ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2010–0505; FRL–9944–75–OAR]

RIN 2060–AS30

Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes amendments to the current new source performance standards (NSPS) and establishes new standards. Amendments to the current standards will improve implementation of the current NSPS. The new standards for the oil and natural gas source category set standards for both greenhouse gases (GHGs) and volatile organic compounds (VOC). Except for the implementation improvements, and the new standards for GHGs, these requirements do not change the requirements for operations covered by the current standards.

DATES: This final rule is effective on August 2, 2016.

The incorporation by reference (IBR) of certain publications listed in the regulations is approved by the Director of the Federal Register as of August 2, 2016.

ADDRESSES: The Environmental Protection Agency (EPA) has established a docket for this action under Docket ID No. EPA–HQ–OAR–2010–0505. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: For further information concerning this action, contact Ms. Amy Hambrick, Sector Policies and Programs Division (E143–05), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541–0964; facsimile number: (919) 541–3470; email address: *hambrick.amy@epa.gov* or Ms. Lisa Thompson, Sector Policies and Programs Division (E143–05), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541–9775; facsimile number: (919) 541–3470; email address: *thompson.lisa@epa.gov.* For other information concerning the EPA's Oil and Natural Gas Sector regulatory program, contact Mr. Bruce Moore, Sector Policies and Programs Division (E143–05), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541–5460; facsimile number: (919) 541–3470; email address: *moore.bruce@epa.gov.*

SUPPLEMENTARY INFORMATION: *Outline.* The information presented in this preamble is presented as follows:

K. Congressional Review Act (CRA)

I. Preamble Acronyms and Abbreviations

Several acronyms and terms are included in this preamble. While this may not be an exhaustive list, to ease the reading of this preamble and for reference purposes, the following terms and acronyms are defined here:

API American Petroleum Institute
bbl Barrel
boe Barrels of Oil Equivalent
BSER Best System of Emissions Reduction
BTEX Benzene, Toluene, Ethylbenzene and Xylenes
CAA Clean Air Act
CBI Confidential Business Information
CFR Code of Federal Regulations
CO_2 Eq. Carbon dioxide equivalent
DCO Document Control Officer
EIA Energy Information Administration
EPA Environmental Protection Agency
GHG Greenhouse Gases
GHGRP Greenhouse Gas Reporting Program
GOR Gas to Oil Ratio
HAP Hazardous Air Pollutants
LDAR Leak Detection and Repair
Mcf Thousand Cubic Feet
NEI National Emissions Inventory
NEMS National Energy Modeling System
NESHAP National Emissions Standards for Hazardous Air Pollutants
NSPS New Source Performance Standards
NTTAA National Technology Transfer and Advancement Act of 1995
OAQPS Office of Air Quality Planning and Standards
OGI Optical Gas Imaging
OMB Office of Management and Budget
PRA Paperwork Reduction Act
PTE Potential to Emit
REC Reduced Emissions Completion
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
scf Standard Cubic Feet
scfh Standard Cubic Feet per Hour
scfm Standard Cubic Feet per Minute
SO_2 Sulfur Dioxide
tpy Tons per Year
TSD Technical Support Document
TTN Technology Transfer Network
UMRA Unfunded Mandates Reform Act
VCS Voluntary Consensus Standards
VOC Volatile Organic Compounds
VRU Vapor Recovery Unit

II. General Information

A. Executive Summary

1. Purpose of This Regulatory Action

The Environmental Protection Agency (EPA) proposed amendments to the New Source Performance Standards (NSPS) at subpart OOOO and proposed new standards at subpart OOOOa on September 18, 2015 (80 FR 56593). The purpose of this action is to finalize both the amendments and the new standards with appropriate adjustments after full consideration of the comments received on the proposal. Prior to proposal, we pursued a structured engagement process with states and stakeholders. Prior to that process, we issued draft white papers addressing a range of technical issues and then solicited comments on the white papers from expert reviewers and the public.

These rules are designed to complement other federal actions as well as state regulations. In particular, the EPA worked closely with the Department of Interior's Bureau of Land Management (BLM) during development of this rulemaking in order to avoid conflicts in requirements between the NSPS and BLM's proposed rulemaking.[1] Additionally, we evaluated existing state and local programs when developing these federal standards and attempted, where possible, to limit potential conflicts with existing state and local requirements.

As discussed at proposal, prior to this final rule, the EPA had established standards for emissions of VOC and sulfur dioxide (SO_2) for several sources in the source category. In this action, the EPA finalizes standards at subpart OOOOa, based on our determination of the best system of emissions reduction (BSER) for reducing emissions of greenhouse gases (GHGs), specifically methane, as well as VOC across a variety of additional emission sources in the oil and natural gas source category (*i.e.,* production, processing, transmission, and storage). The EPA includes requirements for methane emissions in this action because methane is one of the six well-mixed gases in the definition of GHGs and the oil and natural gas source category is one of the country's largest industrial emitters of methane. In 2009, the EPA found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations.

[1] 81 FR 6616, February 8, 2016, *Waste Prevention, Production Subject to Royalties, and Resource Conservation, Proposed Rule.*

In addition to finalizing standards for VOC and GHGs, the EPA is finalizing amendments to improve several aspects of the existing standards at 40 CFR part 60, subpart OOOO related to implementation. These improvements and the setting of standards for GHGs in the form of limitations on methane result from reconsideration of certain issues raised in petitions for reconsideration that were received by the Administrator on the August 16, 2012, NSPS (77 FR 49490) and on the September 13, 2013, amendments (78 FR 58416). These implementation improvements do not change the requirements for operations and equipment covered by the current standards at subpart OOOO.

2. Summary of 40 CFR Part 60, Subpart OOOOa Major Provisions

The final requirements include standards for GHG emissions (in the form of methane emission limitations) and standards for VOC emissions. The NSPS includes both VOC and GHG emission standards for certain new, modified, and reconstructed equipment, processes, and activities across the oil and natural gas source category. These emission sources include the following:

- Sources that are unregulated under the current NSPS at subpart OOOO (hydraulically fractured oil well completions, pneumatic pumps, and fugitive emissions from well sites and compressor stations);
- Sources that are currently regulated at subpart OOOO for VOC, but not for GHGs (hydraulically fractured gas well completions and equipment leaks at natural gas processing plants);
- Certain equipment that is used across the source category, for which the current NSPS at subpart OOOO regulates emissions of VOC from only a subset (pneumatic controllers, centrifugal compressors, and reciprocating compressors), with the exception of compressors located at well sites.

Table 1 below summarizes these sources and the final standards for GHGs (in the form of methane limitations) and VOC emissions. See sections V and VI of this preamble for further discussion.

