are based on a 2-wellhead site 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] VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from the 2011 Gas Composition Memorandum.

Table 9-8. Estimated Fugitive VOC Emissions for Oil Well Site Model Plants

Oil Well Site Model Plant Component	Model Plant Component Count[a]	Uncontrolled Emission Factor[b] (kg/hr/comp)	Uncontrolled VOC Emissions (tpy)[c]
Oil Well Model Plant (< 300 GOR)			
Valves	29	0.0045	0.243
Flanges	54	0.00039	0.039
Connectors	42	0.0002	0.016
OELs	0	0.002	0
PRVs	2	0.0088	0.033
		Total	0.33
Oil Well Model Plant (≥ 300 GOR)			
Valves	68	0.0045	0.571
Flanges	54	0.00039	0.039
Connectors	186	0.0002	0.069
OELs	2	0.002	0.007
PRVs	4	0.0088	0.066
		Total	0.75

[a] Fugitive emissions component count values for model plant are based on a 2-wellhead pad and are rounded to the nearest integer.
[b] TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.
[c] VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from the 2011 Gas Composition Memorandum.

Gathering and Boosting Stations

Gathering and boosting stations are sites that collect natural gas from well sites and direct them to the natural gas processing plants. These stations have similar equipment to well sites; however they are not directly connected to the wellheads. The EPA/GRI document does not have specific equipment counts for the gathering and boosting segment, but does include equipment counts for gathering compressors within the oil and natural gas production data. To estimate the equipment at a gathering and boosting model plant, the weighted averages of equipment counts for the Eastern and Western U.S. data sets for onshore production equipment were calculated. The weighted averages of the data sets were determined to be 11 separators, 7 meters/piping, 5 gathering compressors, 7 in-line heaters, and 5 dehydrators. These average equipment counts were used to create the model plant for gathering and boosting stations. The components for gathering compressors were included in the model plant total counts, but the compressor seals were excluded. Compressors seals are addressed in chapter 5 of this document. Table 9-9 presents a summary of the fugitive emissions component counts for oil and gas gathering and boosting stations.

Baseline emissions were calculated using the component counts and the TOC emission factors for oil and natural gas production (See Table 9-6). Table 9-10 summarizes the baseline emissions for gathering and boosting stations. The average fugitive emissions from a gathering and boosting station were determined to be 9.8 tpy of VOC. The VOC emission estimate was used to evaluate the potential emission reductions and cost of control of a fugitive emissions reduction program.

Table 9-9. Average Component Count for the Oil and Natural Gas Production Gathering and Boosting Station Model Plant

Equipment	Model Plant Equipment Counts	Average Component Count per Equipment[a]				Average Component Count per Model Plant			
		Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves
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

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

Table 9-10. Estimated Fugitive TOC and VOC Emissions for the Oil and Natural Gas Production Gathering and Boosting Station Model Plant

Component	Model Plant Component Count[a]	Component TOC Emission Factor (kg/hr/ component)[b]	VOC Emissions (tons/yr)[c]
Valve	906	0.0045	7.6
Connectors	2,864	0.0002	1.1
OEL	83	0.002	0.3
PRV	48	0.0088	0.8
		Total	9.8

[a] Component counts from Table 9-9.
[b] TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.
[c] VOC emissions are the baseline which were calculated using 0.193 weight ratio for VOC/TOC obtained from the 2011 Gas Composition Memorandum.

9.3 Available Controls and Regulatory Approaches

9.3.1 Available VOC Emission Control Options

The EPA has determined that fugitive emissions from components are a significant source of VOC emissions from well sites and gathering and boosting stations. Based on the review of public and peer review comments on the equipment leaks white paper and the Colorado and Wyoming state rules, the EPA has identified two options for reducing fugitive VOC emissions from components: a fugitive emissions monitoring program based on the use of OGI leak detection combined with repair of fugitive emission components, and a leak monitoring program based on individual component monitoring using Method 21 for leak detection combined with repair of fugitive emission components. These options, as currently being used by industry to reduce fugitive emissions in the oil and natural gas industry, are described below.

9.3.1.1 Fugitive Emission Detection and Repair with Optical Gas Imaging

Description

The reduction of fugitive emissions from oil and natural gas well sites and gathering and boosting stations involves the development and implementation of a fugitive emissions monitoring plan that covers the collection of fugitive emissions components at well sites or gathering and boosting stations. Under this option, monitoring is conducted using OGI, and the company develops and implements a monitoring plan that covers the collection of fugitive emissions components at well sites or compressor stations within a company-defined area. An example monitoring plan would include inspection of the collection of all fugitive emissions components, such as connectors, open-ended lines/valves, pressure relief devices, closed vent systems, compressors, and thief hatches on controlled storage vessels. The plan would include provisions to repair or replace fugitive emissions components if evidence of fugitive emissions is discovered during the OGI survey (e.g., any visible emissions from a fugitive emissions component observed using OGI).

Control Effectiveness

Potential emission reduction percentages from the implementation of an OGI monitoring program varies from 40 to 99 percent.[146] The data supporting these emission reduction percentages are based on the gathering of individual OGI surveys at various oil and natural gas industry 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 assumptions made by the authors. However, the studies supporting these emission reduction percentages 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,[147] which estimated (1) 40 percent reduction for annual OGI monitoring for well production tank batteries with uncontrolled VOC emissions of greater than 6 tpy or less than or equal to 12 tpy; (2) 60 percent reduction for quarterly OGI monitoring for well production tank batteries with uncontrolled VOC emissions of greater than 12 tpy and less than or equal to 50 tpy; and (3) 80 percent reduction for monthly OGI monitoring at well production tank batteries with uncontrolled VOC emissions greater than 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. As noted above, Colorado

[146] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Leaks*, Office of Air Quality Planning and Standards. Research Triangle Park, NC. April 2014. Available at http://www.epa.gov/airquality/oilandgas/2014papers.

[147] Colorado Air Quality Control Commission, *Cost-Benefit Analysis Submitted Per § 24-4-103(2.5), C.R.S. For Proposed Revisions to Colorado Air Quality Control Commission Regulations Number 3 (5 CCR 1001-5) and Regulation Number 7 (5 CCR 1001-9).* February 7, 2014.

estimated that monthly monitoring would achieve 80 percent at well production tank batteries with an uncontrolled VOC emission rate of greater than 50 tpy. We believe, based on our review of the studies, monthly monitoring should achieve much higher emission reductions. Based on information in the studies and EPA's engineering judgment, the potential emission reduction percentages are estimated to be 40 percent for annual monitoring, 60 percent for semiannual monitoring, and 80 percent for quarterly monitoring.

Data from the EPA Protocol document estimates monthly Method 21 monitoring to achieve 87 percent reductions at a leak definition of 10,000 ppm and 92 percent reductions at a leak definition of 500 ppm. Potential emission reductions for annual, semiannual and quarterly monitoring frequencies were calculated using the data from the EPA Protocol document.[148] For quarterly monitoring, the Method 21 data from the EPA Protocol document estimates a 67 percent reduction at a leak definition of 10,000 ppm and an 83 percent reduction at a leak definition of 500 ppm. Using Method 21 data from the EPA Protocol document, we estimated the percent reductions from semiannual monitoring to be 55 percent at a leak definition of 10,000 ppm and 75 percent reduction at a leak definition of 500 ppm. The potential emission reduction percentages for annual monitoring were calculated to be 42 percent at a leak definition of 10,000 ppm and 68 percent at a leak definition of 500 ppm. The OGI camera is capable of viewing leaks at a 500 ppm level, and achieves similar emission reductions as a Method 21 monitoring program. Based on this information, we believe the expected emission reductions from an OGI monitoring and repair program falls somewhere in the 500 and 10,000 ppm range found in the Method 21 monitoring programs, but closer to the 500 ppm level.

A study performed by ICF[149] using data from subpart W, EPA/ GRI, City of Fort Worth Natural Gas Air Quality Study, UT Study - Methane Emissions in the Natural Gas Supply Chain: Production, UT Study - Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States Pneumatic Controllers, and Jonah Energy LLC WCCA Spring Meeting Presentation determined the Year 3 fugitive emission reductions from a quarterly LDAR program to be 78 percent. The data provided in the study supports 40, 60, 80 percent emission reductions for annual, semiannual and quarterly monitoring, respectively.

[148] Memorandum from Bradley Nelson, EC/R to Jodi Howard, EPA/OAQPS/SPPD, *Estimation of Potential Emission Reductions with the Implementation of a Method 21 Monitoring Program*. April 25, 2016.
[149] ICF International. *Leak Detection and Repair Cost-Effectiveness Analysis*. Prepared for Environmental Defense Fund. December 4, 2015. Revised May 2, 2016.

On the basis of the analysis and the data described here, it was concluded that an OGI monitoring program in combination with a repair program can reduce fugitive methane and VOC emissions from these segments by 40 percent on an annual frequency, 60 percent on a semiannual frequency and 80 percent on a quarterly frequency, as well as minimize the loss of salable gas.

To be conservative, we performed a sensitivity analysis using the midpoint between the potential emission reductions that were calculated for each of the Method 21 monitoring frequencies at leak definitions of 10,000 ppm and 500 ppm, which were determined to be 55, 65, and 75 percent for annual, semiannual and quarterly monitoring, respectively. We then compared the potential emission reductions from 40, 60, 80 percent reductions with the Method 21 midpoint reduction percentages of 55, 65 and 75 and found that the annual methane and VOC emission reductions at each of the monitoring frequency intervals were comparable.[150]

Cost Impacts

Costs (2012 dollars) for preparing an OGI emission monitoring and repair plan for a company-defined area (i.e., field or district) were estimated using hourly estimates for each of the monitoring and repair plan elements. The costs are based on the following assumptions:

(1) Labor cost for each of the monitoring plan elements was estimated to be $57.80 per hour.
(2) Reading of the rule and instructions would take one person four hours to complete at a cost of $231.
(3) Development of a fugitive emission monitoring plan would take two and one half people a total of 60 hours to complete at a cost of $3,468.
(4) Initial activities planning are estimated to take two people a total of 8 hours per monitoring event. Cost for annual monitoring was estimated to be $925, semiannual monitoring was estimated to be $1,850, and quarterly monitoring was estimated to be $3,699.
(5) Notification of compliance status was estimated to take one person one hour to complete at a cost of $58 for gathering and boosting stations. For companies that own and operate well sites, the cost of the notification of compliance was estimated to be $58 per well site

[150] See Emission Reduction Comparison – Well Sites.xls, and Emission Reduction Comparison – Compressor Stations.xls in Docket Id. No. EPA-HQ-OAR-2015-0216 for more information.

for each company defined area, which is estimated to operate 22 well sites within the defined area for a total of $1,272.

(6) Cost of a Method 21 monitoring device of $10,800; or cost for OGI monitoring using an outside contractor (assumed to be $600 for a well site and $2,300 for a gathering and boosting station for each survey).

Costs for implementing a fugitive emission monitoring plan for a company-defined area (i.e., field or district) were estimated for each of the monitoring and repair elements. The costs are based on the following assumptions:

(1) Subsequent activities planning are estimated to take two people a total of 16 hours per monitoring event for well sites and two people a total of 24 hours for gathering and boosting stations. For well sites, this cost was divided among the total number of well sites in the company-defined area.
(2) The cost for OGI monitoring using an outside contractor was assumed to be $600 for a well site and $2,300 for a gathering and boosting station for each survey.
(3) Annual repair costs were estimated to be $299 for well sites and $3,436 for gathering and boosting stations per survey. These costs were estimated assuming that 1.18 percent of the components leak and 75 percent are repaired online and 25 percent are repaired offline.
(4) Cost for resurvey of components assumes five minutes per leak at $57.80 per hour for well sites and $2.00 per leak for gathering and boosting stations. This is based on the assumption that a company purchases Method 21 instrumentation (estimated to be $10,800[151]) and is able to perform the resurvey without needing contractors.
(5) Preparation of annual reports was estimated to take one person a total of 4 hours to complete at a cost of $231.

The initial setup cost or capital cost for well sites was calculated by summing up the costs for reading the air agency 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 $16,696 per company-defined areas for annual monitoring,

[151] 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.

$17,620 per company-defined areas for semiannual monitoring and $19,470 per company-defined areas for quarterly monitoring. Assuming that each company owns and operates 22 well sites within a company-defined area[152], the capital cost per well site was estimated to be $759 for annual monitoring, $801 for semiannual monitoring and $855 for quarterly monitoring. For gathering and boosting 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 device was calculated to be $16,753 per facility. For gathering and boosting stations, the capital cost was assumed to be shared with other gathering and boosting stations within the company-defined area. These stations are estimated to be approximately 70 miles apart. Therefore, within a 210 mile radius of a central location, there would be an estimated seven gathering and boosting stations, and the capital cost for each of these stations was estimated to be $2,393.

For well sites and gathering and boosting stations, the annual cost includes: subsequent activities planning, OGI survey by an outside contractor, cost of repair of fugitive emissions found, preparation and submittal of an annual report and the amortized capital cost over 8 years at 7 percent interest. For our analyses, we calculated the annual cost for annual, semiannual and quarterly OGI surveys. The annual cost for annual, semiannual, and quarterly OGI surveying (inclusive of contractor costs, cost of repair of fugitive emissions found, preparation and submittal of an annual report, and amortized capital cost over 8 years at 7 percent interest) was calculated for the production and processing segments. Tables 9-11 through 9-13 present summaries of the cost of control for VOC for the three OGI monitoring frequency options (i.e., annual, semiannual and quarterly).

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

Table 9-11. Summary of the Model Plant VOC Cost of Control for the Annual OGI Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy)[a]	Capital Cost ($2012)[b]	Annual Cost ($2012/year)[c]		Cost of Control ($2012/ton)	
			Without savings	With savings [d]	Without savings	With savings [d]
Natural Gas Well Site	0.61	$759	$1,318	$809	$2,158	$1,324
Oil Well Site (GOR < 300)	0.13	$759	$1,318	$1,204	$9,953	$9,089
Oil Well Site (GOR ≥ 300)	0.30	$759	$1,318	$1,063	$4,380	$3,533
Gathering and Boosting Station	3.91	$2,393	$7,777	$4,518	$1,990	$1,156

[a] Assumes 40 percent reduction with the implementation of annual IR camera monitoring.
[b] The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program divided between an average of 22 well sites per company district. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between seven stations within a company-defined area.
[c] Annual cost for well sites includes annual monitoring and repair cost of $1,191 and amortization of the capital cost over 8 years at 7 percent interest. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of $7,736 and amortization of the capital cost over 8 years at 7 percent interest.
[d] Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as $4 Mcf.

Table 9-12. Summary of the Model Plant VOC Cost of Control for the Semiannual OGI Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) [a]	Capital Cost ($2012)[b]	Annual Cost ($2012/year) [c]		Cost of Control ($2012/ton)	
			Without savings	With savings [d]	Without savings	With savings [d]
Natural Gas Well Site	0.917	$801	$2,285	$1,521	$2,494	$1,660
Oil Well Site (GOR < 300)	0.199	$801	$2,285	$2,114	$11,503	$10,639
Oil Well Site (GOR $\geq$ 300)	0.451	$801	$2,285	$1,903	$5,062	$4,215
Gathering and Boosting Station	5.86	$2,393	$13,534	$8,646	$2,309	$1,475

[a] Assumes 60 percent reduction with the implementation of semiannual IR camera monitoring.
[b] The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program divided between an average of 22 well sites per company district. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between seven stations within a company-defined area.
[c] Annual cost for well sites includes annual monitoring and repair cost of $2,151 and amortization of the capital cost over 8 years at 7 percent interest. 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 percent interest.
[d] Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as $4 Mcf.

Table 9-13. Summary of the Model Plant VOC Cost of Control for the Quarterly OGI Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) [a]	Capital Cost ($2012)[b]	Annual Cost ($2012/year) [c]		Cost of Control ($2012/ton)	
			Without savings	With savings [d]	Without savings	With savings [d]
Natural Gas Well Site	1.222	$885	$4,220	$3,201	$3,453	$2,619
Oil Well Site (GOR < 300)	0.265	$885	$4,220	$3,991	$15,929	$15,064
Oil Well Site (GOR ≥ 300)	0.602	$885	$4,220	$3,710	$7,010	$6,163
Gathering and Boosting Station	7.81	$2,393	$25,049	$18,532	$3,205	$2,371

[a] Assumes 80 percent reduction with the implementation of quarterly IR camera monitoring.
[b] The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of $19,470 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between seven stations within a company-defined area.
[c] Annual cost for well sites includes annual monitoring and repair cost of $4,071 and amortization of the capital cost over 8 years at 7 percent interest. 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 percent interest.
[d] Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as $4 Mcf.

9.3.1.2 Fugitive Emission Detection and Correction with Method 21

Description

Another option that can be used to reduce fugitive emissions from well sites and gathering and boosting stations involves the development of a fugitive emissions monitoring plan using Method 21 to detect leaks from equipment and components. The plan would incorporate surveying of components at a specified interval and repair threshold using a Method 21 instrument, which also includes following the Method 21 requirements for monitoring, along with repair, recordkeeping and reporting requirements.

The plan would also include provisions for repair or replacement of components if evidence of fugitive emissions are discovered during the survey. The monitoring plan would include inspection of all fugitive emission components and would require repair where evidence of fugitive emissions is discovered (as soon as practicable, but generally no later than 30 calendar days after the Method 21 survey). In addition, all repairs or replacement of components would be re-surveyed immediately after repair or replacement to ensure the fugitive emissions are below the specified repair threshold.

A facility can use a company-defined area fugitive emissions monitoring plan that covers the collection of fugitive emission components at well sites and gathering and boosting stations. By using a company-defined area, owners and operators have flexibility in developing monitoring plans and determining which company-defined area can be covered under the specifications outlined in one monitoring plan, for ease of implementation and compliance.

Control Effectiveness

Potential control efficiencies for Method 21 monitoring were estimated to be 42 to 83 percent depending on repair threshold and monitoring frequency in the 2016 NSPS. The Method 21 control options included repair thresholds of 10,000 and 500 parts per million (ppm) and annual, semiannual, and quarterly monitoring frequencies. Tables 9-14 through 9-16 present the summaries of the estimated emission reductions for annual, semiannual and quarterly Method 21 monitoring for the two repair thresholds for the well site and the gathering and boosting station model plants.

Cost Impacts

Costs (2012 dollars) for preparing and implementing a fugitive emission monitoring plan for a company-defined area (i.e., field or district) were estimated using hourly estimates for each of the plan elements. The costs are based on the following assumptions:

(1) Labor cost for each of the monitoring plan elements was estimated to be $57.80 per hour.
(2) Reading of the air agency rule and instructions would take one person four hours to complete at a cost of $231.20.
(3) Development of a fugitive emission monitoring plan would take two and one half people a total of 60 hours to complete at a cost of $3,468.
(4) Initial activities planning are estimated to take two people a total of 16 hours per monitoring event. Cost for annual monitoring was estimated to be $925, semiannual monitoring was estimated to be $1,850, and quarterly monitoring was estimated to be $3,699.

Table 9-14. Summary of the Model Plant VOC Cost of Control for the Annual Method 21 Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) [a]	Capital Cost ($2012)[b]	Annual Cost ($2012/year)[c]		Cost of Control ($2012/ton)	
			Without savings	With savings [d]	Without savings	With savings [d]
10,000 ppm Repair Threshold						
Natural Gas Well Site	.645	$1,418	$2,300	$1,762	$3,568	$2,734
Oil Well Site (GOR < 300)	0.14	$1,418	$2,300	$2,179	$16,459	$15,595
Oil Well Site (GOR ≥ 300)	0.318	$1,418	$2,300	$2,031	$7,243	$6,396
Gathering and Boosting Station	4.12	$4,283	$9,803	$6,365	$2,378	$1,544
500 ppm Repair Threshold						
Natural Gas Well Site	1.043	$1,418	$2,300	1,430	$2,204	$1,371
Oil Well Site (GOR < 300)	0.226	$1,418	$2,300	$2,104	$10,169	$9,305
Oil Well Site (GOR ≥ 300)	0.514	$1,418	$2,300	$1,865	$4,475	$3,628
Gathering and Boosting Station	6.67	$4,283	$9,803	$4,239	$1,469	$635

[a] Assumes 42 percent reduction at 10,000 ppm repair threshold and 68 percent reduction at 500 ppm repair threshold with the implementation of annual Method 21 monitoring.
[b] The capital cost for oil and natural gas well sites and gathering and boosting stations includes the cost of implementing the monitoring program which includes reading the rule, developing and implementing a monitoring plan (including initial activities planning), notification of initial compliance status, and purchase of a Method 21 monitoring device.
[c] Annual cost for oil and natural gas well sites and gathering and boosting stations includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7 percent interest.
[d] Recovery credits for oil and natural gas well sites were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as $4 Mcf.

Table 9-15. Summary of the Model Plant VOC Cost of Control for the Semiannual Method 21 Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) [a]	Capital Cost ($2012)[b]	Annual Cost ($2012/year) [c]		Cost of Control ($2012/ton)	
			Without savings	With savings [d]	Without savings	With savings [d]
10,000 ppm Repair Threshold						
Natural Gas Well Site	0.837	$1,460	$3,907	$3,209	$4,667	$3,833
Oil Well Site (GOR < 300)	0.181	$1,460	$3,907	$3,750	$21,530	$20,666
Oil Well Site (GOR ≥ 300)	0.412	$1,460	$3,907	$3,558	$9,475	$8,628
Gathering and Boosting Station	5.35	$4,415	$17,292	$12,828	$3,230	$2,396
500 ppm Repair Threshold						
Natural Gas Well Site	1.152	$1,460	$3,907	$2,946	$3,392	$2,558
Oil Well Site (GOR < 300)	0.250	$1,460	$3,907	$3,691	$15,648	$14,784
Oil Well Site (GOR ≥ 300)	0.567	$1,460	$3,907	$3,426	$6,887	$6,039
Gathering and Boosting Station	7.37	$4,415	$17,292	$11,150	$2,348	$1,514

[a] Assumes 55 percent reduction at 10,000 ppm repair threshold and 75 percent reduction at 500 ppm repair threshold with the implementation of semiannual Method 21 monitoring.
[b] The capital cost for oil and natural gas well sites and gathering and boosting stations includes the cost of implementing the monitoring program, which includes reading the rule, developing and implementing a monitoring plan (including initial activities planning), notification of initial compliance status, and purchase of a Method 21 monitoring device.
[c] Annual cost for oil and natural gas well sites and gathering and boosting stations includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7 percent interest.
[d] Recovery credits for oil and natural gas well sites were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as $4 Mcf.