TABLE 1—SUMMARY OF BSER AND FINAL SUBPART OOOOa STANDARDS FOR EMISSION SOURCES

Source	BSER	Final standards of performance for GHGs and VOC
Wet seal centrifugal compressors (except for those located at well sites) [2].	Capture and route to a control device	95 percent reduction.
Reciprocating compressors (except for those located at well sites) [2].	Regular replacement of rod packing (*i.e.,* approximately every 3 years).	Replace the rod packing on or before 26,000 hours of operation or 36 calendar months or route emissions from the rod packing to a process through a closed vent system under negative pressure.
Pneumatic controllers at natural gas processing plants.	Instrument air systems	Zero natural gas bleed rate.
Pneumatic controllers at locations other than natural gas processing plants.	Installation of low-bleed pneumatic controllers	Natural gas bleed rate no greater than 6 standard cubic feet per hour (scfh).
Pneumatic pumps at natural gas processing plants.	Instrument air systems in place of natural gas driven pumps.	Zero natural gas emissions.
Pneumatic pumps at well sites	Route to existing control device or process	95 percent control if there is an existing control or process on site. 95 percent control not required if (1) routed to an existing control that achieves less than 95 percent or (2) it is technically infeasible to route to the existing control device or process (non-greenfield sites only).
Well completions (subcategory 1: Non-wildcat and non-delineation wells).	Combination of Reduced Emission Completion (REC) and the use of a completion combustion device.	REC in combination with a completion combustion device; venting in lieu of combustion where combustion would present safety hazards. Initial flowback stage: Route to a storage vessel or completion vessel (frac tank, lined pit, or other vessel) and separator. Separation flowback stage: Route all salable gas from the separator to a flow line or collection system, re-inject the gas into the well or another well, use the gas as an onsite fuel source or use for another useful purpose that a purchased fuel or raw material would serve. If technically infeasible to route recovered gas as specified above, recovered gas must be combusted. All liquids must be routed to a storage vessel or well completion vessel, collection system, or be re-injected into the well or another well. The operator is required to have a separator onsite during the entire flowback period.
Well completions (subcategory 2: Exploratory and delineation wells and low pressure wells).	Use of a completion combustion device	The operator is not required to have a separator onsite. Either: (1) Route all flowback to a completion combustion device with a continuous pilot flame; or (2) Route all flowback into one or more well completion vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the flowback before the separator can function is not subject to control under this section. Capture and direct recovered gas to a completion combustion device with a continuous pilot flame. For both options (1) and (2), combustion is not required in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways.
Fugitive emissions from well sites and compressor stations.	For well sites: Monitoring and repair based on semiannual monitoring using optical gas imaging (OGI) [3].	Monitoring and repair of fugitive emission components using OGI with Method 21 as an alternative at 500 parts per million (ppm).
	For compressor stations: Monitoring and repair based on quarterly monitoring using OGI.	A monitoring plan must be developed and implemented and repair of the sources of fugitive emissions must be completed within 30 days of finding fugitive emissions.

TABLE 1—SUMMARY OF BSER AND FINAL SUBPART OOOOa STANDARDS FOR EMISSION SOURCES—Continued

Source	BSER	Final standards of performance for GHGs and VOC
Equipment leaks at natural gas processing plants.	Leak detection and repair at 40 CFR part 60, subpart VVa level of control.	Follow requirements at NSPS part 60, subpart VVa level of control as in the 2012 NSPS.

Reconsiderationissues being addressed. As fully detailed in sections V and VI of this preamble and the Response to Comment (RTC) document, the EPA granted reconsideration of several issues raised in the administrative reconsideration petitions submitted on the 2012 NSPS and subsequent amendments (subpart OOOO). In this final rule, in addition to the new standards described above, the EPA includes certain amendments to the 2012 NSPS at subpart OOOO based on reconsideration of those issues. The amendments to the subpart OOOO requirements are effective on August 2, 2016 and, therefore, do not affect compliance activities completed prior to that date.

These provisions are: Requirements for storage vessel control device monitoring and testing; initial compliance requirements for a bypass device that could divert an emission stream away from a control device; recordkeeping requirements for repair logs for control devices failing a visible emissions test; clarification of the due date for the initial annual report; flare design and operation standards; leak detection and repair (LDAR) for open-ended valves or lines; the compliance period for LDAR for newly affected units; exemption to the notification requirement for reconstruction; disposal of carbon from control devices; the definition of capital expenditure; and continuous control device monitoring requirements for storage vessels and centrifugal compressor affected facilities. We are finalizing changes to address these issues to clarify the current NSPS requirements, improve implementation, and update procedures.

3. Costs and Benefits

The EPA has carefully reviewed the comments and additional data submitted on the costs and benefits associated with this rule. Our conclusion and responses are summarized in section IX of the preamble and addressed in greater detail in the Regulatory Impact Analysis (RIA) and RTC. The measures finalized in this action achieve reductions of GHG and VOC emissions through direct regulation and reduction of hazardous air pollutant (HAP) emissions as a co-benefit of reducing VOC emissions. The data show that these are cost-effective measures to reduce emissions and the rule's benefits outweigh these costs.

The EPA has estimated emissions reductions, benefits, and costs for 2 years of analysis: 2020 and 2025. Therefore, the emissions reductions, benefits, and costs by 2020 and 2025 (*i.e.,* including all emissions reductions, costs, and benefits in all years from 2016 to 2025) would be potentially significantly greater than the estimated emissions reductions, benefits, and costs provided within this rule. Actions taken to comply with the final NSPS are anticipated to prevent significant new emissions in 2020, including 300,000 tons of methane; 150,000 tons of VOC; and 1,900 tons of HAP. The emission reductions anticipated in 2025 are 510,000 tons of methane; 210,000 tons of VOC; and 3,900 tons of HAP. Using a 100-year global warming potential (GWP) of 25, the carbon dioxide-equivalent (CO_2 Eq.) methane emission reductions are estimated to be 6.9 million metric tons CO_2 Eq. in 2020 and 11 million metric tons CO_2 Eq. in 2025. The methane-related monetized climate benefits are estimated to be $360 million in 2020 and $690 million in 2025 using a 3-percent discount rate (model average).[4]

While the only benefits monetized for this rule are GHG-related climate benefits from methane reductions, the rule will also yield benefits from reductions in VOC and HAP emissions and from reductions in methane as a precursor to global background concentrations of tropospheric ozone. The EPA was unable to monetize the benefits of VOC reductions due to the difficulties in modeling the impacts with the current data available. A detailed discussion of these unquantified benefits appears in section IX of this preamble, as well as in the RIA available in the docket.

Several VOC that are commonly emitted in the oil and natural gas source category are HAP listed under Clean Air Act (CAA) section 112(b), including benzene, toluene, ethylbenzene and xylenes (this group is commonly referred to as ''BTEX'') and n-hexane. These pollutants and any other HAP included in the VOC emissions controlled under the NSPS, including requirements for additional sources being finalized in this action, are controlled to the same degree. The co-benefit HAP reductions for the final measures are discussed in the RIA and in the technical support document (TSD), which are included in the public docket for this action.

The HAP reductions from these standards will be meaningful in local communities, as members of these communities and other stakeholders across the country have reported significant concerns to the EPA regarding potential adverse health effects resulting from exposure to HAP emitted from oil and natural gas operations. Importantly, these communities include disadvantaged populations.

The EPA estimates the total capital cost of the final NSPS will be $250 million in 2020 and $360 million in 2025. The estimate of total annualized engineering costs of the final NSPS is $390 million in 2020 and $640 million in 2025 when using a 7-percent discount rate. When estimated revenues from additional natural gas are included, the annualized engineering costs of the final NSPS are estimated to be $320 million in 2020 and $530 million in 2025, assuming a wellhead natural gas price of $4/thousand cubic feet (Mcf). These compliance cost estimates include revenues from recovered natural gas, as the EPA estimates that about 16 billion cubic feet in 2020 and 27 billion cubic feet in 2025 of natural gas will be recovered by implementing the NSPS.

Considering all the costs and benefits of this rule, including the revenues from

[2] See sections VI and VIII of this preamble for detailed discussion on emission sources.

[3] The final fugitive standards apply to low production wells. For the reasons discussed in section VI of the preamble, we are not finalizing the proposed exemption of low production wells from these requirements.

[4] We estimate methane benefits associated with four different values of a 1 ton methane reduction (model average at 2.5-percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). For the purposes of this summary, we present the benefits associated with the model average at a 3-percent discount rate. However, we emphasize the importance and value of considering the full range of social cost of methane values. We provide estimates based on additional discount rates in preamble section IX and in the RIA.

recovered natural gas that would otherwise be vented, this rule results in a net benefit. The quantified net benefits (the difference between monetized benefits and compliance costs) are estimated to be $35 million in 2020 and $170 million in 2025 using a 3-percent discount rate (model average) for climate benefits in both years.[5] All dollar amounts are in 2012 dollars.

B. Does this action apply to me?

Categories and entities potentially affected by this action include:

TABLE 2—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS ACTION

Category	NAICS code [1]	Examples of regulated entities
Industry	211111	Crude Petroleum and Natural Gas Extraction.
	211112	Natural Gas Liquid Extraction.
	221210	Natural Gas Distribution.
	486110	Pipeline Distribution of Crude Oil.
	486210	Pipeline Transportation of Natural Gas.
Federal government		Not affected.
State/local/tribal government		Not affected.

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists the types of entities that the EPA is now aware could potentially be affected by this action. Other types of entities not listed in the table could also be regulated. To determine whether your entity is regulated by this action, you should carefully examine the applicability criteria found in the final rule. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section, your air permitting authority, or your EPA Regional representative listed in 40 CFR 60.4 (General Provisions).

C. Where can I get a copy of this document?

In addition to being available in the docket, an electronic copy of the final action is available on the Internet through the Technology Transfer Network (TTN) Web site. Following signature by the Administrator, the EPA will post a copy of this final action at http://www3.epa.gov/airquality/oilandgas/actions.html. The TTN provides information and technology exchange in various areas of air pollution control. Additional information is also available at the same Web site.

D. Judicial Review

Under section 307(b)(1) of the CAA, judicial review of this final rule is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit by August 2, 2016. Moreover, under section 307(b)(2) of the CAA, the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements. Section 307(d)(7)(B) of the CAA further provides that ''[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review.'' This section also provides a mechanism for the EPA to convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule.'' Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, EPA WJC, 1200 Pennsylvania Ave. NW., Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

III. Background

A. Statutory Background

The EPA's authority for this rule is CAA section 111, which requires the EPA to first establish a list of source categories to be regulated under that section and then establish emission standards for new sources in that source category. Specifically, CAA section 111(b)(1)(A) requires that a source category be included on the list if, ''in [the EPA Administrator's] judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' This determination is commonly referred to as an ''endangerment finding'' and that phrase encompasses both of the ''causes or contributes significantly to'' component and the ''endanger public health or welfare'' component of the determination. Once a source category is listed, CAA section 111(b)(1)(B) requires that the EPA propose and then promulgate ''standards of performance'' for new sources in such source category. Other than the endangerment finding for listing the source category, CAA section 111(b) gives no direction or enumerated criteria concerning what constitutes a source category or what emission sources or pollutants from a given source category should be the subject of standards. Therefore, as long as the EPA makes the requisite endangerment finding for the source category to be listed, CAA section 111 leaves the EPA with the authority and discretion to define the source category, determine the pollutants for which standards should be developed, and identify the emission sources within the source category for which standards of performance should be established.

CAA section 111(a)(1) defines ''a standard of performance'' as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirement) the Administrator determines has been adequately demonstrated.'' This definition makes

[5] Figures may not sum due to rounding.

clear that the standard of performance must be based on controls that constitute ''the best system of emission reduction . . . adequately demonstrated.''

In determining whether a given system of emission reduction qualifies as a BSER, CAA section 111(a)(1) requires that the EPA take into account, among other factors, ''the cost of achieving such reduction.'' As described in section VIII.A of the proposal preamble,[6] in several cases the DC Circuit has elaborated on this cost factor and formulated the cost standard in various ways, stating that the EPA may not adopt a standard the cost of which would be ''exorbitant,''[7] ''greater than the industry could bear and survive,''[8] ''excessive,''[9] or ''unreasonable.''[10] For convenience, in this rulemaking, we use ''reasonableness'' to describe costs, which is well within the bounds established by this jurisprudence.

CAA Section 111(a) does not provide specific direction regarding what metric or metrics to use in considering costs, again affording the EPA considerable discretion in choosing a means of cost consideration.[11] In this rulemaking, we evaluated whether a control cost is reasonable under a number of approaches that we find appropriate for assessing the types of controls at issue. Specifically, we considered a control's cost effectiveness under a ''single pollutant cost-effectiveness'' approach and a ''multipollutant cost-effectiveness'' approach.[12] We also evaluated costs on an industry basis by assessing the new capital expenditures (compared to overall capital expenditures) and the annual compliance costs (compared to overall annual revenue) if the rule were to require such control. For a detailed discussion of these cost approaches, please see section VIII.A of the proposal preamble.

The standard that the EPA develops, based on the BSER, is commonly a numerical emissions limit, expressed as a performance level (in other words, a rate-based standard). As provided in CAA section 111(b)(5), the EPA does not prescribe a particular technological system that must be used to comply with a standard of performance. Rather, sources can select any measure or combination of measures that will achieve the emissions level of the standard.

CAA section 111(h)(1) authorizes the Administrator to promulgate ''a design, equipment, work practice, or operational standard, or combination thereof'' if in his or her judgment, ''it is not feasible to prescribe or enforce a standard of performance.'' CAA section 111(h)(2) provides the circumstances under which prescribing or enforcing a standard of performance is ''not feasible'': Such as, when the pollutant cannot be emitted through a conveyance designed to emit or capture the pollutant, or when there is no practicable measurement methodology for the particular class of sources.