Table 9-16. Summary of the Model Plant VOC Cost of Control for the Quarterly Method 21 Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) [a]	Capital Cost ($2012)[b]	Annual Cost ($2012/year) [c]		Cost of Control ($2012/ton)	
			Without savings	With savings [d]	Without savings	With savings [d]
10,000 ppm Repair Threshold						
Natural Gas Well Site	1.030	$1,544	$7,121	$6,262	$6,196	$6,083
Oil Well Site (GOR < 300)	0.223	$1,544	$7,121	$6,928	$31,906	$31,042
Oil Well Site (GOR ≥ 300)	0.507	$1,544	$7,121	$6,691	$14,042	$13,195
Gathering and Boosting Station	6.58	$4,679	$32,271	$26,780	4,901	$4,067
500 ppm Repair Threshold						
Natural Gas Well Site	1.26	$1,544	$7,121	$6,070	$5,651	$4,817
Oil Well Site (GOR < 300)	0.273	$1,544	$7,121	$6,885	$26,067	$25,202
Oil Well Site (GOR ≥ 300)	0.621	$1,544	$7,121	$6,595	$11,472	$10,624
Gathering and Boosting Station	8.06	$4,679	$32,271	$25,550	$4,004	$3,170

[a] Assumes 67 percent reduction at 10,000 ppm repair threshold and 83 percent reduction at 500 ppm repair threshold with the implementation of quarterly Method 21 monitoring.
[b] The capital cost for oil and natural gas well sites includes the cost of implementing the monitoring program of $32,120 divided by an average of 22 well sites per company.
[c] Annual cost for oil and natural gas well sites and gathering and boosting stations includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7 percent interest.
[d] Recovery credits for oil and natural gas well sites were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as $4 Mcf.

(5) Notification of compliance status was estimated to take one person one hour to complete at a cost of $58 for gathering and boosting stations. For companies that own and operate well sites, the cost of the notification of compliance was estimated to be $58 per well site for each company-defined area, which is estimated to operate 22 well sites within the defined area for a total of $1,272.

(6) Cost of a Method 21 monitoring device and data collection system was estimated at $25, 300 per company ($10,800 for the M21 monitoring device and $14,500 for the data collection system).

Costs for implementing a fugitive emission monitoring plan for a company-defined area for well sites and gathering and boosting stations were estimated for each of the monitoring and repair elements. The costs are based on the following assumptions:

(1) Subsequent activities planning are estimated to take two people a total of 16 hours per monitoring event for well sites and two people a total of 24 hours for gathering and boosting stations. For well sites, this cost was divided among the total number of well sites in the company-defined area.

(2) Method 21 monitoring was estimated to take two people a total of 16 hours to survey a well production site at a cost of $925 per survey. For gathering and boosting stations, Method 21 monitoring was estimated to take 2 people a total of 8 hours to survey the station at a cost of $925 per survey.

(3) Annual repair costs for well sites were estimated to be $299 using a repair threshold of 10,000 ppm and $5,400 using a repair threshold of 500 ppm. These costs were estimated assuming that 1.18 percent of the components leak. The repair costs assume 75 percent are repaired online and 25 percent are repaired offline.

(4) Annual repair costs for gathering and boosting stations were estimated to be $3,436 using a repair threshold of 10,000 ppm and $52,900 using a repair threshold of 500 ppm. These costs were estimated assuming that 1.18 percent of the components leak. The repair costs assume 75 percent are repaired online and 25 percent are repaired offline.

(5) Cost for resurvey of components assumes 5 minutes per leak at $57.80 per hour for well sites and $2.00 per leak for gathering and boosting stations.

(6) Preparation of annual reports was estimated to take 1 person a total of 4 hours to complete at a cost of $231.

The initial setup cost or capital cost for oil and natural gas well sites was calculated by summing up the costs for reading the rule, development of fugitive emissions monitoring plan, initial activities planning, acquisition of a Method 21 monitoring device and data collection system and notification of initial compliance status. The total capital cost of these activities was estimated to be $31,196 for annual monitoring, $32,120 for semiannual monitoring, and $33,970 for quarterly monitoring. Assuming that each company owns and operates 22 well sites within a company-defined area, the capital cost per well site was estimated to be $1,460.

For gathering and boosting stations, the capital cost was assumed to be shared with other gathering and boosting stations within the company-defined area. These stations are estimated to be approximately 70 miles apart. Therefore, within a 210-mile radius of a central location, there would be an estimated seven gathering and boosting stations and the capital cost for these stations was estimated to be $29,982 for annual monitoring, $30,907 for semiannual monitoring, and $32,756 for quarterly monitoring. Assuming that there are 7 gathering and boosting stations in a company-defined area, the capital cost per station was estimated to be $4,283 for annual monitoring, $4,415 for semiannual monitoring, and $4,679 for quarterly monitoring.

For oil and natural gas well sites and gathering and boosting stations, the annual cost includes: subsequent activities planning, Method 21 survey, cost of repair of fugitive emissions found, preparation and submittal of an annual report, and the amortized capital cost over 8 years at 7 percent interest. The annual cost for annual, semiannual, and quarterly Method 21 surveying (inclusive of cost of repair of fugitive emissions found, preparation and submittal of an annual report, and amortized capital cost over 8 years at 7 percent interest) was calculated for each of the industry segments. Tables 9-14 through 9-16 present summaries of the cost of control for VOC at each of the repair thresholds (i.e., 10,000 and 500 ppm) for the three monitoring frequency options (i.e., annual, semiannual and quarterly).

9.3.2 Existing Federal, State and Local Regulations

9.3.2.1 Federal Regulations that Specifically Require Control of VOC Emissions

For each well site and compressor station (including gathering and boosting stations), the EPA has finalized NSPS requirements that will require the development of a fugitive emissions monitoring plan that includes semiannual monitoring for well sites and quarterly monitoring for compressor stations by OGI and repair of leaking fugitive emission components. Method 21 can be used as an alternative to OGI at a 500 ppm repair threshold.

9.3.2.2 State and Local Regulations that Specifically Require Control of VOC Emissions

States or local air districts may have regulations or permitting restrictions on VOC emissions that may apply to an emission source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met, and often how the source must be operated. To ensure that sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements. A summary of some of the existing state regulations and permit programs that apply to the oil and natural gas industry is provided below.

Colorado Regulation 7

The State of Colorado has regulations that require leak inspections at all well sites, compressor stations upstream of the processing plant and storage vessels. For well production facilities and compressor stations, the monitoring frequency is determined by the estimated uncontrolled actual VOC emissions leak from the highest emitting tank or, if no tanks are present, the controlled actual emissions from all permanent equipment. The monitoring frequency for fugitives at well production facilities varies depending on emissions. There is a one-time inspection (0-6 tpy VOC), annual inspections (6-12 tpy VOC), quarterly inspections (12-20 tpy VOC w/o tanks, 12-50 w/ tanks), or monthly inspections (> 20 TPY VOC w/o tanks, > 50 tpy VOC w/ tanks). Monthly AVO inspections are also required for well production facilities that do one-time, annual, and quarterly monitoring. For compressor stations, the monitoring frequency is annual (0-12 tpy VOC), quarterly (12-50 tpy VOC), or monthly (> 50 tpy VOC). A leak is defined as hydrocarbon concentration greater than 500 ppm. These regulations allow OGI inspections, Method 21 or other "[d]ivision approved instrument based monitoring device or method" to detect leaks (Colorado Department of Public Health and Environment, Air Quality Control Commission, Regulation Number 7). The first attempt to repair leaks found during monitoring must be made no later than five working days after discovery, unless parts are unavailable or the equipment requires shutdown to complete repair. If parts are unavailable, they must be ordered promptly and the repair must be made within 15 working days of receipt of the parts. If a shutdown is required, the leak must be repaired during the next scheduled shutdown.

Wyoming Chapter 8

The Wyoming Department of Environmental Quality issued regulations in June 2015 for existing (as of January 1, 2014) PAD facility (location where more than one well and/or associated production equipment are located, where some or all production equipment is shared by more than one well or where well streams from more than one well are routed through individual production trains at the same location) and single-well oil and gas production facilities or sources, and all compressor stations that are located in the Upper Green River Basin (UGRB) ozone nonattainment area[153]. The rule requires operators with fugitive emissions greater than or equal to 4 tons per year of VOC to develop and implement an LDAR protocol by January 1, 2017. Operators must monitor components (flanges, connectors (other than flanges), open-ended lines, pumps, valves, and "other" components listed in Table 2-4 of the EPA's Protocol for Equipment Leak Emissions Estimates) quarterly using a combination of Method 21, IR camera, other instrument based technologies, or AVO inspections. However, an LDAR protocol consisting of only AVO inspections does not meet the requirements of the rule. No specific repair timeframes are included in the regulation.

Utah General Approval Order

The Utah Department of Environmental Quality approved a "General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery" on June 5, 2014[154]. This General Approval Order (GAO) requires LDAR for equipment (e.g., valve, flange or other connection, pump, compressor, pressure relief device or other vent, process drain, open-ended valve, pump seal, compressor seal, and access door seal or other seal that contains or contacts a process stream with hydrocarbons) based on annual throughput of crude oil and condensate. Annual inspections are required for sources that have a projected annual throughput of crude oil and condensate combined that is greater than or equal to 10,000 barrels or for sources that do not

[153] Wyoming regulations are available at http://soswy.state.wy.us/Rules/RULES/9868.pdf.
[154] Utah regulations are available at http://www.deq.utah.gov/Permits/GAOs/docs/2014/6June/DAQE-AN149250001-14.pdf.

have a crude oil or condensate storage tank onsite, and quarterly inspections are required for sources that have a projected annual throughput of crude oil and condensate combined that is greater than or equal to 25,000 barrels. For sources performing quarterly monitoring, provisions are provided for less frequent monitoring if no leaks are found during a year of monitoring. Repairs must be made within 15 days of finding a leak. A delay of repair is allowed if replacement parts are unavailable (must order parts within 5 days of detection and repair leak within 15 days after receipt of the parts) or technically infeasible to repair without a shutdown (shutdown must occur within 6 months of finding leak or operators must demonstrate emissions from shutdown would be greater than the uncontrolled leaking component).

The monitoring can be performed using Method 21, a tunable diode laser absorption spectroscopy (TDLAS) or an IR camera. A leak is defined as a reading of 500 ppm with Method 21 analyzer or TDLAS, or visible leak with IR camera.

Ohio General Permit

The Ohio EPA approved two types of general permits in May 2014 for oil and gas well site production operations (small flares and large flares) and high volume horizontal hydraulic fracturing 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 subpart HH)[155]. Each permittee is required to develop and implement an LDAR program for ancillary equipment (pumps, compressors, pressure relief devices, connectors, valves, flanges, vents, covers, any bypass in a closed vent system, and each storage vessel) that requires monitoring using a forward looking infrared (FLIR) camera or Method 21. Leak definitions vary depending on component (most are 500 or 10,000 ppm). Quarterly monitoring is required for the first year and varies after that depending on performance. Repairs must be made within 30 days of finding a leak but if leaks cannot be repaired within that time frame, the general permit references the delay of repair provisions allowed under NSPS subpart VVa.

Ohio has also proposed a general permit for natural gas compressor stations that have the potential to leak greater than 10 tons per year of VOC. The general permit requirements for

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[155] 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.

compressor stations are similar to the LDAR requirements for oil and gas well site production operations. No emissions data were available for this LDAR program.

Pennsylvania General Permit 5 and Exemption Category No. 38

General Permit 5 is a General Plan Approval and/or General Operating Permit for midstream natural gas gathering, compression and/or processing facilities that are minor air contamination facilities[156]. Exemption Category No. 38 of the Air Quality Permit Exemption List applies to sources located at a well pad[157]. The general permit requires operators to conduct leak detection and repair programs monthly using AVO methods. Equipment to be monitored include: valves, flanges, connectors, storage vessels/storage tanks, and compressor seals. In addition, the general permit requires annual monitoring at wells and quarterly monitoring for compression and processing facilities. Operators must use a FLIR camera or approved device to detect gaseous hydrocarbons leaks. All leaks at production sites, compressor stations or processing facilities must be repaired within 15 days of finding the leak.

West Virginia Class II General Permit G70-B

General Permit G70-B is for natural gas production facilities[158]. The permit requires quarterly monitoring using AVO, Method 21 analyzers, IR cameras, or some combination. The AVO inspection shall include, but not be limited to, defects as visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. If a Method 21 analyzer is used, a leak (fugitive emissions of regulated air pollutants) is defined as no detectable emissions (less than 500 ppm). If an IR camera is used, no detectable emissions is defined as no visible leaks detected in accordance with U.S. EPA alternative IR camera work practices (40 CFR 60, subpart A). The first attempt at repair must be made within 5 calendar days of discovering the leak, and the final repair must be made within 15 calendar days of discovering the leak. No emissions data are available for this LDAR program.

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[156] Pennsylvania regulations are available at http://www.dep.state.pa.us/dep/deputate/airwaste/aq/permits/gp/GP-5_2-25-2013.pdf.
[157] Pennsylvania regulations are available at http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-96215/275-2101-003.pdf.
[158] West Virginia regulations are available at http://www.dep.wv.gov/daq/permitting/Documents/G70-B%20Final/G70-B%20General%20Permit%20Signed2.pdf.

San Joaquin Valley Air Pollution Control District Rule 4409

The San Joaquin Valley Air Pollution Control District requires the development of an operator management plan that establishes inspection, replacement, re-inspection requirements, maintenance, repair periods and replacement retrofit requirements for components at light crude oil production facilities, natural gas production facilities and natural gas processing plants[159].

For manned facilities, the District requires owners and operators to audio-visually inspect for leaks daily and, for unmanned sites, the District requires owners and operators to audio-visually inspect for leaks weekly. Additionally, the District requires owners and operators to conduct inspections for leaks quarterly using Method 21. Leaks discovered are required to be repaired within two to seven days of discovery, depending on the magnitude of the leak. An extension of up to seven days is allowed if the leak is minor. Owners and operators are also allowed to apply for written approval to change the Method 21 monitoring inspection frequency from quarterly to annually if they meet specified criteria. Components at oil production facilities and gas production facilities that exclusively handle gas/vapor or liquid with a VOC content of 10 percent by weight or less are exempt from requirements.

9.4 Recommended RACT Level of Control

We evaluated available data obtained in the development of the 2016 NSPS final rule, comments received on the draft CTG and 2015 NSPS proposed rule, and peer review comments received on the EPA's equipment leaks white paper. Based on our evaluation of this data and information about existing regulations that control VOC emissions from oil and natural gas production sites, this CTG provides RACT recommendations for the collection of fugitive emission components at well sites with an average production of greater than 15 barrel equivalents per well per day, and gathering and boosting stations. At this time, this CTG does not include a RACT recommendation for well sites with an average production of less than 15 barrel equivalents per well per day. However, we encourage air agencies to consider site-specific data from these sources in their RACT analyses.

We further recommend that RACT be the implementation of a monitoring plan that includes semiannual monitoring for well sites with a GOR greater than or equal to 300 and quarterly monitoring for gathering and boosting stations using OGI or Method 21 and repair of

[159] San Joaquin Valley APCD regulations available at http://www.arb.ca.gov/drdb/sju/cur.htm.

components found to be leaking. The information currently available to EPA does not support applying the RACT recommendations related to fugitive monitoring contained in this chapter of the CTG to well sites with a GOR less than 300.

As discussed in section 9.3.2.2 of this chapter, some existing state and local regulations already require fugitive emissions monitoring of oil and natural gas production sites. The monitoring techniques listed in these requirements include the use of either Method 21 or OGI to locate fugitive emissions from equipment and components. In addition, peer review comments received on the equipment leaks white paper indicate that some companies are voluntarily monitoring their production sites using OGI to eliminate leaks from equipment. Monitoring and repair of equipment and components using OGI or Method 21 are the most viable methods for reducing fugitive emissions from equipment leaks in the production segment of the oil and natural gas industry.

Both Wyoming and Ohio require quarterly monitoring of components at production sites, and the cost of control per ton of VOC reduced is considered reasonable for OGI quarterly monitoring for natural gas well sites (about $3,450 per ton of VOC reduced). However, based on the information currently available regarding the necessary equipment, trained personnel and the planning necessary to implement a monitoring and repair program, we are concerned about the potential compliance burden that could be associated with quarterly monitoring of the large number of existing well sites. The VOC cost of control for semiannual monitoring using OGI was estimated to be $2,494 per ton of VOC reduced for natural gas well sites and $5,062 per ton of VOC reduced for oil wells sites with a GOR greater than or equal to 300.

We do not estimate that there would be a compliance burden associated with quarterly fugitive OGI monitoring at gathering and boosting stations because there are fewer existing gathering and boosting stations than well sites. Moreover, the cost of control per ton of VOC reduced is reasonable for quarterly OGI monitoring. The VOC cost of control for quarterly monitoring using OGI was estimated to be about $3,200 per ton of VOC reduced for gathering and boosting stations.

For well sites, the cost of control for a monitoring plan using Method 21 with a 10,000 ppm leak detection is generally more costly than the use of OGI where there are a large number of equipment components to be monitored. The cost for a natural gas well site was estimated to be $4,667 per ton of VOC reduced for semiannual monitoring. The cost for an oil well site with a

GOR greater than 300 was estimated to be $9,475 per ton of VOC reduced for semiannual monitoring. As shown in section 9.3.1 of this chapter, the cost of control for the 500 ppm repair threshold options are higher than the 10,000 ppm repair threshold option. The use of a monitoring plan using Method 21 with a 10,000 ppm leak detection may, however, be a lower cost alternative to OGI where there are fewer equipment components to be monitored. For gathering and boosting stations, the cost of control for a monitoring plan using Method 21 with a 10,000 ppm leak detection is estimated to be $3,230 per ton of VOC reduced for semiannual monitoring and $3,205 for quarterly monitoring. The costs for semiannual monitoring using Method 21 for natural gas well sites, and quarterly monitoring using Method 21 for gathering and boosting stations were considered reasonable (about $4,670 for gas well sites and $3,200 for gathering and boosting stations). Based on our analyses that indicates that a monitoring plan using Method 21 at 500 ppm would meet the same level of control as semiannual monitoring using OGI, we recommend that air agencies allow owners and operators to comply by using Method 21 at 500 ppm as an alternative to semiannual monitoring using OGI.

Based on existing state and local fugitive emission requirements, economic feasibility, and the reasonableness of costs, we recommend that RACT for the collection of fugitive emission components at well sites with a GOR greater than or equal to 300 that produce, on average, greater than 15 barrel equivalents per well per day, be the implementation of a fugitive emissions monitoring and repair plan that includes semiannual monitoring using OGI or Method 21. For these same reasons, we recommend that RACT for the collection of fugitive emission components at gathering and boosting stations be the implementation of a fugitive emissions monitoring and repair plan that includes quarterly monitoring using OGI or Method 21.

In summary, we recommend the following RACT for the collection of fugitive emission components at well sites and gathering and boosting stations in the production segment:

(1) <u>RACT for the Collection of Fugitive Emission Components at Well Sites With a GOR Greater than or Equal to 300, that Produce, on Average, Greater than 15 Barrel Equivalents per Well per Day</u>: We recommend the implementation of a monitoring plan that includes semiannual monitoring using OGI and repair of components that are found to be leaking at well sites. We further recommend that air agencies allow Method 21 with a repair threshold of 500 ppm as an alternative compliance means to OGI. We also

recommend that each fugitive emissions component repaired or replaced be resurveyed to ensure there is no leak after repair or replacement by the use of either Method 21 or OGI no later than 30 days of finding fugitive emissions.

(2) RACT for the Collection of Fugitive Emission Components at Gathering and Boosting Stations in the Production Segment (Located from the Wellhead to the Point of Custody Transfer to the Natural Gas Transmission and Storage Segment or Oil Pipeline): We recommend the implementation of a monitoring plan that includes quarterly monitoring using OGI and repair of components that are found to be leaking at gathering and boosting stations. We further recommend allowing Method 21 with a repair threshold of 500 ppm as an alternative to OGI. We also recommend that each fugitive emissions component repaired or replaced be resurveyed to ensure there is no leak after repair or replacement by the use of either Method 21 or OGI no later than 30 days of finding fugitive emissions.

9.5 Factors to Consider in Developing Fugitive Emissions RACT Procedures

To ensure that fugitive emissions are properly monitored and repaired (as necessary) under the RACT recommendations, we suggest that air agencies specify OGI/Method 21 monitoring and equipment repair recordkeeping and reporting requirements to document compliance. The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

9.5.1 Monitoring Recommendations

We recommend that air agencies require a fugitive emissions OGI/Method 21 monitoring plan that covers fugitive emission component sources that includes basic required monitoring plan elements. We recommend that air agencies require the monitoring plan be developed for a company-defined area and that it cover the collection of fugitive emissions components at well sites and gathering and boosting stations.

We suggest that the fugitive emissions monitoring plan that covers the collection of fugitive emissions components at well sites and gathering and boosting stations within each company-defined area include the following minimum elements:

(1) Frequency for conducting surveys.

(2) Technique for determining fugitive emissions.

(3) Manufacturer and model number of fugitive emissions detection equipment to be used.

(4) Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair.

(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.

(7) If you are using OGI, you should also include the following: (i) Verification that your optical gas imaging equipment meets specification requirements (i.e., capable of imaging gases in a spectral range for the compound of highest concentration in the potential fugitive emissions, must be capable of imaging a gas that is half methane and half propane at a concentration of 10,000 ppm at a flow rate of less than or equal to 60 g/hr from a quarter inch diameter); (ii) Procedure for a daily verification check; (iii) Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained; (iv) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold; (v) Procedures for conducting surveys; (vi) Training and experience needed prior to performing surveys; including how the operator will (a) ensure an adequate thermal background is present in order to view potential fugitive emissions, (b) deal with adverse monitoring conditions such as wind, (c) deal with interferences; and (vii) Procedures for calibration and maintenance.

(8) Procedures for calibration and maintenance should comply with those recommended by the manufacturer of monitoring device used.

(9) If you are using Method 21 of appendix A-7 of part 60, you should also include the following: (i) Verification that your monitoring equipment meets the requirements specified in section 6.0 of Method 21 at 40 CFR part 60, appendix A-7; and (ii) procedures for conducting surveys.

We suggest that you also require the following minimum elements in each fugitive emissions monitoring plan:

(1) Sitemap.