CAA section 111(b)(1)(B) requires the EPA to ''at least every 8 years review and, if appropriate, revise'' performance standards unless the ''Administrator determines that such review is not appropriate in light of readily available information on the efficacy'' of the standard. As mentioned above, once the EPA lists a source category under CAA section 111(b)(1)(A), CAA section 111(b)(1)(B) provides the EPA discretion to determine the pollutants and sources to be regulated. In addition, concurrent with the 8-year review (and though not a mandatory part of the 8-year review), EPA may examine whether to add standards for pollutants or emission sources not currently regulated for that source category.

B. Regulatory Background

In 1979, the EPA published a list of source categories, which include ''crude oil and natural gas production,'' for which the EPA would promulgate standards of performance under CAA section 111(b) of the CAA. See *Priority List and Additions to the List of Categories of Stationary Sources*, 44 FR 49222 (August 21, 1979) (''1979 Priority List''). That list included, in the order of priority for promulgating standards, source categories that the EPA Administrator had determined, pursuant to CAA section 111(b)(1)(A), contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. See 44 FR at 49223, August 21, 1979; see also, 49 FR 2636–37, January 20, 1984.

On June 24, 1985 (50 FR 26122), the EPA promulgated an NSPS for the source category that addressed VOC emissions from leaking components at onshore natural gas processing plants (40 CFR part 60, subpart KKK). On October 1, 1985 (50 FR 40158), a second NSPS was promulgated for the source category that regulates SO_2 emissions from natural gas processing plants (40 CFR part 60, subpart LLL). In 2012, pursuant to its duty under CAA section 111(b)(1)(B) to review and, if appropriate, revise NSPS, the EPA published the final rule, ''Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution'' (40 CFR part 60, subpart OOOO) (''2012 NSPS''). The 2012 NSPS updated the SO_2 standards for sweetening units and VOC standards for equipment leaks at onshore natural gas processing plants. In addition, it established VOC standards for several oil and natural gas-related operations not covered by 40 CFR part 60, subparts KKK and LLL, including gas well completions, centrifugal and reciprocating compressors, natural gas-operated pneumatic controllers, and storage vessels. In 2013 and 2014, the EPA made certain amendments to the 2012 NSPS in order to improve implementation of the standards (78 FR 58416, September 23, 2013, and 79 FR 79018, December 31, 2014). The 2013 amendments focused on storage vessel implementation issues; the 2014 amendments provided clarification of well completion provisions which became fully effective on January 1, 2015. The EPA received petitions for both judicial review and administrative reconsiderations for the 2012 NSPS as well as the subsequent amendments in 2013 and 2014. The litigations are stayed pending the EPA's reconsideration process.[13]

In this rulemaking, the EPA is addressing a number of issues raised in the administrative reconsideration petitions.[14] In addition to addressing the petitions requesting we reconsider our decision to defer regulation of GHGs, these topics, which mostly address implementation in 40 CFR part 60, subpart OOOO, are: Storage vessel control device monitoring and testing provisions; initial compliance requirements for a bypass device that

[6] 80 FR 56593, 56616 (September 18, 2015).

[7] *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999).

[8] *Portland Cement Ass'n* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975).

[9] *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981).

[10] *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981).

[11] See, *e.g., Husqvarna AB* v. *EPA,* 254 F.3d 195, 200 (D.C. Cir. 2001) (where CAA section 213 does not mandate a specific method of cost analysis, the EPA may make a reasoned choice as to how to analyze costs).

[12] As discussed in the proposed rule preamble, we believe that both the single and multipollutant approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. The EPA has considered similar approaches in the past when considering multiple pollutants that are controlled by a given control option. See *e.g.,* 73 FR 64079–64083 and EPA Document ID Nos. EPA–HQ–OAR–2004–0022–0622, EPA–HQ–OAR–2004–0022–0447, EPA–HQ–OAR–2004–0022–0448.

[13] In 2015, the EPA made further amendments to provisions relative to storage vessels and well completions (in particular low pressure wells). No judicial review or administrative reconsideration was sought for the 2015 amendments.

[14] The EPA intends to complete its reconsideration process in a subsequent notice.

could divert an emission stream away from a control device; recordkeeping requirements for repair logs for control devices failing a visible emissions test; clarification of the due date for the initial annual report; emergency flare exemption from routine compliance tests; LDAR for open-ended valves or lines; compliance period for LDAR for newly affected process units; exemption to notification requirement for reconstruction of most types of facilities; and disposal of carbon from control devices.

C. Other Notable Events

To provide relevant context to this final rule, EPA will discuss several notable events. First, in 2009 the EPA found that six well-mixed GHGs—carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—endanger both the public health and the public welfare of current and future generations by causing or contributing to climate change. Oil and natural gas operations are significant emitters of methane. According to data from the Greenhouse Gas Reporting Program (GHGRP), oil and natural gas operations are the second largest stationary source of GHG emissions in the United States (when including both methane emissions and combustion-related GHG emissions at oil and natural gas facilities), second only to fossil fuel electricity generation. See section IV of this preamble which discusses, among other issues, this endangerment finding in more detail.

Second, on August 16, 2012, the EPA published the 2012 NSPS (77 FR 49490). The 2012 NSPS included VOC standards for a number of emission sources in the oil and natural gas source category. Using information available at the time, the EPA also evaluated methane emissions and reductions during the 2012 NSPS rulemaking as a potential co-benefit of regulating VOC. Although information at the time indicated that methane emissions could be significant, the EPA did not take final action in the 2012 NSPS with respect to the regulation of GHG emissions; the EPA noted the impending collection of a large amount of GHG emissions data for this industry through the GHGRP (40 CFR part 98) and expressed its intent to continue its evaluation of methane. As stated previously, the 2012 NSPS was the subject of a number of petitions for judicial review and administrative reconsideration. Litigation is currently stayed pending the EPA's reconsideration process. Controlling methane emissions is an issue raised in several of the administrative petitions for the EPA's reconsideration.

Third, in June 2013, President Obama issued his Climate Action Plan, which included direction to the EPA and five other federal agencies to develop a comprehensive interagency strategy to reduce methane emissions. The plan recognized that methane emissions constitute a significant percentage of domestic GHG emissions, highlighted reductions in methane emissions since 1990, and outlined specific actions that could be taken to achieve additional progress.

Fourth, as a follow-up to the 2013 *Climate Action Plan*, the Administration issued the *Climate Action Plan: Strategy to Reduce Methane Emissions* (the Methane Strategy) in March 2014. The focus on reducing methane emissions reflects the fact that methane is a potent GHG with a 100-year GWP that is 28–36 times greater than that of carbon dioxide.[15] The GWP is a measure of how much additional energy the earth will absorb over 100 years as a result of emissions of a given gas, in relation to carbon dioxide. Methane has an atmospheric life of about 12 years, and because of its potency as a GHG and its atmospheric life, reducing methane emissions is an important step that can be taken to achieve a near-term beneficial impact in mitigating global climate change. The Methane Strategy instructed the EPA to release a series of white papers on several potentially significant sources of methane in the oil and natural gas sector and to solicit input from independent experts. The white papers were released in April 2014 and are discussed in more detail in section III.D of this preamble.[16 17]

Finally, following the *Climate Action Plan* and the Methane Strategy, in January 2015, the Administration announced a new goal to cut methane emissions from the oil and gas sector by 40 to 45 percent from 2012 levels by 2025 and steps to put the United States on a path to achieve this ambitious goal. These actions encompass both commonsense standards and cooperative engagement with states, tribes, and industry. Building on prior actions by the Administration and leadership in states and industry, the announcement laid out a plan for the EPA to address, and if appropriate, propose and set standards for methane and ozone-forming emissions from new and modified sources and to issue Control Technique Guidelines (CTG) to assist states in reducing ozone-forming pollutants from existing oil and natural gas systems in areas that do not meet the health-based standard for ozone.

D. Stakeholder Outreach and Public Hearings

1. White Papers

As mentioned, the Methane Strategy was released in March 2014, as a follow-up to the 2013 *Climate Action Plan*, and directed the EPA to release a series of white papers on several potentially significant sources of methane in the oil and natural gas sector and solicit input from independent experts. The papers were released in April 2014, and the peer review process was completed on June 16, 2014.

The peer review, consisting of 26 sets of comments and more than 43,000 public comment submissions on the white papers, included additional technical information that further clarified our understanding of the emission sources and emission control options.[18] The comments also provided additional data on emissions and the number of sources and pointed out newly published studies that further informed our emission rate estimates. Where appropriate, we used the information and data provided to adjust the control options considered and the impacts estimates that are presented in the TSD to this final rule.

2. Outreach to State, Local and Tribal Governments

Throughout the rulemaking process, the EPA collaborated with state, local, and tribal governments to hear how they have managed regulatory issues and to receive feedback that would help us develop the rule. As discussed in the

[15] IPCC, 2013: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 1535 pp. For the analysis supporting this regulation, we used the methane 100-year GWP of 25 to be consistent with and comparable to key Agency emission quantification programs such as the Inventory of Greenhouse Gas Emissions and Sinks (GHG Inventory), and the Greenhouse Gas Reporting Program (GHGRP). For more information see Preamble section Methane Emissions in the United States and from the Oil and Natural Gas Industry.

[16] *http://www.epa.gov/airquality/oilandgas/methane.html.*

[17] Public comments on the white papers are available in the EPA's nonregulatory docket at *http://www.regulations.gov*, Docket ID No. EPA–HQ–OAR–2014–0557.

[18] The comments received from the peer reviewers are available on the EPA's oil and natural gas white paper Web site (*http://www.epa.gov/airquality/oilandgas/methane.html*). Public comments on the white papers are available in the EPA's nonregulatory docket at *www.regulations.gov*, docket ID #EPA–HQ–OAR–2014–0557.

proposal, 12 states, three tribes, and several local air districts participated in several teleconferences in March and April 2015. The EPA hosted additional teleconferences in September 2015 with the same group of states, tribes, and air districts that the EPA spoke with earlier in the year. In September 2015, the EPA also hosted a webinar series with states, tribes, and interested communities to provide an overview of the proposed rule and an opportunity to ask clarifying questions on the proposal.[19]

The EPA specifically consulted with tribal officials under the ''EPA Policy on Consultation and Coordination with Indian Tribes'' early in the process of developing this regulation to provide them with the opportunity to have meaningful and timely input into its development. Additionally, the EPA spoke with tribal stakeholders throughout the rulemaking process and updated the National Tribal Air Association on the Methane Strategy. Consistent with previous actions affecting the oil and natural gas sector, significant tribal interest exists because of the growth of oil and natural gas production in Indian country.

3. Public Hearings

The EPA hosted three public hearings on the proposed rule in September 2015.[20] The public hearings addressed this rule's proposal and two related actions.[21] All combined, approximately 329 people gave verbal testimony. The transcripts and written comments collected at the hearings are in the public docket for this final rule.[22]

E. Related State and Federal Regulatory Actions

As mentioned, these rules are designed to complement current state and other federal regulations. We carefully evaluated existing state and local programs when developing these federal standards and attempted, where possible, to limit potential conflicts with existing state and local requirements. We recognize that, in some cases, these federal rules may be more stringent than existing programs and, in other cases, may be less stringent than existing programs. We received over 900,000 comments on the proposed rule. After careful consideration of the comments, we are finalizing the standards with revisions where appropriate to reduce emissions of harmful air pollutants, promote gas capture and beneficial use, and provide opportunity for flexibility and expanded transparency in order to yield a consistent and accountable national program that provides a clear path for states and other federal agencies to further align their programs.

During development of these NSPS requirements, we were mindful that some facilities that will be subject to the standards will also be subject to current or future requirements of the Department of Interior's Bureau of Land Management (BLM) rules covering production of natural gas on federal lands.[23] To minimize confusion and unnecessary burden on the part of owners and operators, the EPA and the BLM have maintained an ongoing dialogue during development of this action to identify opportunities for aligning requirements and will continue to coordinate through BLM's final rulemaking and through the agencies' implementation of their respective rules. While we intend for our rule to complement the BLM's action, it is important to recognize that the EPA and the BLM are each operating under different statutory authorities and mandates in developing and implementing their respective rules.

In addition to this final rule, the EPA is working to finalize other related actions. The EPA will finalize the Source Determination for Certain Emissions Units in the Oil and Natural Gas Sector rule, which will clarify the EPA's air permitting rules as they apply to the oil and natural gas industry. Additionally, the EPA plans to finalize the federal implementation plan for the EPA's Indian Country Minor New Source Review (NSR) program for oil and natural gas production sources and natural gas processing sources, which will require compliance with various federal regulations and streamline the permitting process for this rapidly growing industry in Indian country. Lastly, the EPA will also issue Control Techniques Guidelines (CTG) for reducing VOC emissions from existing oil and gas sources in certain ozone nonattainment areas and states in the Ozone Transport Region. This suite of requirements together will help combat climate change, reduce air pollution that harms public health, and provide greater certainty about CAA permitting requirements for the oil and natural gas industry.

Other related programs include the EPA's GHGRP, which requires annual reporting of GHG data and other relevant information from large sources and suppliers in the United States. On October 30, 2009, the EPA published 40 CFR part 98 for collecting information regarding GHG emissions from a broad range of industry sectors (74 FR 56260). Although reporting requirements for petroleum and natural gas systems (40 CFR part 98, subpart W) were originally proposed to be part of 40 CFR part 98 (75 FR 16448, April 10, 2009), the final October 2009 rule did not include the petroleum and natural gas systems source category as one of the 29 source categories for which reporting requirements were finalized. The EPA reproposed subpart W in 2010 (79 FR 18608, April 12, 2010), and a subsequent final rule was published on November 30, 2010, with the requirements for the petroleum and natural gas systems source category at 40 CFR part 98, subpart W (75 FR 74458). Following promulgation, the EPA finalized actions revising subpart W (76 FR 22825, April 25, 2011; 76 FR 59533, September 27, 2011; 76 FR 80554, December 23, 2011; 77 FR 51477, August 24, 2012; 78 FR 25392, May 1, 2013; 78 FR 71904, November 29, 2013; 79 FR 63750, October 24, 2014; 79 FR 70352, November 25, 2014; 80 FR 64262, October 22, 2015).