(2) A defined observation path that ensures that all fugitive emissions components are within sight of the path. The observation path must account for interferences.

(3) If you are using Method 21, the plan should also include a list of fugitive emission components to be monitored and method for determining location of fugitive emission components to be monitored in the field (e.g., tagging, identification on a process and instrumentation diagram, etc.).

(4) Your plan should also include the written plan developed for all of the fugitive emission components designated as difficult-to-monitor and unsafe-to-monitor.

We recommend a monitoring survey of each collection of fugitive emissions components at a well site be conducted semiannually after the initial survey and that consecutive semiannual monitoring surveys be conducted at least four months apart. We recommend a monitoring survey of each collection of fugitive emissions components at a gathering and boosting station be conducted quarterly after the initial survey and that consecutive quarterly monitoring surveys be conducted at least two months apart.

9.5.2 Repair Recommendations

We recommend that air agencies require that any identified source of fugitive emissions identified by using OGI (indicated by visual emissions) or Method 21 instrument (indicated by a concentration of 500 ppm above background) be repaired or replaced as soon as practicable, but no later than 30 calendar days after detection of the fugitive emissions. If the repair or replacement is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next compressor station shutdown, well shutdown, well shut-in, after an unscheduled, planned or emergency vent blowdown or within 2 years, whichever is earlier. We also recommend that repaired or replaced fugitive emission components be required to be resurveyed as soon as practicable, but no later than 30 days after completion of the repair or replacement, to ensure that there is no leak. For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, we recommend that air agencies require that the operator resurvey the repaired fugitive emissions components using Method 21 (or alternative screening procedure based on soap bubble solution method (as specified under section 8.3.3 of Method 21)), or OGI no later than 30 days of being repaired. A fugitive emissions component is repaired when either the Method 21 instrument indicates a concentration of less than 500 ppm above background, or an OGI instrument shows no indication of visible emissions.

Appendix

We include model rule language in this appendix for our recommended RACT for oil and natural gas industry sources. The intent of this language is to provide regulation language that states can use as a starting point in the development of their SIP. In some cases, the language may need to be revised to make it adequate for SIP approval purposes. Although we include model rule language for closed vent systems, control devices and performance tests (that apply across several model rule requirements for sources), it is acknowledged that states may have existing similar language in their programs that they may want to use in lieu of the model language provided. State implementation plans should specify enforceable test methods.

The model rule language does not specify rule compliance dates. These dates will be determined by air agencies (referred to within the model rule language as the “regulatory authority”). State and local government agencies are encouraged to search this model rule language for places where the “regulatory authority” will need to specify dates (e.g., compliance date) by searching for (“regulatory authority”) in the model rule language.

Appendix: Table of Contents

A Storage Vessels: VOC Emission Control Requirements

A.1 Applicability

(a) The VOC emissions control requirements of section A apply to each storage vessel located in the oil and natural gas industry (excluding distribution) that has the potential for VOC emissions equal to or greater than 6 tpy. The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline established by your regulatory authority. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a federal, state, local or tribal authority. Any vapor from the storage vessel that is recovered and routed to a process through a VRU designed and operated as specified in this section is not required to be included in the determination of VOC potential to emit for purposes of determining applicability, provided you comply with the requirements in section A.1(a)(i) through (a)(iv).

(i) You meet the cover requirements specified in section A.2(c).

(ii) You meet the closed vent system requirements specified in section A.2(d).

(iii) You must maintain records that document compliance with paragraphs A.2(c) and (d).

(iv) In the event of removal of apparatus that recovers and routes vapor to a process, or operation that is inconsistent with the conditions specified in paragraphs A.2(c) and (d) of this section, you must determine the storage vessel's potential for VOC emissions according to this section within 30 days of such removal or operation.

(b) A storage vessel with a capacity greater than 100,000 gallons used to recycle water that has been passed through two stage separation is not a storage vessel.

(c) The storage vessel VOC emission control requirements specified in this section do not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, 40 CFR part 63, subparts G, CC, HH, or WW.

A.2 What VOC Emission Control Requirements Apply to Storage Vessels?

For each storage vessel, you must comply with the VOC emission control requirements of paragraphs (a) through (e) in this section by the compliance date established by your regulatory authority. Alternative requirements for storage vessels subject to VOC emission control requirements that meet certain conditions are presented in paragraph (i) of this section. Requirements for storage vessels removed from service are presented in paragraph (j) of this section.

(a) You must reduce VOC emissions from each storage vessel by 95.0 percent, unless you meet the conditions of paragraph (i) of this section.

(b) (1) Except as required in paragraph (b)(2) of this section, if you use a control device to reduce emissions, you must equip the storage vessel with a cover that meets the requirements of paragraph (c) of this section, that is connected through a closed vent system that meets the requirements of paragraph (d) of this section and route to a control device that meets the conditions specified in paragraph (e) of this section, as applicable. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(2) If you use a floating roof to reduce emissions, you must meet the requirements of 40 CFR 60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb.

(c) *Cover requirements for storage vessels.* (1) The cover and all openings on the cover (*e.g.,* access hatches, sampling ports, pressure relief valves and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel.

(2) Each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed vent system, designed and operated in accordance with the requirements of paragraph (d) of this section to a control device or to a process.

(3) Each storage vessel thief hatch shall be equipped, maintained and operated with a weight, or other mechanism, to ensure that the lid remains properly seated and sealed under normal operating conditions, including such times when working, standing/breathing, and flash emissions may be generated. You must select gasket material for the hatch based on composition of the fluid in the storage vessel and weather conditions.

(d) *Closed vent system requirements for storage vessels*. For closed vent system requirements using a control device or routing emissions to a process, you must comply with the following:

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the storage vessel to a control device or to a process that meets the requirements specified in paragraph (e) of this section, or to a process.

(2) You must design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual and auditory inspections.

(3) You must meet the requirements specified in paragraph (d)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process.

(i) Except as provided in paragraph (d)(3)(ii) of this section, you must comply with either paragraph (d)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away for the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to section A.5(a)(9).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (d)(3)(i) of this section.

(4) You must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all emissions from the storage vessel are routed to the control device or to a process and that the control device is of sufficient design and capacity to accommodate all emissions from the storage vessel and have it certified by a qualified professional engineer in accordance with paragraphs (d)(4)(i) and (ii) of this section.

(i) You must provide the following certification, signed and dated by the qualified professional engineer: "I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted and this report was prepared pursuant to the requirements of this rule. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information."

(ii) The assessment shall be prepared under the direction or supervision of the qualified professional engineer who signs the certification in paragraph (d)(4)(i) of this section.

(e) *Control device requirements for storage vessels*.

(1) Each control device used to meet the emission reduction standard in paragraph (a) of this section for your storage vessel must be installed according to paragraphs (e)(1)(i) through (iv) of this section, as applicable. As an alternative to paragraph (e)(1)(i) of this section, you may install a control device model tested under section F(d), which meets the criteria in section F(d)(11) and meets the continuous compliance requirements in section F(e).

(i) For each enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) you must follow the requirements in paragraphs (e)(1)(i)(A) through (D) of this section.

(A) Ensure that each enclosed combustion device is maintained in a leak free condition.

(B) Install and operate a continuous burning pilot flame.

(C) Operate the enclosed combustion device with no visible emissions, except for periods not to exceed a total of one minute during any 15 minute period. A visible emissions test using section 11 of EPA Method 22, 40 CFR part 60, appendix A-7, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes. Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection. Following return to operation from maintenance or repair activity, each device must pass a Method 22, 40 CFR part 60, appendix A-7, visual observation as described in this paragraph.

(D) Each enclosed combustion control device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (*1*) through (*4*) of this section.

(*1*) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of section F(b).

(*2*) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the applicable requirements of section F(b).

(*3*) You must operate at a minimum temperature of 760°Celsius, provided the control device has demonstrated, during the performance test conducted under section F(b), that combustion zone temperature is an indicator of destruction efficiency.

(*4*) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(ii) Each vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater. A carbon replacement schedule must be included in the design of the carbon adsorption system.

(iii) You must design and operate a flare in accordance with the requirements of 40 CFR 60.18(b), and you must conduct the compliance determination using Method 22, 40 CFR part 60, appendix A-7, to determine visible emissions.

(iv) You must operate each control device used to comply with paragraph (a) of this section at all times when gases, vapors, and fumes are vented from the storage vessel through the closed vent system to the control device. You may vent more than one storage vessel to a control device used to comply with this subpart.

(2) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (e)(2)(i) and (ii) of this section.

(i) Following the initial startup of the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to section F(c)(2) or (3) or according to the design required in paragraph (e)(1)(ii) of this section, for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement as required in section A.5(a)(10).

(ii) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (e)(2)(ii)(A) through (F) of this section.

(A) Regenerate or reactivate the spent carbon in a thermal treatment unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(B) Regenerate or reactivate the spent carbon in a unit equipped with operating organic air emission controls in accordance with an emissions standard for VOC under a subpart in 40 CFR part 60 or part 63.

(C) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(D) Burn the spent carbon in a hazardous waste boiler or industrial furnace for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(E) Burn the spent carbon in an industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(F) Burn the spent carbon in an industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

(f) You must demonstrate initial compliance with the VOC emission reduction requirements that apply to each storage vessel as required in section A.3.

(g) You must demonstrate continuous compliance with the VOC emission control requirements that apply to each storage vessel as required by section A.4.

(h) You must perform the required recordkeeping and reporting as required by section A.5.

(i) *Alternative requirements for storage vessels*. Maintain the uncontrolled actual VOC emissions from the storage vessel subject to VOC emission control requirements at less than 4 tpy without considering control. Prior to using the uncontrolled actual VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology. Monthly calculations must be based on the average throughput for the month. Monthly calculations must be separated by at least 14 days. You must comply with paragraph (i)(1) or (2) of this section.

(1) If a well feeding the storage vessel subject to VOC emission control requirements undergoes fracturing or refracturing, you must comply with paragraph (a) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel.

(2) If the monthly emissions determination required in this paragraph indicates that VOC emissions from your storage vessel subject to VOC emission control requirements increases to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel, you must comply with paragraph (a) of this section within 30 days of the monthly calculation.

(j) *Requirements for storage vessels that are removed from service or returned to service.* If you are the owner or operator of a storage vessel subject to the VOC emission control requirements that is removed from service, you must comply with paragraphs (j)(1) and (2) of this section. A storage vessel is not an affected source under this section for the period that it is removed from service.

(1) For a storage vessel to be removed from service, you must comply with the requirements of paragraph (j)(1)(i) and (ii) of this section.

(i) You must completely empty and degas the storage vessel, such that the storage vessel no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(ii) You must submit a notification in your next annual report, identifying each storage vessel removed from service during the reporting period and the date of its removal from service.

(2) If a storage vessel subject to VOC emission control requirements identified in paragraph (j)(1) of this section is returned to service during the reporting year, you must submit a notification in your next annual report identifying each storage vessel that has been returned to service and the date of its return to service.

A.3 Initial Compliance Demonstration Requirements

You must demonstrate initial compliance with the VOC emission control requirements for each storage vessel complying with section A.2 by complying with the requirements in paragraphs (a) through (h) of this section.

(a) You determine the potential VOC emission rate as specified in section A.1(a).

(b) You reduce VOC emissions from each storage vessel subject to VOC emission control requirements by 95.0 percent or greater as required in section A.2 and as demonstrated by section F.

(c) If you use a control device to reduce emissions, you must equip your storage vessel with a cover that meets the requirements of section A.2(c) that is connected through a closed vent system that meets the requirements of section A.2(d) and is routed to a control device that meets the requirements of A.2(e). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(d) You conduct an initial performance test as required in section F within 180 days after the compliance date established by your regulatory authority.

(e) You conduct the initial cover and closed vent system inspections according to the requirements in section A.4(d) within 180 days after the compliance date established by your regulatory authority.

(f) You submit the initial annual report for your storage vessels as required in section A.5(b).

(g) You maintain the records as specified in section A.5(a).

(h) If you comply by using a floating roof, you submit a statement that you are complying with 40 CFR 60.112b(a)(1) or (2) in accordance with section A.2(b)(2) with the initial annual report specified in section A.5(b).

A.4 Continuous Compliance Demonstration Requirements

You have demonstrated continuous compliance for each storage vessel subject to the VOC emission control requirements in section A.2 by meeting the requirements in paragraphs (a) through (f) of this section.

(a) For each storage vessel subject to VOC emission reduction requirements, you must demonstrate continuous compliance according to paragraphs (b) and (c) of this section.

(b) You must reduce VOC emissions from the storage vessel by 95.0 percent or greater.

(c) For each control device used to reduce emissions, you must demonstrate continuous compliance with the performance requirements of section A.2(e) according to paragraphs (c)(1) through (4) of this section. You are exempt from the requirements of this paragraph if you install a control device model tested in accordance with sections F(d)(2) through (10), which meets the criteria in section F(d)(11), the reporting requirements in section F(d)(12), and the continuous compliance requirements in F(e).

(1) For each combustion device you must conduct inspections at least once every calendar month according to paragraphs (c)(1)(i) through (iv) of this section. Monthly inspections must be separated by at least 14 calendar days.

(i) Conduct visual inspections to confirm that the pilot is lit when vapors are being routed to the combustion device and that the continuous burning pilot flame is operating properly.

(ii) Conduct inspections to monitor for visible emissions from the combustion device using section 11 of EPA Method 22, 40 CFR part 60, appendix A-7. The observation period shall be 15 minutes. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period.

(iii) Conduct olfactory, visual and auditory inspections of all equipment associated with the combustion device to ensure system integrity.

(iv) For any absence of pilot flame, or other indication of smoking or improper equipment operation (*e.g.*, visual, audible, or olfactory), you must ensure the equipment is returned to proper operation as soon as practicable after the event occurs. At a minimum, you must perform the procedures specified in paragraphs (c)(1)(iv)(A) and (B) of this section.

(A) You must check the air vent for obstruction. If an obstruction is observed, you must clear the obstruction as soon as practicable.

(B) You must check for liquid reaching the combustor.

(2) For each vapor recovery device, you must conduct inspections at least once every calendar month to ensure physical integrity of the control device according to the manufacturer's instructions. Monthly inspections must be separated by at least 14 calendar days.

(3) Each control device must be operated following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices

for minimizing emissions. Records of the manufacturer's written operating instructions, procedures, and maintenance schedule must be available for inspection as specified by A.5(a)(11).

(4) Conduct a periodic performance test no later than 60 months after the initial performance test as specified in section F(b)(5)(ii) and conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test.

(d) If you install a control device or route emissions to a process, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (d)(1) of this section, inspect each cover according to the procedures and schedule specified in paragraph (d)(2) of this section, and inspect each bypass device according to the procedures of paragraph (d)(3) of this section. You must also comply with the requirements of (d)(4) through (7) of this section.

(1) For each closed vent system, you must conduct an inspection at least once every calendar month as specified in paragraphs (d)(1)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in section A.5(a)(7).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(2) For each cover, you must conduct inspections at least once every calendar month as specified in paragraphs (d)(2)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in section A.5(a)(8).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (*e.g.,* fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(3) For each bypass device, except as provided for in section A.2(d)(3)(ii), you must meet the requirements of paragraphs (d)(3)(i) or (ii) of this section.

(i) You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible alarm, or initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is sounded according to section A.5(a)(9).

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections and records of each time the key is checked out, if applicable, according to section A.5(a)(9).

(4) *Repairs*. In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (d)(4)(i) through (iii) of this section, except as provided in paragraph (d)(5) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 30 calendar days after the leak is detected.

(iii) Grease or another applicable substance must be applied to deteriorating or cracked gaskets to improve the seal while awaiting repair.

(5) *Delay of repair*. Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(6) *Unsafe to inspect requirements*. You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (d)(6)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (d)(1) and (2) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (d)(1) or (2) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(7) *Difficult to inspect requirements*. You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (d)(7)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (d)(1) and (2) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(e) You must submit the annual reports for your storage vessels as required in section A.5(b).

(f) You must maintain the records as specified in section A.5(a).

A.5 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements.* For each storage vessel, you must maintain the records identified in paragraphs (a)(1) through (12) of this section, as applicable, either onsite or at the nearest local field office for at least five years.

(1) If required to reduce emissions by complying with section A.2(a), the records specified in paragraphs (a)(6) through (8) of this section and sections A.4(d)(6)(ii) and A.4(d)(7)(ii), as applicable.

(2) Records of each VOC emissions determination for each storage vessel made under A.1(a) including identification of the model or calculation methodology used to calculate the VOC emission rate.

(3) Records of deviations in cases where the storage vessel was not operated in compliance with the requirements specified in sections A.2 and F, as applicable.

(4) For storage vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), records indicating the number of consecutive days that the vessel is located at a site in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment. If a storage vessel is removed from a site and, within 30 days, is either returned to or replaced by another storage vessel at the site to serve the same or similar function, then the entire period since the original storage vessel was first located at the site, including the days when the storage vessel was removed, must be added to the count towards the number of consecutive days.

(5) Records of the identification and location of each storage vessel subject to emission control requirements.

(6) Except as specified in paragraph (a)(6)(vii) of this section, you must maintain the records specified in paragraphs (a)(6)(i) through (vi) of this section for each control device tested under section F(d) which meets the criteria in section F(d)(11) and meets the continuous

compliance requirements in section F(d) (e) and used to comply with section A.2(a) for each storage vessel.

(i) Make, model and serial number of purchased device.

(ii) Date of purchase.

(iii) Copy of purchase order.

(iv) Location of the control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(v) Inlet gas flow rate.

(vi) Records of continuous compliance requirements in section F(e) as specified in paragraphs (a)(6)(vi)(A) through (E).

(A) Records that the pilot flame is present at all times of operation.

(B) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15 minute period.

(C) Records of the maintenance and repair log.

(D) Records of the visible emissions test following return to operation from a maintenance or repair activity.

(E) Records of the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(vii) As an alternative to the requirements of paragraph (a)(6)(iv) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the storage vessel and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the storage vessel and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(7) Records of each closed vent system inspection required under section A.4(d)(1)(i).

(8) A record of each cover inspection required under section A.4(d)(2)(i).

(9) If you are subject to the bypass requirements of section A.4(d)(3), a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

(10) For each carbon adsorber installed on a storage vessel, records of the schedule for carbon replacement (as determined by the design analysis requirements of section E.1(a)(2)) and records of each carbon replacement as specified in section E.1(c)(1).

(11) For each storage vessel subject to the control device requirements of section E.2(c) and (d), records of the inspections, including any corrective actions taken, the manufacturers' operating instructions, procedures and maintenance schedule as specified in section E.2(h). Records of section 11, EPA Method 22, 40 CFR part 60, appendix A-7 results, which include: company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22-1 in EPA Method 22, 40 CFR part 60, appendix A-7. Control device manufacturer operating instructions, procedures and maintenance schedule must be available for inspection.

(12) A log of records as specified in sections A.2(e)(1)(i)(C) and F(e)(4), for all inspection, repair and maintenance activities for each control device failing the visible emissions test.

(b) *Reporting requirements*. For storage vessels, you must submit annual reports containing the information specified in paragraphs (b)(1) through (6) of this section.

(1) An identification, including the location, of each storage vessel subject to VOC emission control requirements. The location of the storage vessel shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(2) Documentation of the VOC emission rate determination according to section A.1(a).

(3) Records of deviations specified in paragraph (a)(3) of this section that occurred during the reporting period.

(4) A statement that you have met the requirements specified in section A.3(b) and (c).

(5) You must identify each storage vessel that is removed from service during the reporting period as specified in section A.2(j)(1), including the date the storage vessel was removed from service.

(6) You must identify each storage vessel returned to service during the reporting period as specified in section A.2(j)(3), including the date the storage vessel was returned to service.

A.6 Definitions

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including, but not limited to, general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.*, a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions. Completion combustion devices include pit flares.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Hydraulic fracturing means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

Hydraulic refracturing means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

Maximum average daily throughput means the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods.

Natural gas liquids means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

Pressure vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Produced water means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

Qualified professional engineer means an individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge and experience to make the specific technical certifications required under this subpart. Professional engineers making these certifications must be currently licensed in at least one state in which the certifying official is located.

Removed from service means that a storage vessel subject to the VOC control requirements has been physically isolated and disconnected from the process for a purpose other than maintenance.

Returned to service means that a storage vessel subject to the VOC requirements that was removed from service has been:

(1) Reconnected to the original source of liquids or has been used to replace any storage vessel subject to the VOC requirements; or

(2) Installed in any location covered by this rule and introduced with crude oil, condensate, intermediate hydrocarbon liquids or produced water.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process that is operational where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered for beneficial use.

Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of section A.2(j)(1) until such time as such tank or other vessel has been returned to service. For the purposes of this rule, the following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by section A.5(a)(4), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site.

(2) Process vessels such as surge control vessels, bottoms receivers or knockout vessels.

(3) Pressure vessels designed to operate in excess of 204.9 kilopascals (29.7 pounds per square inch) and without emissions to the atmosphere.

B Pneumatic Controllers: VOC Emission Control Requirements

B.1 Applicability

The VOC emission control requirements specified in section B.2 apply to the pneumatic controllers specified in paragraphs (a) and (b) of this section.

(a) For natural gas processing plants, each pneumatic controller, which is a single continuous bleed natural gas-driven pneumatic controller.

(b) At locations from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline, each pneumatic controller, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 standard cubic feet per hour.

B.2 What VOC Emission Control Requirements Apply to Pneumatic Controllers?

For each pneumatic controller, you must comply with requirements for VOC, as specified in either paragraph (b)(1) or (c)(1) of this section, as applicable. Pneumatic controllers meeting the conditions in paragraph (a) of this section are exempt from these requirements.

(a) The requirements of paragraph (b)(1) or (c)(1) of this section are not required if you determine that the use of a pneumatic controller with a bleed rate greater than the applicable standard is required based on functional needs including, but not limited to, response time, safety and positive actuation. However, you must tag such pneumatic controller with the date that the pneumatic controller is required to comply with the model rule (as established by your regulatory authority) and identification information that allows traceability to the records for that pneumatic controller, as required in section B.5(a)(2).

(b)(1) Each pneumatic controller subject to VOC emissions control requirements at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller subject to VOC emissions control requirements at a natural gas processing plant, as defined in section B.1(a), must be tagged with the date that the pneumatic controller is required to comply with the model rule (as established by your regulatory authority) and identification information that allows traceability to the records for that pneumatic controller as required in section B.5(a)(3).