40 CFR part 98, subpart W includes a wide range of operations and equipment, from wells to processing facilities, to transmission and storage and through to distribution pipelines. Subpart W consists of emission sources in the following segments of the petroleum and natural gas industry: Onshore petroleum and natural gas production, offshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, onshore natural gas processing plants, onshore natural gas transmission compression, onshore natural gas transmission pipeline, underground natural gas storage, liquefied natural gas storage, liquefied natural gas import and export equipment, and natural gas distribution.

On March 10, 2016, the EPA announced the next step in reducing emissions of GHGs, specifically methane, from the oil and natural gas industry: Moving to regulate emissions from existing sources. The Agency will begin with a formal process to require companies operating existing oil and gas sources to provide information to assist in the development of comprehensive

[19] See 80 FR 56609, September 18, 2015.

[20] See 80 FR 51991, August 27, 2015.

[21] Source Determination for Certain Emission Units in the Oil and Natural Gas Sector; Review of New Sources and Modifications in Indian Country: Federal Implementation Plan for Managing Air Emissions from True Minor Sources Engaged in Oil and Natural Gas Production in Indian Country.

[22] See EPA Docket ID No. EPA–HQ–OAR–2010–0505.

[23] See 81 FR 6616, February 8, 2016.

regulations to reduce GHG emissions.[24] An Information Collection Request (ICR) will enable the EPA to gather important information on existing sources of GHG emissions, technologies to reduce those emissions, and the costs of those technologies in the production, gathering, processing, and transmission and storage segments of the oil and natural gas sector. There are hundreds of thousands of existing oil and natural gas sources across the country; some emit small amounts of GHGs, but others emit very large quantities. Through the ICR, the EPA will be seeking a broad range of information that will help us determine how to effectively reduce emissions, including information such as how equipment and emissions controls are, or can be, configured, and what installing those controls entails. The EPA will also be seeking information that will help the Agency identify sources with high emissions and the factors that contribute to those emissions. The ICR will likely apply to the same types of sources covered by the 40 CFR part 60, subparts OOOO and OOOOa, as well as additional sources.

IV. Regulatory Authority

In this section, we describe our authority under CAA section 111(b) to regulate emissions from operations and equipment used across the oil and natural gas industry.

A. The Oil and Natural Gas Source Category Listing Under CAA Section 111(b)(1)(A)

In 1979, the EPA published a list of source categories, including ''crude oil and natural gas production,'' for which the EPA would promulgate standards of performance under section 111(b) of the CAA. *Priority List and Additions to the List of Categories of Stationary Sources,* 44 FR 49222 (August 21, 1979) (''1979 Priority List''). The EPA published the 1979 Priority List as directed by a then new section 111(f) under the CAA amendments of 1977. Clean Air Act section 111(f) set a schedule for the EPA to promulgate regulations under CAA section 111(b)(1)(A); listing ''categories of major stationary sources'' and establishing standards of performance for the listed source categories in the order of priority as determined by the criteria set forth in CAA section 111(f). The 1979 Priority List included, in the order of priority for promulgating standards, source categories that the EPA Administrator had determined, pursuant to CAA section 111(b)(1)(A), to contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. See 44 FR 49222, August 21, 1979; see also 49 FR 2636–37, January 20, 1984. In developing the 1979 Priority List, the EPA first analyzed the data to identify ''major source categories'' and then ranked them in the order of priority for setting standards. Id. Although the EPA defined a ''major source category'' in that listing action as ''those categories for which an average size plant has the potential to emit 100 tons or more per year of any one pollutant,'' [25] the EPA provided notice in that action that ''certain new sources of smaller than average size within these categories may have less than a 100 ton per year emission potential.'' 43 FR 38872, 38873 (August 31, 1978). The EPA thus made clear that sources included within the listed source categories in the 1979 Priority List were not limited to sources that emit at or above the 100 ton level. The EPA's decision to not exclude smaller sources in the 1979 Priority List was consistent with CAA section 111(b), the statutory authority for that listing action and the required standard setting to follow. In requiring that the EPA list source categories and establish standards for the new sources within the listed source categories, CAA section 111(b) does not distinguish between ''major'' or other sources. Similarly, as an example, CAA section 111(e), which prohibits violation of an applicable standard upon its effective date, applies to ''any new source,'' not just major new sources.

As mentioned above, one of the source categories listed in that 1979 Priority List generally covers the oil and natural gas industry. Specifically, with respect to the natural gas industry, it includes production, processing, transmission, and storage. The 1979 Priority List broadly covered the natural gas industry,[26] which was evident in the EPA's analysis at the time of listing.[27] For example, the priority list analysis indicated that the EPA evaluated emissions from various segments of the natural gas industry, such as production and processing. The analysis also showed that the EPA evaluated equipment, such as stationary pipeline compressor engines that are used in various segments of the natural gas industry. The scope of the 1979 Priority List is further demonstrated by the Agency's pronouncements during the NSPS rulemaking that followed the listing. Specifically, in its description of this listed source category in the 1984 preamble to the proposed NSPS for equipment leaks at natural gas processing plants, the EPA described the major emission points of this source category to include process, storage, and equipment leaks; these emissions can be found throughout the various segments of the natural gas industry. 49 FR 2637, January 20, 1984. In addition, the EPA identified emission points not covered by that rulemaking, such as ''well systems field oil and gas separators, wash tanks, settling tanks and other sources.'' *Id.* The EPA explained in that action that it could not regulate these emissions at that time because ''best demonstrated control technology has not been identified.'' *Id.*

The inclusion of various segments of the natural gas industry into the source category listed in 1979 is consistent with this industry's operations and equipment. Operations at production, processing, transmission, and storage facilities are a sequence of functions that are interrelated and necessary for getting the recovered gas ready for distribution.[28] Because they are interrelated, segments that follow others are faced with increases in throughput caused by growth in throughput of the segments preceding (*i.e.,* feeding) them. For example, the relatively recent substantial increases in natural gas production brought about by hydraulic fracturing and horizontal drilling result in increases in the amount of natural gas needing to be processed and moved to market or stored. These increases in production and throughput can cause increases in emissions across the entire natural gas industry. We also note that some equipment (*e.g.,* storage vessels, pneumatic pumps, compressors) are used across the oil and natural gas industry, which further supports considering the industry as one source category. For the reasons stated above, the 1979 Priority List broadly includes the various segments of the natural gas

[24] *https://www3.epa.gov/airquality/oilandgas/pdfs/20160310fs.pdf.*

[25] 44 FR 49222, August 21, 1979.