(c)(1) Each pneumatic controller subject to VOC emissions control requirements at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller subject to VOC emission control requirements at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline, as defined in section B.1(b), must be tagged with the date that the pneumatic controller is required to comply with the model rule (as established by your regulatory authority) that allows traceability to the records for that controller as required in section B.5(a).

(d) You must demonstrate initial compliance by the compliance date established by your regulatory authority by demonstrating compliance with the VOC emission reduction requirements that apply to pneumatic controllers as required by section B.3.

(e) You must demonstrate continuous compliance with VOC emission reduction requirements that apply to pneumatic controllers as required by section B.4.

(f) You must perform the required recordkeeping as required by B.5(a) and reporting as required by section B.5(b).

B.3 Initial Compliance Demonstration Requirements

You must demonstrate initial compliance with the VOC emission control requirements for your pneumatic controller by complying with the requirements specified in paragraphs (a) through (f) of this section by the compliance date established by your regulatory authority, as applicable.

(a) You must demonstrate initial compliance by maintaining records as specified in section B.5(a)(2) of your determination that the use of a pneumatic controller with a bleed rate greater than the applicable standard is required as specified in section B.2(a).

(b) You own or operate a pneumatic controller located at a natural gas processing plant and your pneumatic controller is a non-natural gas-driven pneumatic controller that emits zero natural gas and VOC.

(c) You own or operate a pneumatic controller located between the wellhead and a natural gas processing plant and the manufacturer's design specifications indicate that the controller emits less than or equal to 6 standard cubic feet of gas per hour.

(d) You must tag each pneumatic controller according to the requirements of section B.2(b)(2) or (c)(2).

(e) You must include the information in paragraph (a) of this section and a listing of the pneumatic controller sources specified in paragraphs (b) and (c) of this section in the initial annual report according to the requirements of section B.5(b)

(f) You must maintain the records as specified in section B.5(a) for each pneumatic controller subject to VOC emission control requirements.

B.4 Continuous Compliance Demonstration Requirements

For each pneumatic controller, you must demonstrate continuous compliance according to paragraphs (a) through (c) of this section.

(a) You must continuously operate each pneumatic controller as required in section B.2(a), (b), or (c).

(b) You must submit the annual reports as required in section B.5(b).

(c) You must maintain records as required in section B.5(a).

B.5 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements*. For each pneumatic controller, you must maintain the records identified in paragraphs (a)(1) through (4) of this section onsite or at the nearest local field office for at least five years.

(1) Records of the date, location and manufacturer specifications for each pneumatic controller.

(2) If applicable, a record of the demonstration that the use of a pneumatic controller with a natural gas bleed rate greater than the applicable standard is required and the reasons why.

(3) If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.

(4) Records of deviations in cases where the pneumatic controller was not operated in compliance with the requirements specified in section B.2.

(b) *Reporting requirements*. You must submit annual reports containing the information specified in paragraphs (b)(1) through (3) of this section.

(1) An identification of each existing pneumatic controller, including the identification information specified in section B.2(b)(2) or (c)(2).

(2) If applicable, documentation that the use of a pneumatic controller with a natural gas bleed rate greater than the applicable standard is required and the reasons why.

(3) Records of deviations specified in paragraph (a)(4) of this section that occurred during the reporting period.

B.6 Definitions

Bleed rate means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a pneumatic controller.

Continuous bleed means a continuous flow of pneumatic supply natural gas to a pneumatic controller.

Custody transfer means the transfer of natural gas after processing and/or treatment in the producing operations or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Flow line means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

Natural gas-driven pneumatic controller means a pneumatic controller powered by pressurized natural gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Non-natural gas-driven pneumatic controller means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Pressure vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Underground storage vessel means a storage vessel stored below ground

Wellhead means 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. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

C Compressors: VOC Emissions Control Requirements

C.1 Applicability

(a) *Centrifugal compressors*. Each centrifugal compressor, which is a single centrifugal compressor using wet seals located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not a source subject to VOC requirements under this rule.

(b) *Reciprocating compressors*. Each reciprocating compressor located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not a source subject to VOC requirements under this rule.

C.2 What VOC Emission Control Requirements Apply to Centrifugal Compressors?

For each centrifugal compressor, you must comply with the VOC emissions control requirements in paragraphs (a) through (g).

(a) You must reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent.

(b) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of section D.1(a)(1). The cover must be connected through a closed vent system that meets the requirements of section D.1(b) and the closed vent system must be routed to a control device that meets the conditions specified in paragraph (d) of this section. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(c) For each control device used to comply with the VOC emission reduction control requirements in paragraph (a), you must install and operate a continuous parameter monitoring system for each control device as specified in section E.2(a) through (f), except as provided for in section E.2(b).

(d) You must operate each control device installed on your centrifugal compressor in accordance with the requirements specified in paragraphs (d)(1) and (2) of this section.

(1) You must operate each control device used to comply with this rule at all times when gases, vapors, and fumes are vented from the wet seal fluid degassing system through the closed vent system to the control device. You may vent more than one source to a single control device.

(2) For each control device monitored in accordance with the requirements of section E.2(a) through (f), you must demonstrate continuous compliance according to the requirements of section C.5(a)(2), as applicable.

(e) You must demonstrate initial compliance with the VOC emission reduction requirements that apply to each centrifugal compressor as required by section C.4(a).

(f) You must demonstrate continuous compliance with the VOC emission control requirements that apply to each centrifugal compressor as required by section C.5(a).

(g) You must perform the required recordkeeping and reporting as required by section C.6(a)(1) and (b)(1), as applicable.

C.3 What VOC Emission Control Requirements Apply to Reciprocating Compressors?

You must comply with the VOC emission control requirements in paragraphs (a) through (d) of this section for each reciprocating compressor.

(a) You must replace the reciprocating compressor rod packing according to either paragraph (a)(1) or (2) of this section or you must comply with paragraph (a)(3) of this section.

(1) On or before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning on the compliance date for your

reciprocating compressor as established by your regulatory authority, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the compliance date for a reciprocating compressor for which the rod packing has not yet been replaced.

(3) Route VOC emissions to a process by using a rod packing emissions collection system that operates under negative pressure and meets the cover requirements of section D.1(a)(2) and the closed vent system requirements of section D.1.(b).

(b) You must demonstrate initial compliance with requirements that apply to reciprocating compressor sources as required by section C.4(b).

(c) You must demonstrate continuous compliance with requirements that apply to reciprocating compressor sources as required by section C.5(b).

(d) You must perform the required recordkeeping and reporting as required by section C.6(a)(2) and (b)(2).

C.4 Initial Compliance Demonstration Requirements

You must demonstrate initial compliance with the VOC emission control requirements for each centrifugal compressor by complying with the requirements in paragraph (a) of this section, and for each reciprocating compressor by complying with the requirements in paragraph (b) of this section.

(a) *Centrifugal compressors*. You have achieved initial compliance with the VOC emission control requirements for each centrifugal compressor if you have complied with paragraphs (a)(1) through (7) of this section.

(1) You reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater as required in section C.2(a) and as demonstrated by section F.

(2) You use a control device to reduce emissions, and you equip the wet seal fluid degassing system with a cover that meet the requirements of section D.1(a) that is connected through a closed vent system that meets the requirements of section D.1(b) and is routed to a control device that meets the requirements of section E.1. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(3) You conduct an initial performance test as required in section F within 180 days after the compliance date established by your regulatory authority.

(4) You conduct the initial cover and closed vent system inspections required in section D.2 within 180 days after the compliance date established by your regulatory authority.

(5) You install and operate the continuous parameter monitoring systems in accordance with section E.2(a) through (g).

(6) You submit the initial annual report for your centrifugal compressor as required in section C.6(b)(1).

(7) You maintain the records as specified in section C.6(a)(1).

(b) *Reciprocating compressors*. You have achieved initial compliance with the VOC emission control requirements for each reciprocating compressor if you have complied with paragraphs (b)(1) through (4) of this section.

(1) If complying with section C.3(a)(1) and (2), you must continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement, beginning on the compliance date established by your regulatory authority.

(2) If complying with section C.3(a)(3), you must route VOC emissions to a process by using a rod packing emissions collection system that operates under negative pressure and meets the cover requirements of section D.1(a)(2) and the closed vent system requirements of section D.1.(b) by the compliance date established by your regulatory authority.

(3) You must submit the initial annual report for your reciprocating compressor as required in section C.6(b)(2).

(4) You maintain the records as specified in section C.6(a)(2).

C.5 Continuous Compliance Demonstration Requirements

You have demonstrated continuous compliance for each centrifugal compressor by complying with the requirements of paragraph (a), and for each reciprocating compressor by complying with the requirements of paragraph (b).

(a) *Centrifugal compressors*. For each centrifugal compressor subject to VOC emission reduction requirements, you must demonstrate continuous compliance according to paragraphs (a)(1) through (4) of this section.

(1) You must reduce VOC emissions from the wet seal fluid degassing system by 95.0 percent or greater.

(2) For each control device used to reduce emissions, you must demonstrate continuous compliance with the performance requirements of section C.2(a) using the procedures specified in paragraphs (a)(2)(i) through (vii) of this section. If you use a condenser as the control device to achieve the requirements specified in section C.2(a), you may demonstrate compliance according to paragraph (a)(2)(viii) of this section. You may switch between compliance with paragraphs (a)(2)(i) through (vii) of this section and compliance with paragraph (a)(2)(viii) of this section only after at least 1 year of operation in compliance with the selected approach. You must provide notification of such a change in the compliance method in the next annual report, following the change.

(i) You must operate below (or above) the site specific maximum (or minimum) parameter value established according to the requirements of section E.2(f)(1).

(ii) You must calculate the daily average of the applicable monitored parameter in accordance with section E.2(e) except that the inlet gas flow rate to the control device must not be averaged.

(iii) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (a)(2)(ii) of this section is either equal to or greater than the minimum monitoring value or equal to or less than the maximum monitoring value established under paragraph (a)(2)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in section F(d), compliance with the operating parameter limit is achieved when the criteria in section F(e) are met.

(iv) You must operate the continuous monitoring system required in section E.2(a) at all times the source is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments). A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(v) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other required data collection periods to assess the operation of the control device and associated control system.

(vi) Failure to collect required data is a deviation of the monitoring requirements, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments).

(vii) If you use a combustion control device to meet the requirements of section C.2(a) and you demonstrate compliance using the test procedures specified in section F(b), or you use a flare designed and operated in accordance with 40 CFR 60.18(b), you must comply with paragraphs (a)(2)(vii)(A) through (D) of this section.

(A) A pilot flame must be present at all times of operation.

(B) Devices must be operated with no visible emissions, except for periods not to exceed a total of one minute during any 15-minute period. A visible emissions test using section 11 of Method 22, 40 CFR part 60, appendix A-7, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(C) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(D) Following return to operation from maintenance or repair activity, each device must pass a Method 22, 40 CFR part 60, appendix A-7, visual observation as described in paragraph (a)(2)(vii)(B) of this section.

(viii) If you use a condenser as the control device to achieve the percent reduction performance requirements specified in section C.2(a)(1), you must demonstrate compliance using the procedures in paragraphs (a)(2)(viii)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to section E.2(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with section E.2(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (a)(2)(viii)(B) of this section and the condenser performance curve established under paragraph (a)(2)(viii)(A) of this section.

(D) You must calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (a)(2)(viii)(C) of this section.

(1) If you have less than 120 days of data for determining average TOC emission reduction, you must calculate the average TOC emission reduction for the first 120 days of operation. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the 120-day average TOC emission reduction is equal to or greater than 95.0 percent.

(2) After 120 days and no more than 364 days of operation, you must calculate the average TOC emission reduction as the TOC emission reduction averaged over the number of days of operation where you have data. You have demonstrated compliance with the overall 95.0 percent reduction requirement, if the average TOC emission reduction is equal to or greater than 95.0 percent.

(E) If you have data for 365 days or more of operation, you have demonstrated compliance with the TOC emission reduction if the rolling 365-day average TOC emission reduction calculated in paragraph (a)(2)(viii)(D) of this section is equal to or greater than 95.0 percent.

(3) You must submit the annual reports required by section C.6(b)(1) and maintain the records as specified in section C.6(a)(1).

(4) If you comply with this rule by equipping the wet seal fluid degassing system and route emissions to a control device or process as required by section C.2(b), you must comply with the cover and closed vent requirements in section D.1(a) and (b).

(b) *Reciprocating compressors*. For each reciprocating compressor subject to VOC emission reduction requirements, you must demonstrate continuous compliance according to paragraphs (b)(1) through (4) of this section.

(1) You must continuously monitor the number of hours of operation for each reciprocating compressor or track the number of months or the date of the most recent reciprocating compressor rod packing replacement.

(2) You must submit the annual reports as required in section C.6(b)(2) and maintain records as required in section C.6(a)(2).

(3) You must replace the reciprocating compressor rod packing on or before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

(4) If you comply with this rule by collecting and routing VOC emissions from the rod packing using a rod packing emissions collection system which operates under negative pressure as required by section C.3(a)(3), you must operate the rod packing emissions collection system under negative pressure and continuously comply with the closed vent system requirements in section D.1(b).

C.6 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements*.

(1) *Centrifugal compressors*. For each centrifugal compressor, you must maintain records of the information specified in paragraphs (a)(1)(i) and (ii) of this section, and, if required to comply with section C.2(a), the records specified in paragraphs (a)(1)(iii) through (ix) of this section. These records must be maintained onsite or at the nearest local field office for at least five years.

(i) An identification of each existing centrifugal compressor using a wet seal system.

(ii) Records of deviations where the centrifugal compressor was not operated in compliance with requirements specified in section C.2. Except as specified in paragraph (a)(1)(ii)(G) of this section, you must maintain the records in paragraphs (a)(1)(ii)(A) through (F) of this section for each control device tested under section F(d) which meets the criteria in section F(d)(11) and meets continuous compliance requirements in section F(e) and used to comply with section C.2(a) for each centrifugal compressor.

(A) Make, model and serial number of purchased device.

(B) Date of purchase.

(C) Copy of purchase order.

(D) Location of the centrifugal compressor and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(E) Inlet gas flow rate.

(F) Records of continuous compliance requirements in section F(e) as specified in paragraphs (a)(1)(ii)(F)(*1*) through (*5*) of this section.

(*1*) Records that the pilot flame is present at all times of operation.

(*2*) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15 minute period.

(*3*) Records of the maintenance and repair log.

(*4*) Records of the visible emissions test following return to operation from a maintenance or repair activity.

(*5*) Records of the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(G) As an alternative to the requirements of paragraph (a)(1)(ii)(D) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the centrifugal compressor and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the centrifugal compressor and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(iii) Records of each closed vent system inspection required under section D.2(a) and (b).

(iv) A record of each cover inspection required under section D.2(c).

(v) If you are subject to the bypass requirements of section D.2(d), a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

(vi) If you are subject to the closed vent system no detectable emissions requirements of section D.2(a) and (b), a record of the monitoring in accordance with section D.2(e).

(vii) For each centrifugal compressor, records of the schedule for carbon replacement (as determined by the design analysis requirements of section F(c)(2) or (3)) and records of each carbon replacement as specified in section E.1(c)(1).

(viii) For each centrifugal compressor subject to the control device requirements of section E.1, records of minimum and maximum operating parameter values, continuous parameter monitoring system data, calculated averages of continuous parameter monitoring system data, results of all compliance calculations, and results of all inspections.

(ix) A log of records for all inspection, repair and maintenance activities for each control device failing the visible emissions test as specified in section C.5(a)(2)(vii)(C).

(2) *Reciprocating compressors*. For each reciprocating compressor VOC emissions source, you must maintain the records in paragraphs (a)(2)(i) through (iv) of this section. These records must be maintained onsite or at the nearest local field office for at least five years.

(i) Records of the cumulative number of hours of operation or number of months since the previous replacement of the reciprocating compressor rod packing. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

(ii) Records of the date and time of each reciprocating compressor rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system as specified in section C.3(a)(3).

(iii) Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in section C.3.

(iv) If you comply by routing emissions from the rod packing to a process through a closed vent system under negative pressure. You must maintain the records in paragraphs (a)(2)(iv)(A) through (D) of this section.

(A) Records of each closed vent system inspection required under section D.2(a) and (b).

(B) If you are subject to the bypass requirements of section D.2(d), a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

(C) If you are subject to the closed vent system no detectable emissions requirements of section D.2(a) and (b), a record of the monitoring in accordance with section D.2(e).

(D) A record of each cover inspection required under section D.2(c).

(b) *Reporting requirements*.

(1) *Centrifugal compressors*. For each centrifugal compressor, you must submit annual reports containing the information specified in paragraphs (b)(1)(i) through (iv) of this section.

(i) An identification of each existing centrifugal compressor using a wet seal system.

(ii) Records of deviations specified in paragraph (a)(1)(ii) of this section that occurred during the reporting period.

(iii) If required to comply with section C.2(a), the records specified in paragraphs (a)(1)(iii) through (viii) of this section.

(iv) If complying with C.2(a) with a control device tested under section F(d) which meets the criteria in section F(d)(11) and meets the continuous compliance requirements in section F(e), in the initial annual report, records specified in paragraphs (a)(1)(ii)(A) through (a)(1)(ii)(G) of this section for each centrifugal compressor using a wet seal system that is subject to this rule. In subsequent annual reports, records specified in paragraph (a)(1)(ii)(F) of this section along with information sufficient to link to the identifying information provided in the initial report.

(2) *Reciprocating compressors*. For each reciprocating compressor, you must submit annual reports containing the information specified in paragraphs (b)(2)(i) through (iii) of this section.

(i) The cumulative number of hours of operation or the number of months since the compliance date, or since the previous reciprocating compressor rod packing replacement, whichever is later. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

(ii) Records of deviations specified in paragraph (a)(2)(iii) of this section that occurred during the reporting period.

(iii) If required to comply with section C.3(a)(3), the records specified in paragraphs (a)(2)(i) through (iv) of this section.

C.7 Definitions

Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low-pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this rule.

Collection system means any infrastructure that conveys gas or liquids from the well site to another location for treatment, storage, processing, recycling, disposal or other handling.

Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations. The combination of one or more compressors located at a well site, or located at an onshore natural gas processing plant, is not a compressor station for purposes of this rule.

Custody transfer means the transfer of natural gas after processing and/or treatment in the producing operations or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Flow line means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere, or other mechanism that provides the same function.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Wellhead means 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. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well.

D Cover and Closed Vent System Requirements

[Note: These requirements would not apply to covers and closed vent systems used on storage vessels.]

D.1 What Are My Cover and Closed Vent System Requirements?

You must meet the applicable requirements of this section for each cover and closed vent system where VOC emissions are routed to a control device or to a process.

(a) *Cover requirements*.

(1) Centrifugal compressor cover requirements.

(i) The cover and all openings on the cover shall form a continuous impermeable barrier over the entire surface area of the liquid in the wet seal fluid degassing system.

(ii) Each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) except during those times when it is necessary to use an opening as follows:

(A) To inspect, maintain, repair, or replace equipment; or

(B) To vent gases or fumes from the unit through a closed vent system designed and operated in accordance with the requirements of paragraph (b) of this section to a control device or to a process.

(2) Reciprocating compressor cover requirements.

(i) The cover and all openings on the cover shall form a continuous impermeable barrier over the rod packing emissions collection system.

(ii) Each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) except during those times when it is necessary to use an opening as follows:

(A) To inspect, maintain, repair, or replace equipment; or

(B) To vent gases or fumes from the unit through a closed vent system designed and operated in accordance with the requirements of paragraph (b) of this section to a process.

(b) *Closed vent system requirements*.

(1) (i) Centrifugal compressors. You must design the closed vent system to route all gases, vapors, and fumes emitted from the VOC emissions source to a control device or to a process. For centrifugal compressors, the closed vent system must route all gases, vapors, and fumes to a control device that meets the requirements specified in section E.1(a) through (c).

(ii) Reciprocating compressors. You must design the closed vent system to route all gases, vapors, and fumes emitted from the VOC emissions source to a process.

(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by section D.2(e).

(3) You must meet the requirements specified in paragraph (b)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or process.

(i) Except as provided in paragraph (b)(3)(ii) of this section, you must comply with either paragraph (b)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings as specified in section D.2(d)(1) and sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away for the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to section C.6(a)(1)(v) for centrifugal compressors, C.6(a)(2)(iv)(B) for reciprocating compressors or H.5(a)(2)(ii) for pneumatic pumps, as applicable.

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (b)(3)(i) of this section.

(4) You must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all emissions from the emission source are routed to the control device and that the control device is of sufficient design and capacity to accommodate all emissions from the emission source and have it certified by a qualified professional engineer in accordance with paragraphs (b)(4)(i) and (ii) of this section.

(i) You must provide the following certification, signed and dated by the qualified professional engineer: "I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted and this report was prepared pursuant to the requirements of this rule. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information."

(ii) The assessment shall be prepared under the direction or supervision of the qualified professional engineer who signs the certification in paragraph (b)(4)(i) of this section.

D.2 What Are My Initial and Continuous Cover and Closed Vent System Inspection and Monitoring Requirements?

Except as provided in paragraphs (e)(11) and (12) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a) and (b) of this section, inspect each cover according to the procedures and schedule specified in paragraph (c) of this section, and inspect each bypass device according to the procedures of paragraph (d) of this section.

(a) For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (*e.g.*, a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), you must meet the requirements specified in paragraphs (a)(1) and (2) of this section.

(1) Conduct an initial inspection according to the test methods and procedures specified in paragraph (e) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results according to section C.6(a)(1)(vi) for centrifugal compressors, C.6(a)(2)(iv)(C) for reciprocating compressors or H.5(a)(2)(iii) for pneumatic pumps, as applicable.

(2) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must monitor a component or connection using the test methods and procedures in paragraph (e) of this section to demonstrate that it operates with no detectable emissions following any time the component is repaired or the connection is unsealed. You must maintain records of the inspection results according to section C.6(a)(1)(vi) for centrifugal compressors, C.6(a)(2)(iv)(C) for reciprocating compressors or H.5(a)(2)(iii) for pneumatic pumps, as applicable.

(b) For closed vent system components other than those specified in paragraph (a) of this section, you must meet the requirements of paragraphs (b)(1) through (3) of this section.

(1) Conduct an initial inspection according to the test methods and procedures specified in paragraph (e) of this section to demonstrate that the closed vent system operates with no detectable emissions by the date established by your regulatory authority. You must maintain records of the inspection results according to section C.6(a)(1)(vi) for centrifugal compressors, C.6(a)(2)(iv)(C) for reciprocating compressors or H.5(a)(2)(iii) for pneumatic pumps, as applicable.

(2) Conduct annual inspections according to the test methods and procedures specified in paragraph (e) of this section to demonstrate that the components or connections operate with no detectable emissions. You must maintain records of the inspection results according to section C.6(a)(1)(vi) for centrifugal compressors, C.6(a)(2)(iv)(C) for reciprocating compressors or H.5(a)(2)(iii) for pneumatic pumps, as applicable.

(3) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose

connections; liquid leaks; or broken or missing caps or other closure devices. You must maintain records of the inspection results according to according to section C.6(a)(1)(vi) for centrifugal compressors, or H.5(a)(2)(i) for pneumatic pumps, as applicable.

(c) For each cover, you must meet the requirements in paragraphs (c)(1) and (2) of this section.

(1) Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices.

(2) You must initially conduct the inspections specified in paragraph (c)(1) of this section following the installation of the cover. Thereafter, you must perform the inspection at least once every calendar year, except as provided in paragraphs (e)(11) and (12) of this section. For centrifugal compressors, you must maintain records of the inspection results according to section C.6(a)(1)(iv). For reciprocating compressors, you must maintain records of the inspection results according to C.6(a)(2)(iv)(D).

(d) For each bypass device, except as provided for in section D.1(b)(3)(ii), you must meet the requirements of paragraphs (d)(1) or (2) of this section.

(1) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the stream away from the control device to the atmosphere.

(2) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections according to section C.6(a)(1)(v) for centrifugal compressors, C.6(a)(2)(iv)(B) for reciprocating compressors or H.5(a)(2)(ii) for pneumatic pumps, as applicable.

(e) *No detectable emissions test methods and procedures.* If you are required to conduct an inspection of a closed vent system or cover as specified in paragraphs (a), (b), or (c) of this section, you must meet the requirements of paragraphs (e)(1) through (13) of this section.

(1) You must conduct the no detectable emissions test procedure in accordance with Method 21, 40 CFR part 60, appendix A-7.

(2) The detection instrument must meet the performance criteria of Method 21, 40 CFR part 60, appendix A-7, except that the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the fluid and not for each individual organic compound in the stream.

(3) You must calibrate the detection instrument before use on each day of its use by the procedures specified in EPA Method 21, 40 CFR part 60, appendix A-7.

(4) Calibration gases must be as specified in paragraphs (e)(4)(i) and (ii) of this section.

(i) Zero air (less than 10 parts per million by volume hydrocarbon in air).

(ii) A mixture of methane in air at a concentration less than 10,000 parts per million by volume.

(5) You may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If you choose to adjust the instrument readings for the background level, you must determine the background level value according to the procedures in EPA Method 21, 40 CFR part 60, appendix A-7.

(6) Your detection instrument must meet the performance criteria specified in paragraphs (e)(6)(i) and (ii) of this section.

(i) Except as provided in paragraph (e)(6)(ii) of this section, the detection instrument must meet the performance criteria of EPA Method 21, 40 CFR part 60, appendix A-7, except the instrument response factor criteria in section 8.1.1 of EPA Method 21 must be for the average composition of the process fluid, not each individual volatile organic compound in the stream.

For process streams that contain nitrogen, air, or other inerts that are not volatile organic compounds, you must calculate the average stream response factor on an inert-free basis.

(ii) If no instrument is available that will meet the performance criteria specified in paragraph (e)(6)(i) of this section, you may adjust the instrument readings by multiplying by the average response factor of the process fluid, calculated on an inert-free basis, as described in paragraph (e)(6)(i) of this section.

(7) You must determine if a potential leak interface operates with no detectable emissions using the applicable procedure specified in paragraph (e)(7)(i) or (ii) of this section.

(i) If you choose not to adjust the detection instrument readings for the background organic concentration level, then you must directly compare the maximum organic concentration value measured by the detection instrument to the applicable value for the potential leak interface as specified in paragraph (e)(8) of this section.

(ii) If you choose to adjust the detection instrument readings for the background organic concentration level, you must compare the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (e)(5) of this section with the applicable value for the potential leak interface as specified in paragraph (e)(8) of this section.

(8) A potential leak interface is determined to operate with no detectable organic emissions if the organic concentration value determined in paragraph (e)(7) of this section is less than 500 parts per million by volume.

(9) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (e)(9)(i) and (ii) of this section, except as provided in paragraph (e)(10) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 15 calendar days after the leak is detected.

(10) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(11) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (e)(11)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (a) through (c) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a), (b), or (c) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(12) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (e)(12)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (a) through (c) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(13) *Records.* Records shall be maintained as specified in this section and in sections that reference this section.

E VOC Emission Control Device Requirements

[These requirements do not apply to control devices used on storage vessels.]

E.1 Initial Control Device Compliance Requirements

You must meet the applicable requirements of this section for each control device used to comply with VOC emission reduction requirements.

(a) Each control device used to meet the VOC emission reduction requirements must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative, you may install a control device model tested under section F(d), which meets the criteria in section F(d)(11) and the continuous compliance requirements in section F(e).

(1) Each combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iv) of this section.

(i) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of section F(b), with the exceptions noted in section F(a).

(ii) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the applicable requirements of section F(b), with the exceptions noted in section F(a).

(iii) You must operate at a minimum temperature of 760° Celsius for a control device, provided the control device has demonstrated, during the performance test conducted under section F(b), that combustion zone temperature is an indicator of destruction efficiency.

(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(2) Each vapor recovery device (e.g., carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of section F(b). As an alternative to the performance testing requirements, you may demonstrate initial compliance by conducting a design analysis for vapor recovery devices according to the requirements of section F(c).

(3) You must design and operate a flare in accordance with the requirements of 40 CFR 60.18(b), and you must conduct the compliance determination using EPA Method 22 of 40 CFR part 60, appendix A-7, to determine visible emissions.

(b) You must operate each control device installed to control VOC emissions from your emissions source in accordance with the requirements specified in paragraphs (b)(1) and (2) of this section.

(1) You must operate each control device used to comply with this rule at all times when gases, vapors, and fumes are vented from your VOC emissions source through the closed vent system to the control device. You may vent more than one source to a control device used to comply with this rule.

(2) For each control device monitored in accordance with the requirements of section E.2(a) through (g), you must demonstrate continuous compliance according to the requirements of section C.5(a)(2) for centrifugal compressors, as applicable.

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (c)(1) and (2) of this section.

(1) Following the compliance date established by your regulatory authority for the source using the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to section F(c)(2) or (3) or according to the design required in paragraph (a)(2) of this

section, for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement.

(2) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (c)(2)(i) through (vi) of this section.

(i) Regenerate or reactivate the spent carbon in a thermal treatment unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(ii) Regenerate or reactivate the spent carbon in a unit equipped with operating organic air emission controls in accordance with an emissions standard for VOC under a subpart in 40 CFR part 60 or part 63.

(iii) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(iv) Burn the spent carbon in a hazardous waste boiler or industrial furnace for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(v) Burn the spent carbon in an industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(vi) Burn the spent carbon in an industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

E.2 Continuous Control Device Monitoring Requirements

You must meet the applicable requirements of this section to demonstrate continuous compliance for each control device used to meet VOC emission control requirements.

(a) For each control device used to comply with the VOC emission reduction requirements, you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with section E.1(a)(3), you are exempt from the requirements of paragraphs (e) and (f) of this section.

(b) You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.

(1) A boiler or process heater in which all vent streams are introduced with the primary fuel, or used as the primary fuel.

(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(c) If you are required to install a continuous parameter monitoring system, you must meet the specifications and requirements in paragraphs (c)(1) through (4) of this section.

(1) Each continuous parameter monitoring system must measure data values at least once every hour and record the parameters in paragraphs (c)(1)(i) or (ii) of this section.

(i) Each measured data value.

(ii) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(2) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (c)(2)(i) through (v) of this section. You must install, calibrate, operate, and maintain each continuous parameter monitoring system in accordance with the procedures in your approved site-specific monitoring plan. Heat sensing monitoring devices that indicate the

continuous ignition of a pilot flame are exempt from the calibration, quality assurance and quality control requirements in this section.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(ii) Sampling interface (e.g., thermocouple) location such that the monitoring system will provide representative measurements.

(iii) Equipment performance checks, system accuracy audits, or other audit procedures.

(iv) Ongoing operation and maintenance procedures in accordance with provisions in 40 CFR 60.13(b).

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in 40 CFR 60.7(c), (d), and (f).

(3) You must conduct the continuous parameter monitoring system equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(4) You must conduct a performance evaluation of each continuous parameter monitoring system in accordance with the site-specific monitoring plan. Heat sensing monitoring devices that indicate the continuous ignition of a pilot flame are exempt from the calibration, quality assurance and quality control requirements in this section.

(d) You must install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in either paragraph (d)(1), (2), or (3) of this section.

(1) A continuous monitoring system that measures the operating parameters in paragraphs (d)(1)(i) through (viii) of this section, as applicable.

(i) For a thermal vapor incinerator that demonstrates during the performance test conducted under section F(b) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(ii) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device must be capable of monitoring temperature at two locations and have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater. You must install one temperature sensor in the vent stream at the nearest feasible point to the catalyst bed inlet, and you must install a second temperature sensor in the vent stream at the nearest feasible point to the catalyst bed outlet.

(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame. The heat sensing monitoring device is exempt from the calibration requirements of this section.

(iv) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(v) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater. You must install the temperature sensor at a location in the exhaust vent stream from the condenser.

(vi) For a regenerative-type carbon adsorption system, a continuous monitoring system that meets the specifications in paragraphs (d)(1)(vi)(A) and (B) of this section.

(A) The continuous parameter monitoring system must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow continuous parameter monitoring system is not equipped with a redundant flow sensor; and

(B) The continuous parameter monitoring system must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater.

(vii) For a non-regenerative-type carbon adsorption system, you must monitor the design carbon replacement interval established using a design analysis performed as specified in section F(c)(3). The design carbon replacement interval must be based on the total carbon working capacity of the control device and source operating schedule.

(viii) For a combustion control device whose model is tested under section F(d), a continuous monitoring system meeting the requirements of paragraphs (d)(1)(viii)(A) and (B) of this section. If you comply with the periodic testing requirements of F(b)(5)(ii), you are not required to continuously monitor the gas flow rate under paragraph (d)(1)(viii)(A).

(A) The continuous monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ±2 percent or better at the maximum expected flow rate. The flow rate at the inlet to the combustion device must not exceed the maximum or minimum flow rate determined by the manufacturer.

(B) A monitoring device that continuously indicates the presence of the pilot flame while emissions are routed to the control device.

(2) An organic monitoring device equipped with a continuous recorder that measures the concentration level of organic compounds in the exhaust vent stream from the control device. The monitor must meet the requirements of Performance Specification 8 or 9 of 40 CFR part 60, appendix B. You must install, calibrate, and maintain the monitor according to the manufacturer's specifications.

(e) You must calculate the daily average value for each monitored operating parameter for each operating day, using the data recorded by the monitoring system, except for inlet gas flow rate and data from the heat sensing devices that indicate the presence of a pilot flame. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(f) For each operating parameter monitor installed in accordance with the requirements of paragraph (d) of this section, you must comply with paragraph (f)(1) of this section for all control devices. When condensers are installed, you must also comply with paragraph (f)(2) of this section.

(1) You must establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of section E.1(a)(1) or (2). You must establish each minimum or maximum operating parameter value as specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) If you conduct performance tests in accordance with the requirements of section F(b) to demonstrate that the control device achieves the applicable performance requirements specified in section E.1(a)(1) or (2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer recommendations or a combination of both.

(ii) If you use a condenser design analysis in accordance with the requirements of section F(c) to demonstrate that the control device achieves the applicable performance requirements specified in section E.1(a)(2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on the condenser design analysis and supplemented, as necessary, by the condenser manufacturer's recommendations.

(iii) If you operate a control device where the performance test requirement was met under section F(d) to demonstrate that the control device achieves the applicable performance requirements specified in section E.1(a)(1), then your control device inlet gas flow rate must not exceed the maximum or minimum inlet gas flow rate determined by the manufacturer.

(2) If you use a condenser as specified in paragraph (d)(1)(v) of this section, you must establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency, according to the requirements of paragraphs (f)(2)(i) and (ii) of this section.

(i) If you conduct a performance test in accordance with the requirements of section F(b) to demonstrate that the condenser achieves the applicable performance requirements in section E.1(a)(2), then the condenser performance curve must be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(ii) If you use a control device design analysis in accordance with the requirements of section F(c)(1) to demonstrate that the condenser achieves the applicable performance requirements specified in section E.1(a)(2), then the condenser performance curve must be based on the condenser design analysis and supplemented, as necessary, by the control device manufacturer's recommendations.

(g) A deviation for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (g)(1) through (6) of this section being met. If you monitor multiple operating parameters for the same control device during the same operating day and more than one of these operating parameters meets a deviation criterion specified in paragraphs (g)(1) through (6) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section or when the heat sensing device indicates that there is no pilot flame present.

(2) If you meet section E.1(a)(2), a deviation occurs when the 365-day average condenser efficiency calculated according to the requirements specified in section C.5(a)(2)(viii)(D) is less than 95.0 percent.

(3) If you meet section E.1(a)(2) and you have less than 365 days of data, a deviation occurs when the average condenser efficiency calculated according to the procedures specified in section C.5(a)(2)(viii)(D)(*1*) or (*2*) is less than 95.0 percent.

(4) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(5) If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, a deviation occurs when the requirements of paragraphs (g)(5)(i) or (ii) of this section are met.

(i) For each bypass line subject to section D.1(b)(3)(i)(A), the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(ii) For each bypass line subject to section D.1(b)(3)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(6) For a combustion control device whose model is tested under section F(d), a deviation occurs when the conditions of paragraphs (g)(6)(i) or (ii) are met.

(i) The inlet gas flow rate exceeds the maximum established during the test conducted under section F(d).

(ii) Failure of the monthly visible emissions test conducted under section F(e)(3) occurs.

F Performance Test Procedures

This section applies to the performance testing of control devices used to demonstrate compliance with your VOC emission control requirements. You must demonstrate that a control device achieves the performance requirements specified for your centrifugal compressor using the performance test methods and procedures specified in this section. For condensers and carbon adsorbers, you may use a design analysis as specified in paragraph (c) of this section in lieu of complying with paragraph (b) of this section. In addition, this section contains the requirements for enclosed combustion device performance tests conducted by the manufacturer, as relevant and allowed for compliance demonstration purposes.

(a) *Performance test exemptions.* You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (7) of this section.

(1) *A flare that is designed and operated in accordance with 40 CFR 60.18(b).* You must conduct the compliance determination using EPA Method 22, 40 CFR part 60, appendix A-7, to determine visible emissions.

(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.

(4) A boiler or process heater burning hazardous waste for which you have either been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, subpart H; you have certified compliance with the interim status requirements of 40 CFR part 266, subpart H; you have submitted a Notification of Compliance under 40 CFR 63.1207(j) and comply with the requirements of 40 CFR part 63, subpart EEE; or you comply with 40 CFR part 63, subpart EEE and will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in the rule for submitting the initial performance test report.

(5) A hazardous waste incinerator for which you have submitted a Notification of Compliance under 40 CFR 63.1207(j), or for which you will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in the rule for submitting the initial performance test report, and you comply with the requirements of 40 CFR part 63, subpart EEE.

(6) A performance test is waived in accordance with 40 CFR 60.8(b).

(7) A control device whose model can be demonstrated to meet the performance requirements of section E.1(a) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b) *Test methods and procedures.* You must use the test methods and procedures specified in paragraphs (b)(1) through (5) of this section, as applicable, for each performance test conducted to demonstrate that a control device meets the requirements of section E.1(a) or A.2(e)(1). You must conduct the initial and periodic performance tests according to the schedule specified in paragraph (b)(5) of this section. Each performance test must consist of a minimum of 3 test runs. Each run must be at least 1 hour long.

(1) You must use EPA Method 1 or 1A, 40 CFR part 60, appendix A-1, as appropriate, to select the sampling sites specified in paragraphs (b)(1)(i) and (ii) of this section. Any references to particulate mentioned in EPA Methods 1 and 1A do not apply to this section.

(i) Sampling sites must be located at the inlet of the first control device and at the outlet of the final control device, to determine compliance with the control device percent reduction requirement.

(ii) The sampling site must be located at the outlet of the combustion device to determine compliance with the enclosed combustion device TOC exhaust gas concentration limit.

(2) You must determine the gas volumetric flowrate using EPA Method 2, 2A, 2C, or 2D, 40 CFR part 60, appendix A-2, as appropriate.

(3) To determine compliance with the control device percent reduction performance requirement in section E.1(a)(1)(i) or (a)(2), or section A.2(e)(1)(i)(D)(*1*) or (e)(1)(ii), you must

use EPA Method 25A at 40 CFR part 60, appendix A-7. You must use EPA Method 4 at 40 CFR part 60, appendix A-3 to convert the EPA Method 25A results to a dry basis. You must use the procedures in paragraphs (b)(3)(i) through (iii) of this section to calculate percent reduction efficiency.

(i) You must compute the mass rate of TOC using the following equations:

$$E_i = K_2 C_i M_p Q_i$$

$$E_o = K_2 C_o M_p Q_o$$

Where:

E_i, E_o = Mass rate of TOC at the inlet and outlet of the control device, respectively, dry basis, kilograms per hour.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20°Celsius.

C_i, C_o = Concentration of TOC, as propane, of the gas stream as measured by EPA Method 25A at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

M_p = Molecular weight of propane, 44.1 gram/gram-mole.

Q_i, Q_o = Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

(ii) You must calculate the percent reduction in TOC as follows:

$$R_{cd} = \frac{E_i - E_o}{E_i} * 100\%$$

Where:

R_{cd} = Control efficiency of control device, percent.

$E_{i,}$ = Mass rate of TOC at the inlet to the control device as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

E_o = Mass rate of TOC at the outlet of the control device, as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

(iii) If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC across the device by comparing the TOC in all combusted vent streams and primary and secondary fuels with the TOC exiting the device, respectively.

(4) You must use EPA Method 25A, 40 CFR part 60, appendix A-7 to measure TOC, as propane, to determine compliance with the TOC exhaust gas concentration limit specified in section E.1(a)(1)(ii) or section A.2(e)(1)(i)(D)(*2*). You may also use EPA Method 18, 40 CFR part 60, appendix A-6 to measure methane and ethane. You may subtract the measured concentration of methane and ethane from the EPA Method 25A measurement to demonstrate compliance with the concentration limit. You must determine the concentration in parts per million by volume on a wet basis and correct it to 3 percent oxygen, using the procedures in paragraphs (b)(4)(i) through (iii) of this section.

(i) If you use EPA Method 18 to determine methane and ethane, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run. You must determine the average methane and ethane concentration per run. The samples must be taken during the same time as the EPA Method 25A sample.

(ii) You may subtract the concentration of methane and ethane from the EPA Method 25A TOC, as propane, concentration for each run.

(iii) You must correct the TOC concentration (minus methane and ethane, if applicable) to 3 percent oxygen as specified in paragraphs (b)(4)(iii)(A) and (B) of this section.

(A) You must use the emission rate correction factor for excess air, integrated sampling and analysis procedures of EPA Method 3A or 3B, 40 CFR 60, appendix A-2, ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17) to determine the oxygen concentration. The samples must be taken during the same time that the samples are taken for determining TOC concentration.

(B) You must correct the TOC concentration for percent oxygen as follows:

$$C_c = C_m\left(\frac{17.9}{20.9 - \%O_{2m}}\right)$$

Where:

C_c = TOC concentration, as propane, corrected to 3 percent oxygen, parts per million by volume on a wet basis.

C_m = TOC concentration, as propane, (minus methane and ethane, if applicable), parts per million by volume on a wet basis.

$\%O_{2m}$ = Concentration of oxygen, percent by volume as measured, wet.

(5) You must conduct performance tests according to the schedule specified in paragraphs (b)(5)(i) and (ii) of this section.

(i) You must conduct an initial performance test within 180 days after the compliance date for your source as established by your regulatory authority.

(ii) You must conduct periodic performance tests for all control devices required to conduct initial performance tests except as specified in paragraphs (b)(5)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(5)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit.

(A) A control device whose model is tested under, and meets the criteria of paragraph (d) of this section. For centrifugal compressors, if you do not continuously monitor the gas flow rate in accordance with section E.2(d)(1)(viii), then you must comply with the periodic performance testing requirements of paragraph (b)(5)(ii).

(B) A combustion control device tested under paragraph (b) of this section that meets the outlet TOC performance level specified in section E.1(a)(1)(ii) and that establishes a correlation between firebox or combustion chamber temperature and the TOC performance level. For centrifugal compressors, you must establish a limit on temperature in accordance with section E.2(f) and continuously monitor the temperature as required by section E.2(d).

(c) *Control device design analysis to meet the requirements of section E.1(a).* (1) For a condenser, the design analysis must include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and must establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream and the design average temperatures of the coolant fluid at the condenser inlet and outlet.

(2) For a regenerable carbon adsorption system, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, adsorption cycle time, number and capacity of carbon beds, type and working capacity of activated carbon used for the carbon beds, design total regeneration stream flow over the period of each complete carbon bed regeneration cycle, design carbon bed temperature after regeneration, design carbon bed regeneration time, and design service life of the carbon.

(3) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon

used for the carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems will incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(4) If you and the regulatory authority do not agree on a demonstration of control device performance using a design analysis, then you must perform a performance test in accordance with the requirements of paragraph (b) of this section to resolve the disagreement. The regulatory authority may choose to have an authorized representative observe the performance test.

(d) *Performance testing for combustion control devices—manufacturers' performance test.* (1) This paragraph applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer must demonstrate that a specific model of control device achieves the performance requirements in paragraph (d)(11) of this section by conducting a performance test as specified in paragraphs (d)(2) through (10) of this section. You must submit a test report for each combustion control device in accordance with the requirements in paragraph (d)(12) of this section.

(2) Performance testing must consist of three one-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. Propene (propylene) gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90-100 percent of maximum design rate (fixed rate).