[26] The process of producing natural gas for distribution involves operations in the various segments of the natural gas industry described above. In contrast, oil production involves drilling/extracting oil, which is immediately followed by distribution offsite to be made into different products.

[27] See Standards of Performance for New Stationary Sources, 43 FR 38872 (August 31, 1978) and Priority List and Additions to the List of Categories of Stationary Sources, 44 FR 49222 (August 21, 1979).

[28] The crude oil production segment of the source category, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline, is more limited in scope than the segments of the natural gas value chain included in the source category. However, increases in production at the well and/or increases in the number of wells coming on line, in turn increase throughput and resultant emissions, similarly to the natural gas segments in the source category.

industry (production, processing, transmission, and storage).

Since issuing the 1979 Priority List, which broadly covers the oil and natural gas industry as explained above, the EPA has promulgated performance standards to regulate SO_2 emissions from natural gas processing and VOC emissions from certain operations and equipment in this industry. In this action, the EPA is regulating an additional pollutant (*i.e.*, GHGs) as well as additional sources from this industry.

As explained above, the EPA, in 1979, determined under section 111(b)(1)(A) that the listed oil and natural gas source category contributes significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. Therefore, the 1979 listing of this source category provides sufficient authority for this action. The listed oil and natural gas source category includes oil [29] and natural gas production, processing, transmission, and storage. For the reasons stated above, the EPA believes that the 1979 listing of this source category provides sufficient authority for this action. However, to the extent that there is any ambiguity in the prior listing, the EPA hereby finalizes, as an alternative, its proposed revision of the category listing to broadly include the oil and natural gas industry. As revised, the listed oil and natural gas source category includes oil [30] and natural gas production, processing, transmission, and storage. In support, the EPA has included in this action the requisite finding under section 111(b)(1)(A) that, in the Administrator's judgment, this source category, as defined above, contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.

To be clear, the EPA's view is that no revision is required for the standards established in this final rule. But even assuming it is, for the reason stated below, there is ample evidence that this source category as a whole (oil and natural gas production, processing, transmission, and storage) contributes significantly to air pollution that may reasonably be anticipated to endanger public health and welfare.

First, through the 1979 Priority List, the EPA determined that the oil and natural gas industry contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. To the extent that the EPA's 1979 determination looked only at certain emissions sources in the industry, clearly the much greater emissions from the broader source category, as defined under a revised listing, would provide even more support for a conclusion that emissions from this category endanger public health or welfare. In addition, the EPA has included immediately below information and analyses regarding public health and welfare impacts from GHGs, VOC, and SO_2 emissions, three of the primary pollutants emitted from the oil and natural gas industry, and the estimated emissions of these pollutants from the oil and natural gas source category. It is evident from this information and analyses that the oil and natural gas source category contributes significantly to air pollution which may reasonably be anticipated to endanger public health and welfare. Therefore, to the extent such a finding were necessary, pursuant to section 111(b)(1)(A), the Administrator hereby determines that, in her judgment, this source category, as defined above, contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.

Provided below are the supporting information and analyses referenced above. Specifically, section IV.B of this preamble describes the public health and welfare impacts from GHGs, VOC and SO_2. Section IV.C of this preamble analyzes the emission contribution of these three pollutants by the oil and natural gas industry.

B. Impacts of GHGs, VOC and SO_2 Emissions on Public Health and Welfare

The oil and natural gas industry emits a wide range of pollutants, including GHGs (such as methane and CO_2), VOC, SO_2, nitrogen oxides (NO_X), hydrogen sulfide (H_2S), carbon disulfide (CS_2) and carbonyl sulfide (COS). See 49 FR 2636, 2637 (January 20, 1984). Although all of these pollutants have significant impacts on public health and welfare, an analysis of every one of these pollutants is not necessary for the Administrator to make a determination under CAA section 111(b)(1)(A); as shown below, the EPA's analysis of GHGs, VOC, and SO_2, three of the primary emissions from the oil and natural gas source category, is sufficient for the Administrator to determine under CAA section 111(b)(1)(A) that the oil and natural gas source category contributes significantly to air pollution which may reasonably be anticipated to endanger public health and welfare.[31]

1. Climate Change Impacts From GHG Emissions

In 2009, based on a large body of robust and compelling scientific evidence, the EPA Administrator issued the Endangerment Finding under CAA section 202(a)(1).[32] In the 2009 Endangerment Finding, the Administrator found that the current, elevated concentrations of GHGs in the atmosphere—already at levels unprecedented in human history—may reasonably be anticipated to endanger the public health and welfare of current and future generations in the United States. We summarize these adverse effects on public health and welfare briefly here.

a. Public Health Impacts Detailed in the 2009 Endangerment Finding

Climate change caused by manmade emissions of GHGs threatens the health of Americans in multiple ways. By raising average temperatures, climate change increases the likelihood of heat waves, which are associated with increased deaths and illnesses. While climate change also increases the likelihood of reductions in cold-related mortality, evidence indicates that the increases in heat mortality will be larger than the decreases in cold mortality in the United States. Compared to a future without climate change, climate change is expected to increase ozone pollution over broad areas of the United States, especially on the highest ozone days and in the largest metropolitan areas with the worst ozone problems, and thereby increase the risk of morbidity and mortality. Climate change is also expected to cause more intense hurricanes and more frequent and intense storms and heavy precipitation, with impacts on other areas of public health, such as the potential for increased deaths, injuries, infectious and waterborne diseases, and stress-related disorders. Children, the elderly, and the poor are among the most vulnerable to these climate-related health effects.

b. Public Welfare Impacts Detailed in the 2009 Endangerment Finding

Climate change impacts touch nearly every aspect of public welfare. Among the multiple threats caused by manmade emissions of GHGs, climate changes are

[29] For the oil industry, the listing includes production, as explained above in footnote 27.

[30] For the oil industry, the listing includes production, as explained above in footnote 27.

[31] We note that the EPA's focus on GHG (in particular methane), VOC, and SO_2 in these analyses, does not in any way limit the EPA's authority to promulgate standards that would apply to other pollutants emitted from the oil and natural gas source category, if the EPA determines in the future that such action is appropriate.

[32] "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act," 74 FR 66496 (December 15, 2009) ("2009 Endangerment Finding").

expected to place large areas of the country at serious risk of reduced water supplies, increased water pollution, and increased occurrence of extreme events such as floods and droughts. Coastal areas are expected to face a multitude of increased risks, particularly from rising sea level and increases in the severity of storms. These communities face storm and flooding damage to property, or even loss of land due to inundation, erosion, wetland submergence, and habitat loss.