(ii) 70-100-70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30-70-30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0-30-0 percent (ramp up, ramp down). Begin the test at the minimum firing rate. During the first 5 minutes, incrementally ramp the firing rate to 30 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to the minimum firing rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures must be tested simultaneously and with all burners operational. Results must be reported for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data must be collected continuously throughout the performance test using an electronic Data Acquisition System. A graphic presentation or strip chart of the control device operating data and emissions test data must be included in the test report in accordance with paragraph (d)(12) of this section. Inlet fuel meter data may be manually recorded provided that all inlet fuel data readings are included in the final report.

(4) Inlet testing must be conducted as specified in paragraphs (d)(4)(i) and (ii) of this section.

(i) The inlet gas flow metering system must be located in accordance with EPA Method 2A, 40 CFR part 60, appendix A-1 (or other approved procedure) to measure inlet gas flow rate at the control device inlet location. You must position the fitting for filling fuel sample containers a minimum of eight pipe diameters upstream of any inlet gas flow monitoring meter.

(ii) Inlet flow rate must be determined using EPA Method 2A, 40 CFR part 60, appendix A-1. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute test.

(5) Inlet gas sampling must be conducted as specified in paragraphs (d)(5)(i) and (ii) of this section.

(i) At the inlet gas sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 3-hour period. Filling must be conducted as specified in paragraphs (d)(5)(i)(A) through (C) of this section.

(A) Open the canister sampling valve at the beginning of each test run, and close the canister at the end of each test run.

(B) Fill one canister across the three test runs such that one composite fuel sample exists for each test condition.

(C) Label the canisters individually and record sample information on a chain of custody form.

(ii) Analyze each inlet gas sample using the methods in paragraphs (d)(5)(ii)(A) through (C) of this section. You must include the results in the test report required by paragraph (d)(12) of this section.

(A) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945-03.

(B) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945-03.

(C) Higher heating value using ASTM D3588-98 or ASTM D4891-89.

(6) Outlet testing must be conducted in accordance with the criteria in paragraphs (d)(6)(i) through (v) of this section.

(i) Sample and flow rate must be measured in accordance with paragraphs (d)(6)(i)(A) and (B) of this section.

(A) The outlet sampling location must be a minimum of four equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports must be used.

(B) Flow rate must be measured using EPA Method 1, 40 CFR part 60, appendix A-1 for determining flow measurement traverse point location, and EPA Method 2, 40 CFR part 60, appendix A-1 for measuring duct velocity. If low flow conditions are encountered (*i.e.*, velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer must be used to obtain an accurate flow profile.

(ii) Molecular weight and excess air must be determined as specified in paragraph (d)(7) of this section.

(iii) Carbon monoxide must be determined as specified in paragraph (d)(8) of this section.

(iv) THC must be determined as specified in paragraph (d)(9) of this section.

(v) Visible emissions must be determined as specified in paragraph (d)(10) of this section.

(7) Molecular weight and excess air determination must be performed as specified in paragraphs (d)(7)(i) through (iii) of this section.

(i) An integrated bag sample must be collected during the moisture test required by EPA Method 4, 40 CFR part 60, appendix A-3 following the procedure specified in paragraphs (d)(7)(i)(A) and (B) of this section. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC-TCD) analysis meeting the criteria in paragraphs (d)(7)(i)(C) and (D) of this section.

(A) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(B) Purge the sampling line with stack gas before opening the valve and beginning to fill the bag. Clearly label each bag and record sample information on a chain of custody form.

(C) The bag contents must be vigorously mixed prior to the gas chromatograph analysis.

(D) The GC-TCD calibration procedure in EPA Method 3C, 40 CFR part 60, appendix A-2, must be modified by using EPA Alt-045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, repeat the initial calibration using at least three concentration levels.

(ii) Calculate and report the molecular weight of oxygen, carbon dioxide, methane, and nitrogen in the integrated bag sample and include in the test report specified in paragraph (d)(12) of this section. Moisture must be determined using EPA Method 4, 40 CFR part 60, appendix A-3. Traverse both ports with the EPA Method 4, 40 CFR part 60, appendix A-3, sampling train during each test run. Ambient air must not be introduced into the integrated bag sample required by EPA Method 3C, 40 CFR part 60, appendix A-2, sample during the port change.

(iii) Excess air must be determined using resultant data from the EPA Method 3C tests and EPA Method 3B, 40 CFR part 60, appendix A-2, equation 3B-1, or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only).

(8) Carbon monoxide must be determined using EPA Method 10, 40 CFR part 60, appendix A-4. Run the test simultaneously with EPA Method 25A, 40 CFR part 60, appendix A-7 using the same sampling points. An instrument range of 0-10 parts per million by volume-dry (ppmvd) is recommended.

(9) Total hydrocarbon determination must be performed as specified in paragraphs (d)(9)(i) through (vii) of this section.

(i) Conduct THC sampling using EPA Method 25A, 40 CFR part 60, appendix A-7, except that the option for locating the probe in the center 10 percent of the stack is not allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during each test run.

(ii) A valid test must consist of three EPA Method 25A, 40 CFR part 60, appendix A-7, tests, each no less than 60 minutes in duration.

(iii) A 0-10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0-30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases must be propane in air and be certified through EPA Protocol 1—"EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards".

(v) THC measurements must be reported in terms of ppmvw as propane.

(vi) THC results must be corrected to 3 percent CO_2, as measured by EPA Method 3C, 40 CFR part 60, appendix A-2. You must use the following equation for this diluent concentration correction:

$$C_{corr} = C_{meas}\left(\frac{3}{CO_{2meas}}\right)$$

Where:

C_{meas} = The measured concentration of the pollutant.

CO_{2meas} = The measured concentration of the CO_2 diluent.

3 = The corrected reference concentration of CO_2 diluent.

C_{corr} = The corrected concentration of the pollutant.

(vii) Subtraction of methane or ethane from the THC data is not allowed in determining results.

(10) Visible emissions must be determined using EPA Method 22, 40 CFR part 60, appendix A-7. The test must be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date

and time, must be taken once per test run and the 12 photos included in the test report specified in paragraph (d)(12) of this section.

(11) *Performance test criteria.* (i) The control device model tested must meet the criteria in paragraphs (d)(11)(i)(A) through (D) of this section. These criteria must be reported in the test report required by paragraph (d)(12) of this section.

(A) Results from EPA Method 22, 40 CFR part 60, appendix A-7, results under paragraph (d)(10) of this section with no indication of visible emissions.

(B) Average EPA Method 25A, 40 CFR part 60, appendix A-7, results under paragraph (d)(9) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2.

(C) Average CO emissions determined under paragraph (d)(8) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO_2.

(D) Excess combustion air determined under paragraph (d)(7) of this section equal to or greater than 150 percent.

(ii) The manufacturer must determine a maximum inlet gas flow rate which must not be exceeded for each control device model to achieve the criteria in paragraph (d)(11)(iii) of this section. The maximum inlet gas flow rate must be included in the test report required by paragraph (d)(12) of this section.

(iii) A manufacturer must demonstrate a destruction efficiency of at least 95.0 percent for THC, as propane. A control device model that demonstrates a destruction efficiency of 95.0 percent for THC, as propane, will meet the control requirement for 95.0 percent destruction of VOC required under this rule.

(12) The owner or operator of a combustion control device model tested under this paragraph must submit the information listed in paragraphs (d)(12)(i) through (vi) in the test report. Owners or operators who claim that any of the performance test information being submitted is confidential business information (CBI) must submit a complete file including

information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to Attn: CBI Officer; OAQPS CBIO Room 521; 109 T.W. Alexander Drive; RTP, NC 27711. The same file with the CBI omitted must be submitted to Oil_and_Gas_PT@EPA.GOV.

(i) A full schematic of the control device and dimensions of the device components.

(ii) The maximum net heating value of the device.

(iii) The test fuel gas flow range (in both mass and volume). Include the maximum allowable inlet gas flow rate.

(iv) The air/stream injection/assist ranges, if used.

(v) The test conditions listed in paragraphs (d)(12)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess air range.

(G) Flame arrestor(s).

(H) Burner manifold.

(I) Pilot flame indicator.

(J) Pilot flame design fuel and calculated or measured fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) The test report must include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, strip charts, or other graphic presentations of the data annotated with test times and calibration values.

(e) *Continuous compliance for combustion control devices tested by the manufacturer in accordance with paragraph (d) of this section.* This paragraph applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (d) of this section. Owners or operators must demonstrate that a control device achieves the performance requirements in (d)(11) of this section by installing a device tested under paragraph (d) of this section, complying with the criteria specified in paragraphs (e)(1) through (8) of this section and maintaining the records specified in A.5(a)(6) or E.2(a)(1)(ii).

(1) The inlet gas flow rate must be equal to or less than the maximum specified by the manufacturer.

(2) A pilot flame must be present at all times of operation.

(3) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22, 40 CFR part 60, appendix A-7, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(4) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(5) Following return to operation from maintenance or repair activity, each device must pass an EPA Method 22, 40 CFR part 60, appendix A-7, visual observation as described in paragraph (e)(3) of this section.

(6) If the owner or operator operates a combustion control device model tested under this section, an electronic copy of the performance test results required by this section shall be submitted via email to Oil_and_Gas_PT@EPA.GOV unless the test results for that model of combustion control device are posted at the following Web site: epa.gov/airquality/oilandgas/.

(7) Ensure that each enclosed combustion control device is maintained in a leak free condition.

(8) Operate each control device following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

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G Equipment VOC Leaks at Natural Gas Processing Plants

G.1 Applicability

(a) The group of all equipment, except compressors and sampling connection systems, within a process unit located at an onshore natural gas processing plant.

(b) Equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system, or liquefied natural gas unit is covered by the requirements of section G.2 if it is located at an onshore natural gas processing plant. Equipment not located at the onshore natural gas processing plant site is exempt from the requirements of section G.2.

(c) The equipment within a process unit subject to VOC emission control requirements located at onshore natural gas processing plants is exempt from this section if they are subject to and controlled according to subparts VVa or GGGa of 40 CFR part 60.

G.2 What VOC Emission Requirements Apply to Equipment at a Natural Gas Processing Plant?

(a) You must comply with the requirements of sections G.5.1 through G.5.9, except as provided in section G.3.

(b) You may elect to comply with the requirements of sections G.6.1 and G.6.2, as an alternative.

(c) You must comply with the provisions of sections G.7 and G.8 of this section, except as provided in section G.3.

G.3 What Exceptions Apply to the Equipment Leak VOC Emission Control Requirements for Equipment at Natural Gas Processing Plants?

(a) You may comply with the following exceptions to the provisions of section G.2.

(b)(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in section G.7(b) except as provided in paragraph (b)(4) of this section, and section G.5.2 of this rule.

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3)(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in section G.5.7.

(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

(4)(i) Any pressure relief device that is located in a non-fractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are on-site, instead of within 5 days as specified in paragraph (b)(1) of this section and section G.5.2(b)(1).

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section must be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service that are located at a non-fractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of sections G.5.3(a)(1), G.5.5(a), G.5.9(a), and paragraph (b)(1) of this section.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of sections G.5.3(a)(1), G.5.5(a), G.5.9(a), and paragraph (b)(1) of this section.

(e) An owner or operator may use the following provisions instead of section G.7(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150°C (302°F) as determined by ASTM Method D86-96.

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150°C (302°F) as determined by ASTM Method D86-96.

G.4 How Do I Demonstrate Initial and Continued Compliance with the VOC Emission Control Requirements for Equipment at Natural Gas Processing Plants?

For equipment subject to VOC emission control requirements at natural gas processing plants, initial and continuous compliance with the VOC requirements is demonstrated if you are in compliance with the requirements of sections G.5.1 through G.5.9, except as provided in section G.3; G.6, as an alternative; and G.7 and G.8, except as provided in section G.3

G.5 What VOC Emission Control Requirements Apply to Equipment at Natural Gas Processing Plants

G.5.1 VOC Emission Control Requirements: General

(a) Each owner or operator subject to the provisions of this rule shall demonstrate compliance with the requirements of sections G.5.2 through G.5.8 for all equipment within 180 days and for G.5.9 within 12 months of the compliance date established by your regulatory authority.

(b) Compliance with sections G.5.2 to G.5.9 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in G.7.

G.5.2 What Equipment VOC Emission Control Requirements Apply to Pressure Relief Devices in Gas/Vapor Service?

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in section G.7(c).

(b)(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in section G.5.7.

(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in section G.7(c).

(c) Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in section G.5.8 is exempted from the requirements of paragraphs (a) and (b) of this section.

(d)(1) Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of paragraphs (a) and (b) of this section, provided the owner or operator complies with the requirements in paragraph (d)(2) of this section.

(2) After each pressure release, a new rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in section G.5.7.

G.5.3 What Equipment VOC Emission Control Requirements Apply to Pumps in Light Liquid Service?

(a)(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in G.7(b), except as provided in paragraphs (d), (e), and (f) of this section. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in paragraphs (d), (e), and (f) of this section.

(2) Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal.

(b)(1) The instrument reading that defines a leak is specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) 5,000 parts per million (ppm) or greater for pumps handling polymerizing monomers;

(ii) 2,000 ppm or greater for all other pumps.

(2) If there are indications of liquids dripping from the pump seal, the owner or operator shall follow the procedure specified in either paragraph (b)(2)(i) or (ii) of this section. This requirement does not apply to a pump that was monitored after a previous weekly inspection and the instrument reading was less than the concentration specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable.

(i) Monitor the pump within 5 days as specified in G.7(b). A leak is detected if the instrument reading measured during monitoring indicates a leak as specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable. The leak shall be repaired using the procedures in paragraph (c) of this section.

(ii) Designate the visual indications of liquids dripping as a leak, and repair the leak using either the procedures in paragraph (c) of this section or by eliminating the visual indications of liquids dripping.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in G.5.7.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described in paragraphs (c)(2)(i) and (ii) of this section, where practicable.

(i) Tightening the packing gland nuts;

(ii) Ensuring that the seal flush is operating at design pressure and temperature.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a) of this section, provided the requirements specified in paragraphs (d)(1) through (6) of this section are met.

(1) Each dual mechanical seal system is:

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of G.5.8; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(2) The barrier fluid system is in heavy liquid service or is not in VOC service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4)(i) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(ii) If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the owner or operator shall follow the procedure specified in either paragraph (d)(4)(ii)(A) or (B) of this section prior to the next required inspection.

(A) Monitor the pump within 5 days as specified in G.7(b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 2,000 ppm or greater is measured, a leak is detected.

(B) Designate the visual indications of liquids dripping as a leak.

(5)(i) Each sensor as described in paragraph (d)(3) is checked daily or is equipped with an audible alarm.

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(iii) If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (d)(5)(ii) of this section, a leak is detected.

(6)(i) When a leak is detected pursuant to paragraph (d)(4)(ii)(A) of this section, it shall be repaired as specified in paragraph (c) of this section.

(ii) A leak detected pursuant to paragraph (d)(5)(iii) of this section shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.

(iii) A designated leak pursuant to paragraph (d)(4)(ii)(B) of this section shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.

(e) Any pump that is designated, as described in G.8(a)(5)(ii), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

(1) Has no externally actuated shaft penetrating the pump housing;

(2) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in G.7(c); and

(3) Is tested for compliance with paragraph (e)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(f) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a control device that complies with the requirements of G.5.8, it is exempt from paragraphs (a) through (e) of this section.

(g) Any pump that is designated, as described in G.8(a)(6)(i), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:

(1) The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section; and

(2) The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

(h) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (a)(2) and (d)(4) of this section, and the daily requirements of paragraph (d)(5) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

G.5.4 What Equipment VOC Emission Control Requirements Apply to Open-Ended Valves or Lines?

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in paragraphs (d) and (e) of this section.

(2) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

(b) Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(c) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) of this section at all other times.

(d) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (a) through (c) of this section.

(e) Open-ended valves or lines containing materials which would auto-catalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in paragraphs (a) through (c) of this section are exempt from the requirements of paragraphs (a) through (c) of this section.

G.5.5 What Equipment VOC Emission Control Requirements Apply to Valves in Gas/Vapor Service and in Light Liquid Service?

(a)(1) Each valve shall be monitored monthly to detect leaks by the methods specified in G.7(b) and shall comply with paragraphs (b) through (e) of this section, except as provided in paragraphs (f), (g), and (h) of this section and sections G.6.1 and G.6.2.

(2) A valve that begins operation in gas/vapor service or light liquid service after the compliance date for the process unit must be monitored according to paragraphs (a)(2)(i) or (ii),

except for a valve that replaces a leaking valve and except as provided in paragraphs (f), (g), and (h) of this section and sections G.6.1 and G.6.2.

(i) Monitor the valve as in paragraph (a)(1) of this section. The valve must be monitored for the first time within 30 days after the end of its startup period to ensure proper installation.

(ii) If the existing valves in the process unit are monitored in accordance with section G.6.1 or section G.6.2, count the new valve as leaking when calculating the percentage of valves leaking as described in section G.6.2(b)(5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.

(b) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(c)(1)(i) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(ii) As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator may elect to subdivide the process unit into two or three subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The owner or operator must keep records of the valves assigned to each subgroup.

(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

(d)(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in section G.5.7.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

(1) Tightening of bonnet bolts;

(2) Replacement of bonnet bolts;

(3) Tightening of packing gland nuts;

(4) Injection of lubricant into lubricated packing.

(f) Any valve that is designated, as described in section G.8(a)(5)(ii), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) of this section if the valve:

(1) Has no external actuating mechanism in contact with the process fluid,

(2) Is operated with emissions less than 500 ppm above background as determined by the method specified in section G.7(c), and

(3) Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the permitting authority.

(g) Any valve that is designated, as described in section G.8(a)(6)(i), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section, and

(2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

(h) Any valve that is designated, as described in section G.8(a)(6)(ii), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) The process unit within which the valve is located either has less than 3.0 percent of its total number of valves designated as difficult-to-monitor by the owner or operator.

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

G.5.6 What Equipment VOC Emission Control Requirements Apply to Pumps, Valves, and Connectors in Heavy Liquid Service and Pressure Relief Devices in Light Liquid or Heavy Liquid Service?

(a) If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service, the owner or operator shall follow either one of the following procedures:

(1) The owner or operator shall monitor the equipment within 5 days by the method specified in section G.7(b) and shall comply with the requirements of paragraphs (b) through (d) of this section.

(2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in section G.5.7.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) First attempts at repair include, but are not limited to, the best practices described under sections G.5.3(c)(2) and G.5.5(e).

G.5.7 What Delay of Repair of Equipment Requirements Apply When Equipment Component Leaks Have Been Detected?

(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

(c) Delay of repair for valves and connectors will be allowed if:

(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with section G.5.8.

(d) Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(e) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(f) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

G.5.8 What VOC Emission Control Requirements Apply for Closed Vent Systems and Control Devices?

(a) Owners or operators of closed vent systems and control devices used to comply with provisions of this rule shall comply with the provisions of this section.

(b) Vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95.0 percent or greater.

(c) Each enclosed combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) shall be designed to reduce the mass content of VOC emissions by 95.0 percent or greater in accordance with the requirements of section F(b).

(d) Flares used to comply with this subpart shall comply with the requirements of §60.18.

(e) Owners or operators of control devices used to comply with the provisions of this rule shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs.

(f) Except as provided in paragraphs (i) through (k) of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (f)(1) and (2) of this section.

(1) If the vapor collection system or closed vent system is constructed of hard-piping, the owner or operator shall comply with the requirements specified in paragraphs (f)(1)(i) and (ii) of this section:

(i) Conduct an initial inspection according to the procedures in section G.7(b); and

(ii) Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

(2) If the vapor collection system or closed vent system is constructed of ductwork, the owner or operator shall:

(i) Conduct an initial inspection according to the procedures in section G.7(b); and

(ii) Conduct annual inspections according to the procedures in section G.7(b).

(g) Leaks, as indicated by an instrument reading greater than 500 ppmv above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph (h) of this section.

(1) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(2) Repair shall be completed no later than 15 calendar days after the leak is detected.

(h) Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.

(i) If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section.

(j) Any parts of the closed vent system that are designated, as described in paragraph (l)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (j)(1) and (2) of this section:

(1) The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (f)(1)(i) or (f)(2) of this section; and

(2) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(k) Any parts of the closed vent system that are designated, as described in paragraph (l)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (k)(1) through (3) of this section:

(1) The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(2) The owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and

(3) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

(l) The owner or operator shall record the information specified in paragraphs (l)(1) through (5) of this section.

(1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(3) For each inspection during which a leak is detected, a record of the information specified in section G.8(a)(3).

(4) For each inspection conducted in accordance with section G.7(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(5) For each visual inspection conducted in accordance with paragraph (f)(1)(ii) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(m) Closed vent systems and control devices used to comply with provisions of this rule shall be operated at all times when emissions may be vented to them.

G.5.9 What VOC Emission Control Requirements Apply to Connectors in Gas/Vapor Service and in Light Liquid Service?

(a) The owner or operator shall initially monitor all connectors in the process unit for leaks within12 months of the compliance date. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process changes. If required to monitor because of a process change, the owner or operator is required to monitor only those connectors involved in the process change.

(b) Except as allowed in section G.5.7 or as specified in paragraph (e) of this section, the owner or operator shall monitor all connectors in gas and vapor and light liquid service as specified in paragraphs (a) and (b)(3) of this section.

(1) The connectors shall be monitored to detect leaks by the method specified in section G.7(b) and, as applicable, section G.7(c).

(2) If an instrument reading greater than or equal to 500 ppm is measured, a leak is detected.

(3) The owner or operator shall perform monitoring, subsequent to the initial monitoring required in paragraph (a) of this section, as specified in paragraphs (b)(3)(i) through (iii) of this section, and shall comply with the requirements of paragraphs (b)(3)(iv) and (v) of this section. The required period in which monitoring must be conducted shall be determined from paragraphs (b)(3)(i) through (iii) of this section using the monitoring results from the preceding monitoring period. The percent leaking connectors shall be calculated as specified in paragraph (c) of this section.

(i) If the percent leaking connectors in the process unit was greater than or equal to 0.5 percent, then monitor within 12 months (1 year).

(ii) If the percent leaking connectors in the process unit was greater than or equal to 0.25 percent but less than 0.5 percent, then monitor within 4 years. An owner or operator may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors within 2 years of the start of the monitoring period, provided all connectors have been monitored by the end of the 4-year monitoring period.

(iii) If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in paragraph (b)(3)(iii)(A) of this section and either paragraph (b)(3)(iii)(B) or (b)(3)(iii)(C) of this section, as appropriate.

(A) An owner or operator shall monitor at least 50 percent of the connectors within 4 years of the start of the monitoring period.

(B) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is greater than or equal to 0.35 percent of the monitored connectors, the owner or operator shall monitor as soon as practical, but within the next 6 months, all connectors that have not yet been monitored during the monitoring period. At the conclusion of monitoring, a new monitoring period shall be started pursuant to paragraph (b)(3) of this section, based on the percent of leaking connectors within the total monitored connectors.

(C) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is less than 0.35 percent of the monitored connectors, the owner or operator shall monitor all connectors that have not yet been monitored within 8 years of the start of the monitoring period.

(iv) If, during the monitoring conducted pursuant to paragraphs (b)(3)(i) through (iii) of this section, a connector is found to be leaking, it shall be re-monitored once within 90 days after repair to confirm that it is not leaking.

(v) The owner or operator shall keep a record of the start date and end date of each monitoring period under this section for each process unit.

(c) For use in determining the monitoring frequency, as specified in paragraphs (a) and (b)(3) of this section, the percent leaking connectors as used in paragraphs (a) and (b)(3) of this section shall be calculated by using the following equation:

$$\%C_L = C_L / C_t * 100$$

Where:

$\%C_L$ = Percent of leaking connectors as determined through periodic monitoring required in paragraphs (a) and (b)(3)(i) through (iii) of this section.

C_L = Number of connectors measured at 500 ppm or greater, by the method specified in G.7(b).

C_t = Total number of monitored connectors in the process unit.

(d) When a leak is detected pursuant to paragraphs (a) and (b) of this section, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in section G.5.7. A first attempt at repair as defined in this rule shall be made no later than 5 calendar days after the leak is detected.

(e) Any connector that is designated, as described in section G.8(a)(6)(i), as an unsafe-to-monitor connector is exempt from the requirements of paragraphs (a) and (b) of this section if:

(1) The owner or operator of the connector demonstrates that the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (a) and (b) of this section; and

(2) The owner or operator of the connector has a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (d) of this section if a leak is detected.

(f) *Inaccessible, ceramic, or ceramic-lined connectors.* (1) Any connector that is inaccessible or that is ceramic or ceramic-lined (e.g., porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs (a) and (b) of this section, from the leak repair requirements of paragraph (d) of this section, and from recordkeeping and reporting requirements. An inaccessible connector is one that meets any of the provisions specified in paragraphs (f)(1)(i) through (vi) of this section, as applicable:

(i) Buried;

(ii) Insulated in a manner that prevents access to the connector by a monitor probe;

(iii) Obstructed by equipment or piping that prevents access to the connector by a monitor probe;

(iv) Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to 7.6 meters (25 feet) above the ground;

(v) Inaccessible because it would require elevating the monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold; or

(vi) Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines, or would risk damage to equipment.

(2) If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.

(g) Except for instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (f) of this section, identify the connectors subject to the requirements of this rule. Connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this rule are identified as a group, and the number of connectors subject to the requirements is indicated.

G.6 Alternative Standards

G.6.1 Alternative Standards for Valves—Allowable Percentage of Valves Leaking

(a) An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

(b) The following requirements shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking:

(1) An owner or operator must notify the permitting authority that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in section G.8(b)(4).

(2) A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the permitting authority.

(3) If a valve leak is detected, it shall be repaired in accordance with section G.5.5(d) and (e).

(c) Performance tests shall be conducted in the following manner:

(1) All valves in gas/vapor and light liquid service within the natural gas processing plant subject to VOC emission control requirements shall be monitored within one week by the methods specified in section G.7(b).

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3) The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the natural gas processing plant subject to VOC emission control requirements.

(d) Owners and operators who elect to comply with this alternative standard shall not have a natural gas processing plant subject to the equipment component VOC emission control requirements with a leak percentage greater than 2.0 percent, determined as described in section G.7(h).

G.6.2 Alternative Standards for Valves—Skip Period Leak Detection and Repair

(a)(1) An owner or operator may elect to comply with one of the alternative work practices specified in paragraphs (b)(2) and (3) of this section.

(2) An owner or operator must notify the permitting authority before implementing one of the alternative work practices.

(b)(1) An owner or operator shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in section G.5.5.

(2) After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(3) After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(4) If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in section G.5.5 but can again elect to use this section.

(5) The percent of valves leaking shall be determined as described in section G.7(h).

(6) An owner or operator must keep a record of the percent of valves found leaking during each leak detection period.

(7) A valve that begins operation in gas/vapor service or light liquid service after the compliance date for a process unit following one of the alternative standards in this section must be monitored in accordance with section G.5.5(a)(2)(i) or (ii) before the provisions of this section can be applied to that valve.

G.7 Equipment Leak Test Methods and Procedures

(a) In conducting the performance tests, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section.

(b) The owner or operator shall determine compliance with the standards in sections G.5.2 through G.5.9, and as follows:

(1) EPA Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in EPA Method 21 of appendix A-7 of this part. The following calibration gases shall be used:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppm greater than the leak definition concentration of the equipment monitored. If the monitoring instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppm above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately equal to 10,000 ppm. If only one scale on an instrument will be used during monitoring, the owner or operator need not calibrate the scales that will not be used during that day's monitoring.

(2) A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in EPA Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in section G.8(a)(5)(v). Divide these readings by the initial calibration value and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

(c) The owner or operator shall determine compliance with the no-detectable-emission standards in sections G.5.2, G.5.3(e), G.5.5(f), and G.5.8(e) as follows:

(1) The requirements of paragraph (b) shall apply.

(2) EPA Method 21 of appendix A-7 of this part shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

(d) The owner or operator shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

(1) Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-93, E168-92, or E260-96 must be used.

(2) Organic compounds that are considered by the permitting authority to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

(3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the permitting authority disagrees with the judgment, paragraphs (d)(1) and (2) of this section shall be used to resolve the disagreement.

(e) The owner or operator shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:

(1) The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F). Standard reference texts or ASTM D2879-83, 96, or 97 shall be used to determine the vapor pressures.

(2) The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F) is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(f) Samples used in conjunction with paragraphs (d), (e), and (g) of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

(g) The owner or operator shall determine compliance with the standards of flares as follows:

(1) EPA Method 22 of appendix A-7 of this part shall be used to determine visible emissions.

(2) A thermocouple or any other equivalent device[160] shall be used to monitor the presence of a pilot flame in the flare.

(3) The maximum permitted velocity for air assisted flares shall be computed using the following equation:

$$V_{max} = K_1 + K_2 H_T$$

Where:

V_{max} = Maximum permitted velocity, m/sec (ft/sec).

H_T = Net heating value of the gas being combusted, MJ/scm (Btu/scf).

K_1 = 8.706 m/sec (metric units) = 28.56 ft/sec (English units).

K_2 = 0.7084 m4/(MJ-sec) (metric units) = 0.087 ft^4/(Btu-sec) (English units).

[160] The equivalent device must be reviewed and approved by EPA through the SIP review process.

(4) The net heating value (H_T) of the gas being combusted in a flare shall be computed using the following equation:

$$H_T = K \sum_{i=1}^{n} C_i H_i$$

Where:

K = Conversion constant, 1.740×10^{-7} (g-mole)(MJ)/(ppm-scm-kcal) (metric units) = 4.674×10^{-6} [(g-mole)(Btu)/(ppm-scf-kcal)] (English units).

C_i = Concentration of sample component "i," ppm

H_i = net heat of combustion of sample component "i" at 25°C and 760 mm Hg (77°F and 14.7 psi), kcal/g-mole.

(5) EPA Method 18 of appendix A-6 of this part or ASTM D6420-99 (2004) (where the target compound(s) are those listed in Section 1.1 of ASTM D6420-99, and the target concentration is between 150 parts per billion by volume and 100 ppmv) and ASTM D2504-67, 77, or 88 (Reapproved 1993) shall be used to determine the concentration of sample component "i."

(6) ASTM D2382-76 or 88 or D4809-95 shall be used to determine the net heat of combustion of component "i" if published values are not available or cannot be calculated.

(7) EPA Method 2, 2A, 2C, or 2D of appendix A-7 of this part, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.

(h) The owner or operator shall determine compliance with section G.6.1 or section G.6.2 as follows:

(1) The percent of valves leaking shall be determined using the following equation:

$$\%V_L = (V_L / V_T) * 100$$

Where:

$\%V_L$ = Percent leaking valves.

V_L = Number of valves found leaking.

V_T = The sum of the total number of valves monitored.

(2) The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves only during the monitoring period in which those valves are monitored.

(3) The number of valves leaking shall include valves for which repair has been delayed.

(4) Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.

(5) If the process unit has been subdivided in accordance with section G.5.5(c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.

(6) The total number of valves monitored does not include a valve monitored to verify repair.

G.8 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements*. Each owner or operator subject to the VOC equipment leak requirements specified in section G shall maintain the records specified in paragraphs (a)(1) through (10), as applicable, onsite or at the nearest local field office for at least five years.

(1) An owner or operator of more than one facility subject to the requirements of section G may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

(2) The owner or operator shall record the information specified in paragraphs (a)(2)(i) through (v) of this section for each monitoring event required by sections G.5.3, G.5.5, G.5.6, G.5.9, and G.6.2.

(i) Monitoring instrument identification.

(ii) Operator identification.

(iii) Equipment identification.

(iv) Date of monitoring.

(v) Instrument reading.

(3) When each leak is detected as specified in sections G.5.3, G.5.5, G.5.6, G.5.9, and G.6.2, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number, except when indications of liquids dripping from a pump are designated as a leak.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) Maximum instrument reading measured by EPA Method 21 of appendix A-7 of this part at the time the leak is successfully repaired or determined to be non-repairable, except when a pump is repaired by eliminating indications of liquids dripping.

(v) “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(ix) The date of successful repair of the leak.

(4) The following information pertaining to the design requirements for closed vent systems and control devices described in section G.5.8 shall be recorded and kept in a readily accessible location:

(i) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(ii) The dates and descriptions of any changes in the design specifications.

(iii) A description of the parameter or parameters monitored, as required in section G.5.8(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(iv) Periods when the closed vent systems and control devices required in sections G.5.2 and G.5.3 are not operated as designed, including periods when a flare pilot light does not have a flame.

(v) Dates of startups and shutdowns of the closed vent systems and control devices required in sections G.5.2 and G.5.3.

(5) The following information pertaining to all equipment subject to the requirements in sections G.5.1 to G.5.9 shall be recorded in a log that is kept in a readily accessible location:

(i) A list of identification numbers for equipment subject to the requirements of this rule.

(ii)(A) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of sections G.5.3(e) and G.5.5(f).

(B) The designation of equipment as subject to the requirements of sections G.5.3(e) or section G.5.5(f) shall be signed by the owner or operator. Alternatively, owner or operator may establish a mechanism[161] with their permitting authority that satisfies this requirement.

(C) A list of equipment identification numbers for pressure relief devices required to comply with section G.5.2.

(iii)(A) The dates of each compliance test as required in sections G.5.2, G.5.3(e), and G.5.5(f).

(B) The background level measured during each compliance test.

(C) The maximum instrument reading measured at the equipment during each compliance test.

(iv) A list of identification numbers for equipment in vacuum service.

(v) Records of the information specified in paragraphs (a)(5)(v)(A) through (F) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of EPA Method 21 of appendix A-7 of this part and section G.7(b).

(A) Date of calibration and initials of operator performing the calibration.

(B) Calibration gas cylinder identification, certification date, and certified concentration.

(C) Instrument scale(s) used.

(D) A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of EPA Method 21 of appendix A-7 of this part.

[161] The mechanism must be reviewed and approved by EPA through the SIP review process.

(E) Results of each calibration drift assessment required by section G.7(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).

(F) If an owner or operator makes their own calibration gas, a description of the procedure used.

(vi) The connector monitoring schedule for each process unit as specified in section G.5.9(b)(3)(v).

(vii) Records of each release from a pressure relief device subject to section G.5.2.

(6) The following information pertaining to all valves subject to the requirements of section G.5.5(g) and (h), all pumps subject to the requirements of section G.5.3(g), and all connectors subject to the requirements of section G.5.9(e) shall be recorded in a log that is kept in a readily accessible location:

(i) A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.

(ii) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(7) The following information shall be recorded for valves complying with section G.6.2:

(i) A schedule of monitoring.

(ii) The percent of valves found leaking during each monitoring period.

(8) The following information shall be recorded in a log that is kept in a readily accessible location:

(i) Design criterion required in section G.5.3(d)(5) and explanation of the design criterion; and

(ii) Any changes to this criterion and the reasons for the changes.

(A) The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions:

(*1*) An analysis demonstrating the design capacity of the natural gas processing plant,

(*2*) A statement listing the feed or raw materials and products from the processing plant(s) and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

(*3*) An analysis demonstrating that equipment is not in VOC service.

(9) Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

(10) The following recordkeeping requirements apply to pumps in light liquid service, pressure relief devices in gas/vapor service, valves in gas/vapor service and light liquid service, pumps, valves and connectors in light heavy liquid service and pressure relief devices in light liquid or heavy liquid service, connectors in gas/vapor service and in light liquid service, and alternative standards for valves.

(i) When each leak is detected, as specified in section G.5.2, G.5.3(b)(2), G.5.5, G.5.6, G.5.9 and G.6.2, a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(ii) When each leak is detected, as specified in section G.5.2, G.5.3(b)(2), G.5.5, G.5.6, G.5.9 and G.6.2, the following information must be recorded in a log and shall be kept for 2 years in a readily accessible location:

(A) The instrument and operator identification numbers and the equipment identification number.

(B) The date the leak was detected and the dates of each attempt to repair the leak.

(C) Repair methods applied in each attempt to repair the leak.

(D) “Above 500 ppm” if the maximum instrument reading measured by the methods specified in paragraph (a) of this section after each repair attempt is 500 ppm or greater.

(E) “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(F) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(G) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(H) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(I) The date of successful repair of the leak.

(J) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of section G.5. The designation of equipment that has no detectable emissions that is subject to the provisions of section G.5 must be signed by the owner or operator.

(b) *Reporting requirements*. Each owner or operator subject to the VOC equipment leak requirements shall comply with the reporting requirements of paragraphs (b)(1) through (5).

(1) Each owner or operator subject to the equipment leak VOC emission control requirements of section G.5 shall submit semiannual reports to the permitting authority beginning 6 months after a facility becomes subject to VOC emission control requirements of section G.5.8.

(2) The initial semiannual report to the permitting authority shall include the following information:

(i) Process unit identification.

(ii) Number of valves subject to the requirements of section G.5.5, excluding those valves designated for no detectable emissions under the provisions of section G.5.5(f).

(iii) Number of pumps subject to the requirements of section G.5.3, excluding those pumps designated for no detectable emissions under the provisions of section G.5.3(e) and those pumps complying with section G.5.3(f).

(iv) Number of connectors subject to the requirements of section G.5.9.

(v) Number of pressure relief devices subject to the requirements, except for those pressure relief devices designated for no detectable emissions under the provisions of section G.5.2 (a) and those pressure relief devices complying with section G.5.2 (c).

(3) All semiannual reports to the permitting authority shall include the following information:

(i) Process unit identification.

(ii) For each month during the semiannual reporting period,

(A) Number of valves for which leaks were detected as described in section G.5.5(b) or section G.6.2,

(B) Number of valves for which leaks were not repaired as required in section G.5.5(d)(1),

(C) Number of pumps for which leaks were detected as described in section G.5.3(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),

(D) Number of pumps for which leaks were not repaired as required in section G.5.3(c)(1) and (d)(6),

(E) Number of compressors for which leaks were detected as described in section G.5.3(f),

(F) Number of connectors for which leaks were detected as described in section G.5.9(b)

(G) Number of connectors for which leaks were not repaired as required in section G.5.9(d), and

(H) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(iii) An owner or operator must include the following information in all semiannual reports:

(A) Number of pressure relief devices for which leaks were detected; and

(B) Number of pressure relief devices for which leaks were not repaired.

(iv) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(v) Revisions to items reported according to paragraph (b)(1) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.

(4) An owner or operator electing to comply with the provisions of section G.6.1 or section G.6.2 shall notify the permitting authority of the alternative standard selected 90 days before implementing either of the provisions.

(5) An owner or operator shall report the results of all performance tests to the permitting authority.

G.9 Definitions

As used in this model rule, all terms not defined in section G for equipment leaks at natural gas processing plants shall have the meaning given them in subpart VVa of part 60 and the following terms shall have the specific meanings given them.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

Equipment, as used in the standards and requirements in this rule relative to the equipment leaks of VOC from onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by those same standards and requirements in this rule.

Field gas means feedstock gas entering the natural gas processing plant.

Field gas gathering means the system used transport field gas from a field to the main pipeline in the area.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions. Completion combustion devices include pit flares.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Gas processing plant process unit means equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in sections G.7(e) and G.3(e)(2).

In wet gas service means that a piece of equipment (except compressors and sampling connection systems) contains or contacts the field gas before the extraction step at a gas processing plant process unit.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Non-fractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Process unit means components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Underground storage vessel means a storage vessel stored below ground.

H Pneumatic Pumps: VOC Emissions Control Requirements

H.1 Applicability

Each pneumatic pump, which is a natural gas-driven diaphragm pump located at:

(a) A natural gas processing plant; or

(b) A well site. A natural gas-driven diaphragm pump at a well site that is in operation less than 90 days per calendar year is not a source subject to VOC requirements under this rule provided that the owner/operator keeps records of the days of operation each calendar year and submits such records to the regulatory authority upon request. For the purposes of this rule, any period of operation during a calendar day counts toward the 90 calendar day threshold.

For purposes of the requirements specified in this section, we refer to these pumps as natural gas-driven pneumatic pumps.

H.2 What VOC Emission Reduction Requirements Apply to Natural Gas-Driven Pneumatic Pumps?

For each natural gas-driven pneumatic pump, you must comply with the VOC emission control requirements, based on VOC, in either paragraph (a) or (b)(1) of this section, as applicable.

(a) Each natural gas-driven pneumatic pump at a natural gas processing plant must have a VOC emission rate of zero.

(b)(1) For each natural gas-driven pneumatic pump at a well site, you must reduce natural gas emissions by 95.0 percent, except as provided in paragraphs (b)(2), (3) and (4) of this section.

(2) You are not required to install a control device solely for the purpose of complying with the 95.0 percent reduction requirement of paragraph (b)(1) of this section. If you do not

have a control device installed on site by the compliance date established by your regulatory authority and you do not have the ability to route to a process, then you must comply instead with the provisions of paragraph (b)(2)(i) and (ii) of this section.

(i) Submit a certification in accordance with section H.5(b)(1)(i) in your next annual report, certifying that there is no available control device or process on site and maintain the records in section H.5(a)(1)(i) and (ii).

(ii) If you subsequently install a control device or have the ability to route to a process, you are no longer required to submit the certification in section H.2(b)(2)(i) and must submit the information in section H.5(b)(2) in your next annual report and maintain the records in sections H.5(a)(1)(i), (ii) and (iii) and H.5(a)(2). You must be in compliance with the requirements of paragraph (b)(1) of this section within 30 days of startup of the control device or within 30 days of the ability to route to a process.

(3) If the control device available on site is unable to achieve a 95.0 percent reduction and there is no ability to route the emissions to a process, you must still route the natural gas-driven pneumatic pump's emissions to that existing control device. If you route the pneumatic pump to a control device installed on site that is designed to achieve less than a 95.0 percent reduction, you must submit the information specified in section H.5(b)(1)(iii) in your next annual report and maintain the records in sections H.5(a)(1)(i), (ii) and (iii) and H.5(a)(2).

(4) If you determine, through an engineering assessment, that routing a pneumatic pump to a control device or a process is technically infeasible, the requirements specified in paragraph (b)(4)(i) through (iv) of this section must be met.

(i) You must conduct the assessment of technical infeasibility in accordance with the criteria in paragraph (b)(4)(iii) of this section and have it certified by a qualified professional engineer in accordance with paragraph (b)(4)(ii) of this section.

(ii) The following certification, signed and dated by the qualified professional engineer shall state: "I certify that the assessment of technical infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted and this report was prepared pursuant to the requirements of section H.2(b)(4)(iii) of this rule. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information."

(iii) The assessment of technical feasibility to route emissions from the pneumatic pump to an existing control device on site or to a process must include, but is not limited to, safety considerations, distance from the control device, pressure losses and differentials in the closed vent system and the ability of the control device to handle the pneumatic pump emissions which are routed to them. You must prepare the assessment of technical infeasibility under the direction or supervision of the qualified professional engineer who signs the certification in accordance with paragraph (b)(2)(ii) of this section.

(iv) You must maintain the records specified in section H.5(a)(1)(iv).

(5) If the pneumatic pump is routed to a control device or a process and the control device or process is subsequently removed from the location or is no longer available, you are no longer required to be in compliance with the requirements of paragraph (b)(1) of this section, and instead must comply with paragraph (b)(2) of this section and report the change in your next annual report in accordance with section H.5(b)(2)(iii).

(c) If you use a control device or route to a process to reduce emissions, you must connect the natural gas-driven pneumatic pump subject to VOC emission control requirements through a closed vent system that meets the requirements of section D.1(b).

(d) You must demonstrate initial compliance with standards that apply to natural gas-driven pneumatic pumps subject to VOC emission requirements as required by section H.3.

(e) You must demonstrate continuous compliance with standards that apply to natural gas-driven pneumatic pump sources subject to VOC emission requirements as required by section H.4.

(f) You must perform the reporting as required by section H.5(b) and the recordkeeping as required by H.5(a).

H.3 Initial Compliance Demonstration Requirements

You must demonstrate initial compliance by the compliance date established by your regulatory authority by demonstrating compliance with the VOC emission control requirements for natural gas-driven pneumatic pumps specified in paragraphs (a) through (h) of this section, as applicable.

(a) If you own or operate a pneumatic pump located at a natural gas processing plant, your pneumatic pump must be driven by a gas other than natural gas, resulting in zero VOC emissions.

(b) If you own or operate a natural gas-driven pneumatic pump located at a well site, you must reduce emissions in accordance with section H.2(b)(1), and you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of section D.1(b).

(c) If you own or operate a natural gas-driven pneumatic pump located at a well site and there is no control device or process available on site, you must submit the certification in section H.5(b)(1)(i).

(d) If you own or operate a natural gas-driven pneumatic pump located at a well site, and you are unable to route to an existing control device due to technical infeasibility, and you are unable to route to a process, you must submit the certification in section H.5(b)(1)(ii).

(e) If you own or operate a natural gas-driven pneumatic pump located at a well site and you reduce emissions in accordance with section H.2(b)(3), you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of section D.1(b).

(f) If you are required to collect emissions from a natural gas-driven pneumatic pump through a closed vent system, you must conduct the initial closed vent system inspection required in section D.2 by the date established by your regulatory authority.

(g) You must include a listing of the natural gas-driven pneumatic pumps subject to VOC emission requirements specified in paragraphs (a) through (e) of this section in the initial annual report submitted for your natural gas-driven pneumatic pump according to the requirements of section H.5(b).

(h) You must maintain the records as specified in section H.5(a) for each natural gas-driven pneumatic pump subject to the VOC emission control requirements of section H.

H.4 Continuous Compliance Demonstration Requirements

For each natural gas-driven pneumatic pump you must demonstrate continuous compliance according to paragraphs (a) and (b) of this section.

(a) If you are required to collect emissions from a natural gas-driven pneumatic pump through a closed vent system, you must conduct the periodic closed vent system inspections required in section D.2, as applicable.

(b) You must submit the annual reports required by section H.5(b) and maintain the records as specified in section H.5(a).

H.5 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements*.

(1) For each natural gas-driven pneumatic pump subject to VOC emission control requirements, you must maintain the records identified in paragraphs (a)(1)(i) through (v) of this section, as applicable, onsite or at the nearest local field office for at least five years.

(i) Records of the date that an individual natural gas-driven pneumatic pump is required to comply with the rule (as established by the regulatory authority), location and manufacturer specifications for each natural gas-driven pneumatic pump.

(ii) Records of deviations in cases where the natural gas-driven pneumatic pump was not operated in compliance with the requirements specified in section H.2.

(iii) Records on the control device used for control of emissions from a natural gas-driven pneumatic pump including the installation date, manufacturer's specifications, and if the control device is designed to achieve less than a 95.0 percent emission reduction, a design evaluation or manufacturer's specifications indicating the percentage reduction the control device is designed to achieve.

(iv) Records substantiating a claim according to H.2(b)(4) that it is technically infeasible to capture and route emissions from a pneumatic pump to a control device or process, including the qualified professional engineer certification according to H.2(b)(4)(ii) and the records of the engineering assessment of technical infeasibility performed according to H.2.(b)(4)(iii).

(v) You must retain copies of all certifications, engineering assessments and related records for a period of five years and make them available if directed by the regulatory authority.

(2) If you are required to collect emissions from a natural gas-driven pneumatic pump through a closed vent system, you must maintain the records identified in paragraphs (a)(2)(i) through (iv) of this section, as applicable, onsite or at the nearest local field office for at least five years.

(i) Records of each closed vent system inspection required under section D.2(a) and (b).

(ii) If you are subject to the bypass requirements of section D.1(b)(3), a record of each inspection or a record of each time the key is checked out or a record of each time the alarm is sounded.

(iii) If you are subject to the closed vent system no detectable emissions requirements of section D.2(e), records of the monitoring conducted in accordance with section D.2(e).

(iv) For each closed vent system routing to a control device or process, the records of the assessment conducted according to section D.1(b)(4):

(A) A copy of the assessment conducted according to section D.1(b)(4);

(B) A copy of the certification according to section D.1(b)(4)(i); and

(C) The owner or operator shall retain copies of all certifications, assessments and any related records for a period of five years, and make them available if directed by the regulatory authority.

(b) *Reporting Requirements*.

For each natural gas-driven pneumatic pump subject to VOC emission control requirements, annual reports are required to include the information specified in paragraphs (b)(1) through (4) of this section.

(1) In the initial annual report, a certification that the natural gas-driven pneumatic pump meets one of the conditions described in paragraphs (b)(1)(i), (ii) or (iii) of this section.

(i) No control device or process is available on site.

(ii) A control device or process is available on site and the owner or operator has determined in accordance with H.2(b)(4) that it is technically infeasible to capture and route the emissions to the control device or process.

(iii) Emissions from the natural gas-driven pneumatic pump are routed to a control device or process. If the control device is designed to achieve less than 95.0 percent emissions reduction, specify the percent emissions reductions the control device is designed to achieve.

(2) For any natural gas-driven pneumatic pump which has been previously reported as required under paragraph (b)(1) of this section and for which a change in the reported condition has occurred during the reporting period, provide the identification of the natural gas-driven pneumatic pump and the date it was previously reported and a certification that the pneumatic pump meets one of the conditions described in paragraphs (b)(2)(i), (ii) or (iii) or (iv) of this section.

(i) A control device has been added to the location and the pneumatic pump now reports according to paragraph (b)(1)(iii) of this section.

(ii) A control device has been added to the location and the pneumatic pump now reports according to paragraph (b)(1)(ii) of this section.

(iii) A control device or process has been removed from the location or otherwise is no longer available and the pneumatic pump now report according to paragraph (b)(1)(i) of this section.

(iv) A control device or process has been removed from the location or is otherwise no longer available and the owner or operator has determined in accordance with H.2(b)(4) through an engineering evaluation that it is technically infeasible to capture and route the emissions to another control device or process.

(3) Records of deviations specified in paragraph (a)(1)(ii) of this section that occurred during the reporting period.

(4) If you are required to collect emissions from a natural gas-driven pneumatic pump through a closed vent system, the records specified in paragraphs (a)(2)(i), (ii), (iii) and (iv)(B) of this section.

H.6 Definitions

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including, but not limited to, general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.*, a Regional Administrator of EPA); or

(4) For facilities subject to requirements:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Natural gas-driven diaphragm pump means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Qualified Professional Engineer means an individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge and experience to make the specific technical certifications required under this subpart. Professional engineers making these certifications must be currently licensed in at least one state in which the certifying official is located.

Routed to a process or *route to a process* means the emissions are conveyed via a closed vent system to any enclosed portion of a process that is operational where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well.

I Fugitive Emissions Components VOC Emissions Control Requirements

I.1 Applicability

(a) The collection of fugitive emission components at a well site with wells that produce, on average, greater than 15 barrel equivalents per day. The fugitive emissions requirements of this section do not apply to well sites that only contain wellheads. Whether a separate tank battery surface site is subject to this rule has no effect on the status of a well site that only contains wellheads.

(b) The collection of fugitive emission components at a gathering and boosting station located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or to an oil pipeline.

I.2 What VOC Emission Control Requirements Apply to the Collection of Fugitive Emission Components at a Well Site and a Gathering and Boosting Station?

For fugitive emissions, VOC emission control requirements apply to the collection of fugitive emission components at a well site and gathering and boosting station (that is located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or to an oil pipeline), as specified in paragraphs (a) through (f) of this section for monitoring the collection of fugitive emission components. These requirements are independent of the closed vent system and cover requirements in section D. The collection of fugitive emissions at a well site with a gas to oil ratio of less than 300 scf of gas per barrel of oil produced are subject only to the requirements in paragraph (g) of this section.

(a) You must monitor all fugitive emission components, as defined in section I.6, in accordance with paragraphs (b) through (e) of this section and section I.2(a) and I.3(a). You must repair all sources of fugitive emissions in accordance with paragraph (f) of this section. You must keep records in accordance with section I.5(a) and report in accordance with section I.5(b). For purposes of this section, fugitive emissions are defined as: any visible emission from a fugitive emission component using optical gas imaging or an instrument reading of 500 ppm or greater using EPA Method 21.

(b) You must develop an emissions monitoring plan that covers the collection of fugitive emission components at well sites and gathering and boosting stations within each company-defined area in accordance with paragraphs (c) and (d) of this section.

(c) Fugitive emissions monitoring plans must include the elements specified in paragraphs (c)(1) through (c)(8) of this section, at a minimum.

(1) Frequency for conducting surveys. Monitoring surveys must be conducted at least as frequently as required by sections I.3 and section I.4 of this section.

(2) Technique for determining fugitive emissions (*i.e.*, EPA Method 21 at 40 CFR part 60, appendix A-7, or optical gas imaging).

(3) Manufacturer and model number of fugitive emission detection equipment to be used.

(4) Procedures and timeframes for identifying and fixing fugitive emission components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of paragraph (f) of this section at a minimum.

(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.

(7) If you are using optical gas imaging, your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii) of this section.

(i) Verification that your optical gas imaging equipment meets the specifications of paragraphs (c)(7)(i)(A) and (B) of this section. This verification is an initial verification and may be performed by the facility, by the manufacturer, or by a third party. For purposes of complying with the fugitive emissions monitoring program with optical gas imaging, a fugitive emission is defined as any visible emissions observed using optical gas imaging.

(A) Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.

(B) Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of ≤60 g/hr from a quarter inch diameter orifice.

(ii) Procedure for a daily verification check.

(iii) Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.

(iv) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.

(v) Procedures for conducting surveys, including the items specified in paragraphs (c)(7)(v)(A) through (C) of this section.

(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.

(B) How the operator will deal with adverse monitoring conditions, such as wind.

(C) How the operator will deal with interferences (*e.g.*, steam).

(vi) Training and experience needed prior to performing surveys.

(vii) Procedures for calibration and maintenance. At a minimum, procedures must comply with those recommended by the manufacturer.

(8) If you are using EPA Method 21 at 40 CFR part 60, appendix A-7, your plan must also include the elements specified in paragraphs (c)(8)(i) and (ii) of this section. For the purposes of complying with the fugitive emissions monitoring program using EPA Method 21, a fugitive emission is defined as an instrument reading of 500 ppm or greater.

(i) Verification that your monitoring equipment meets the requirements specified in Section 6.0 of EPA Method 21 at 40 CFR part 60, appendix A-7. For purposes of instrument capability, the fugitive emissions definition shall be 500 ppm or greater methane using a FID-based instrument. If you wish to use an analyzer other than a FID-based instrument, you must develop a site-specific fugitive emission definition that would be equivalent to 500 ppm methane using a FID-based instrument (*e.g.*, 10.6 eV PID with a specified isobutylene concentration as the fugitive emission definition would provide equivalent response to your compound of interest).

(ii) Procedures for conducting surveys. At a minimum, the procedures shall ensure that the surveys comply with the relevant sections of EPA Method 21 at 40 CFR part 60, appendix A-7, including Section 8.3.1.

(d) Each fugitive emissions monitoring plan must include the elements specified in paragraphs (d)(1) through (d)(4) of this section, at a minimum, as applicable.

(1) Sitemap.

(2) If you are using OGI, a defined observation path that ensures that all fugitive emissions components are within sight of the path. The observation path must account for interferences.

(3) If you are using EPA Method 21, your plan must also include a list of fugitive emissions components to be monitored and the method for determining location of fugitive

emissions components to be monitored in the field (*e.g.*, tagging, identification on a process and instrumentation diagram, etc.).

(4) Your plan must also include the written plan developed for all of the fugitive emission components designated as difficult-to-monitor in accordance with section I.4(a)(3), and the written plan for fugitive emission components designated as unsafe-to-monitor in accordance with section I.4(a)(4).

(e) Each monitoring survey shall observe each fugitive emissions component, as defined section I.6, for fugitive emissions.

(f) Each identified source of fugitive emissions shall be repaired or replaced in accordance with paragraphs (f)(1) and (2) of this section. For fugitive emissions components also subject to the repair provisions of sections A.4(d)(4) through (7) and D.2(e)(9) through (12), those provisions apply instead to those closed vent system and covers, and the repair provisions of paragraphs (f)(1) and (2) of this section do not apply to those closed vent systems and covers.

(1) Each identified source of fugitive emissions shall be repaired or replaced as soon as practicable, but no later than 30 calendar days after detection of the fugitive emissions.

(2) If the repair or replacement is technically infeasible, would require a vent blowdown, a gathering and boosting station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next gathering and boosting station shutdown, well shutdown, well shut-in, after an unscheduled, planned or emergency vent blowdown or within 2 years, whichever is earlier.

(3) Each repaired or replaced fugitive emissions component must be resurveyed as soon as practical, but no later than 30 days after being repaired or replaced, to ensure that there are no fugitive emissions.

(i) For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, the operator may resurvey the repaired fugitive emissions components using EPA Method 21 or optical gas imaging within 30 days of being repaired.

(ii) For each repair or replacement that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph must be taken of that component or the component must be tagged for identification purposes. The digital photograph must include the date that the photograph was taken, must clearly identify the component by location within the site (*e.g.*, the latitude and longitude of the component or by other descriptive landmarks visible in the picture).

(iii) Operators that use EPA Method 21 to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (f)(3)(iii)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the EPA Method 21 instrument indicates a concentration of less than 500 ppm above background or when no soap bubbles are observed when the alternative screening procedures specified in section 8.3.3 of EPA Method 21 are used.

(B) Operators must use the EPA Method 21 monitoring requirements specified in paragraph (c)(8)(ii) of this section or the alternative screening procedures specified in section 8.3.3 of EPA Method 21.

(iv) Operators that use optical gas imaging to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (f)(3)(iv)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the optical gas imaging instrument shows no indication of visible emissions.

(B) Operators must use the optical gas imaging monitoring requirements specified in paragraph (c)(7) of this section.

(g) For each well with less than 300 scf of gas per stock tank barrel of oil produced, you must comply with paragraphs (g)(1) and (g)(2) of this section.

(1) You must determine the gas to oil ratio of your well using generally accepted methods.

(2) You must maintain the records specified in section I.5 (a)(4)

I.3 Initial Compliance Demonstration

To achieve initial compliance with the fugitive emission standards for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station, you must comply with paragraphs (a) through (e) or (f), if applicable, of this section.

(a) You must develop a fugitive emissions monitoring plan as required in sections I.2(b), (c), and (d).

(b) You must conduct an initial monitoring survey as required in paragraphs (b)(1) and (2), as applicable

(1) Each well site with a collection of fugitive emissions components must conduct an initial monitoring survey within 60 days of becoming subject to VOC emission control requirements of section I.

(2) Each gathering and boosting station with a collection of fugitive emissions components must conduct an initial monitoring survey within 60 days of being subject to VOC emission control requirements of section I.

(c) You must maintain the records specified in section I.5(a).

(d) You must repair or replace each identified source of fugitive emissions as required in section I.2(f).

(e) You must submit the initial annual report for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station as required in section I.5(b).

(f) You must determine the gas to oil ratio of your well using generally accepted methods and maintain the records specified in section I.5(a)(4).

I.4 Continuous Compliance Demonstration

For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station, you must demonstrate continuous compliance with the fugitive emission standards specified in section I.2 according to paragraphs (a) through (d) or (e), if applicable, of this section.

(a) You must conduct periodic monitoring surveys of each collection of fugitive emissions components at a well site and a gathering and boosting station subject to VOC emission control requirements under section I at the frequencies specified in paragraphs (a)(1) and (a)(2) of this section, with the exceptions noted in paragraphs (a)(3) through (a)(5) of this section.

(1) A monitoring survey of each collection of fugitive emissions components at a well site within a company-defined area must be conducted at least semiannually after the initial survey. Consecutive semiannual monitoring surveys must be conducted at least 4 months apart.

(2) A monitoring survey of the collection of fugitive emissions components at a gathering and boosting station within a company-defined area must be conducted at least quarterly after the initial survey. Consecutive quarterly monitoring surveys must be conducted at least 60 days apart.

(3) Fugitive emissions components that cannot be monitored without elevating the monitoring personnel more than 2 meters above the surface may be designated as difficult-to-monitor. Fugitive emissions components that are designated difficult-to-monitor must meet the specifications of paragraphs (a)(3)(i) through (iv) of this section.

(i) A written plan must be developed for all of the fugitive emissions components designated difficult-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by sections I.2(b), (c), and (d).

(ii) The plan must include the identification and location of each fugitive emissions component designated as difficult-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as difficult-to-monitor is difficult-to-monitor.

(iv) The plan must include a schedule for monitoring the difficult-to-monitor fugitive emissions components at least once per calendar year.

(4) Fugitive emissions components that cannot be monitored because monitoring personnel would be exposed to immediate danger while conducting a monitoring survey may be designated as unsafe-to-monitor. Fugitive emissions components that are designated unsafe-to-monitor must meet the specifications of paragraphs (a)(4)(i) through (iv) of this section.

(i) A written plan must be developed for all of the fugitive emissions components designated unsafe-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by sections I.2(b), (c), and (d).

(ii) The plan must include the identification and location of each fugitive emissions component designated as unsafe-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as unsafe-to-monitor is unsafe-to-monitor.

(iv) The plan must include a schedule for monitoring the fugitive emissions components designated as unsafe-to-monitor.

(5) The requirements of paragraph (a)(2) of this section are waived for any collection of fugitive emissions components at a gathering and boosting station located within an area that has an average calendar month temperature below 0°Fahrenheit for two of three consecutive calendar months of a quarterly monitoring period. The calendar month temperature average for each month within the quarterly monitoring period must be determined using historical monthly average temperatures over the previous three years as reported by a National Oceanic and Atmospheric Administration source or other source approved by the Administrator. The

requirements of paragraph (a)(2) of this section shall not be waived for two consecutive quarterly monitoring periods.

(b) You must repair or replace each identified source of fugitive emissions as required in section I.2(f).

(c) You must maintain the records specified in section I.5(a).

(d) You must submit annual reports for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station as required in section I.5(b).

(e) You must recalculate the gas to oil ratio of your well using generally accepted methods annually and maintain the records as required in section I.5(a)(4).

I.5 Recordkeeping and Reporting Requirements

(a) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station, the records identified in paragraphs (a)(1) through (3), and (a)(4), if applicable of this section shall be maintained onsite or at the nearest local field office for at least five years.

(1) The fugitive emissions monitoring plan as required in I.2(b), (c), and (d).

(2) The records of each monitoring survey as specified in paragraphs (a)(2)(i) through (ix) of this section.

(i) Date of the survey.

(ii) Beginning and end time of the survey.

(iii) Name of operator(s) performing survey. You must note the training and experience of the operator.

(iv) Monitoring instrument used.

(v) When optical gas imaging is used to perform the survey, one or more digital photographs or videos, captured from the optical gas imaging instrument used for conduct of monitoring, of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a gathering and boosting station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital file, the digital photograph or video may consist of an image of the monitoring survey being performed with a separately operating GPS device within the same digital picture or video, provided the latitude and longitude output of the GPS unit can be clearly read in the digital image.

(vi) Fugitive emissions component identification when EPA Method 21 is used to perform the monitoring survey.

(vii) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(viii) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(ix) Documentation of each fugitive emission, including the information specified in paragraphs (a)(2)(ix)(A) through (L) of this section.

(A) Location.

(B) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(C) Number and type of components for which fugitive emissions were detected.

(D) Number and type of difficult-to-monitor and unsafe-to-monitor fugitive emission components monitored.

(E) Instrument reading of each fugitive emissions component that requires repair when EPA Method 21 is used for monitoring.

(F) Number and type of fugitive emissions components that were not repaired as required in section I.2(f).

(G) Number and type of components that were tagged as a result of not being repaired during the monitoring survey when the fugitive emissions were initially found as required in section I.2(f)(3)(ii).

(H) If a fugitive emissions component is not tagged, a digital photograph or video of each fugitive emissions component that could not be repaired during the monitoring survey when the fugitive emissions were initially found as required in section I.2(f)(3)(ii). The digital photograph or video must clearly identify the location of the component that must be repaired. Any digital photograph or video required under this paragraph can also be used to meet the requirements under paragraph (a)(2)(v) of this section, as long as the photograph or video is taken with the optical gas imaging instrument, includes the date and the latitude and longitude are either imbedded or visible in the picture.

(I) Repair methods applied in each attempt to repair the fugitive emissions components.

(J) Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair.

(K) The date of successful repair of the fugitive emissions component.

(L) Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

(3) For the collection of fugitive emissions components at a gathering and boosting station, if a monitoring survey is waived under section I.4(a)(5), you must maintain records of the average calendar month temperature, including the source of the information, for each calendar month of the quarterly monitoring period for which the monitoring survey was waived.

(4) For the collection of fugitive emissions at a well site with a gas to oil ratio of less than 300 scf per stock barrel of oil produced, you must maintain:

(A) A record of the gas to oil ratio analyses documenting a gas to oil ratio of less than 300 scf per stock barrel of oil produced, conducted pursuant to sections I.3(f) and I.4(e).

(B) The location of the well and the United States Well ID Number.

(C) A record of the determination signed by the certifying official. The claim must include a certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

(b) Annual reports shall be submitted for the collection of fugitive emissions components at each well site and the collection of fugitive emissions components at each gathering and boosting station within the company-defined area, that are subject to VOC emission control requirements under section I. Each annual report shall include the records of each monitoring survey including the information specified in paragraphs (b)(1) through (12) of this section. For the collection of fugitive emissions components at a gathering and boosting station, if a monitoring survey is waived under section I.4(a)(5), you must include in your annual report the fact that a monitoring survey was waived and the calendar months that make up the quarterly monitoring period for which the monitoring survey was waived. Multiple collection of fugitive emissions components at a well site or collection of fugitive emissions as a gathering and boosting station subject to VOC emission control requirements under section I may be included in a single annual report.

(1) Date of the survey.

(2) Beginning and end time of the survey.

(3) Name of operator(s) performing survey. If the survey is performed by optical gas imaging, you must note the training and experience of the operator.

(4) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(5) Monitoring instrument used.

(6) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(7) Number and type of components for which fugitive emissions were detected.

(8) Number and type of fugitive emissions components that were not repaired as required in section I.2(f).

(9) Number and type of difficult-to-monitor and unsafe-to-monitor fugitive emission components monitored.

(10) The date of successful repair of the fugitive emissions component.

(11) Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair.

(12) Type of instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

I.6 Definitions

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including, but not limited to, general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.*, a Regional Administrator of EPA); or

(4) For facilities subject to requirements:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Gathering and boosting station means any permanent combination of one or more compressors that collects natural gas from well sites and moves the natural gas at increased pressure into gathering pipelines to the natural gas processing plant or into the pipeline. The combination of one or more compressors located at a well site, or located at an onshore natural gas processing plant, is not a gathering and boosting station for purposes of this section.

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

Intermediate hydrocarbon liquid means any naturally occurring, unrefined petroleum liquid.

Flow line means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

Fugitive emissions component means any component that has the potential to emit fugitive emissions of VOC at a well site or gathering and boosting station including, but not limited to, valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to section A.2(c) or (d) or section D, thief hatches or other openings on a controlled storage vessel not subject to section A, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For purposes of the fugitive emissions standards at section I.1, *well site* also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (*e.g.*, centralized tank batteries).

Wellhead means 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. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

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