Impacts of climate change on public welfare also include threats to social and ecosystem services. Climate change is expected to result in an increase in peak electricity demand. Extreme weather from climate change threatens energy, transportation, and water resource infrastructure. Climate change may also exacerbate ongoing environmental pressures in certain settlements, particularly in Alaskan indigenous communities, and is very likely to fundamentally rearrange United States ecosystems over the 21st century. Though some benefits may help balance adverse effects on agriculture and forestry in the next few decades, the body of evidence points towards increasing risks of net adverse impacts on United States food production, agriculture, and forest productivity as temperatures continue to rise. These impacts are global and may exacerbate problems outside the United States that raise humanitarian, trade, and national security issues for the United States.

c. New Scientific Assessments and Observations

Since the administrative record concerning the 2009 Endangerment Finding closed following the EPA's 2010 Reconsideration Denial, the climate has continued to change, with new records being set for a number of climate indicators such as global average surface temperatures, Arctic sea ice retreat, methane and other GHG concentrations, and sea level rise. Additionally, a number of major scientific assessments have been released that improve understanding of the climate system and strengthen the case that GHGs endanger public health and welfare both for current and future generations. These assessments, from the Intergovernmental Panel on Climate Change (IPCC), United States Global Change Research Program (USGCRP), and National Research Council (NRC), include: IPCC's 2012 *Special Report on Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation* (SREX) and the 2013–2014 Fifth Assessment Report (AR5), USGCRP's 2014 National Climate Assessment, *Climate Change Impacts in the United States* (NCA3), and the NRC's 2010 *Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean* (Ocean Acidification), 2011 *Report on Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia* (Climate Stabilization Targets), 2011 *National Security Implications for U.S. Naval Forces* (National Security Implications), 2011 *Understanding Earth's Deep Past: Lessons for Our Climate Future* (Understanding Earth's Deep Past), 2012 *Sea Level Rise for the Coasts of California, Oregon, and Washington: Past, Present, and Future,* 2012 *Climate and Social Stress: Implications for Security Analysis* (Climate and Social Stress), and 2013 *Abrupt Impacts of Climate Change* (Abrupt Impacts) assessments.

The EPA has carefully reviewed these recent assessments in keeping with the same approach outlined in section VIII.A of the 2009 Endangerment Finding, which was to rely primarily upon the major assessments by the USGCRP, IPCC, and the NRC to provide the technical and scientific information to inform the Administrator's judgment regarding the question of whether GHGs endanger public health and welfare. These assessments addressed the scientific issues that the EPA was required to examine, were comprehensive in their coverage of the GHG and climate change issues, and underwent rigorous and exacting peer review by the expert community, as well as rigorous levels of United States government review.

The findings of the recent scientific assessments confirm and strengthen the conclusion that GHGs endanger public health, now and in the future. The NCA3 indicates that human health in the United States will be impacted by "increased extreme weather events, wildfire, decreased air quality, threats to mental health, and illnesses transmitted by food, water, and disease-carriers such as mosquitoes and ticks." The most recent assessments now have greater confidence that climate change will influence production of pollen that exacerbates asthma and other allergic respiratory diseases such as allergic rhinitis, as well as effects on conjunctivitis and dermatitis. Both the NCA3 and the IPCC AR5 found that increased temperature lengthens the allergenic pollen season for ragweed and that increased CO_2 by itself elevates production of plant-based allergens.

The NCA3 also finds that climate change, in addition to chronic stresses such as extreme poverty, is negatively affecting indigenous peoples' health in the United States through impacts such as reduced access to traditional foods, decreased water quality, and increasing exposure to health and safety hazards. The IPCC AR5 finds that climate change-induced warming in the Arctic and resultant changes in environment (*e.g.,* permafrost thaw, effects on traditional food sources) have significant impacts, observed now and projected, on the health and well-being of Arctic residents, especially indigenous peoples. Small, remote, predominantly indigenous communities are especially vulnerable given their "strong dependence on the environment for food, culture, and way of life; their political and economic marginalization; existing social, health, and poverty disparities; as well as their frequent close proximity to exposed locations along ocean, lake, or river shorelines." [33] In addition, increasing temperatures and loss of Arctic sea ice increases the risk of drowning for those engaged in traditional hunting and fishing.

The NCA3 also finds that children's unique physiology and developing bodies contribute to making them particularly vulnerable to climate change. Impacts on children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. The IPCC AR5 indicates that children are among those especially susceptible to most allergic diseases, as well as health effects associated with heat waves, storms, and floods. The IPCC finds that additional health concerns may arise in low income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households.

Both the NCA3 and IPCC AR5 conclude that climate change will increase health risks that the elderly will face. Older people are at much higher risk of mortality during extreme heat events. Pre-existing health conditions also make older adults more susceptible to cardiac and respiratory impacts of air pollution and to more severe consequences from infectious

[33] IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part B: Regional Aspects.* Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Barros, V.R., C.B. Field, D.J. Dokken, M.D. Mastrandrea, K.J. Mach, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, Cambridge, p. 1581.

and waterborne diseases. Limited mobility among older adults can also increase health risks associated with extreme weather and floods.

The new assessments also confirm and strengthen the conclusion that GHGs endanger public welfare and emphasize the urgency of reducing GHG emissions due to their projections that show GHG concentrations climbing to ever-increasing levels in the absence of mitigation. The NRC assessment, *Understanding Earth's Deep Past,* stated that ''the magnitude and rate of the present GHG increase place the climate system in what could be one of the most severe increases in radiative forcing of the global climate system in Earth history.'' [34] Because of these unprecedented changes, several assessments state that we may be approaching critical, poorly understood thresholds. As stated in the NRC assessment, *Understanding Earth's Deep Past,* ''[a]s Earth continues to warm, it may be approaching a critical climate threshold beyond which rapid and potentially permanent—at least on a human timescale—changes not anticipated by climate models tuned to modern conditions may occur.'' The NRC *Abrupt Impacts* report analyzed abrupt climate change in the physical climate system and abrupt impacts of ongoing changes that, when thresholds are crossed, can cause abrupt impacts for society and ecosystems. The report considered destabilization of the West Antarctic Ice Sheet (which could cause 3 to 4 meters (m) of potential sea level rise) as an abrupt climate impact with unknown but low probability of occurring this century. The report categorized a decrease in ocean oxygen content (with attendant threats to aerobic marine life); increase in intensity, frequency, and duration of heat waves; and increase in frequency and intensity of extreme weather events (droughts, floods, hurricanes, and major storms) as climate impacts with moderate risk of an abrupt change within this century. The NRC Abrupt Impacts report also analyzed the threat of rapid state changes in ecosystems and species extinctions as examples of an irreversible impact that is expected to be exacerbated by climate change. Species at most risk include those whose migration potential is limited, whether because they live on mountaintops or fragmented habitats with barriers to movement, or because climatic conditions are changing more rapidly than the species can move or adapt. While the NRC determined that it is not presently possible to place exact probabilities on the added contribution of climate change to extinction, they did find that there was substantial risk that impacts from climate change could, within a few decades, drop the populations in many species below sustainable levels, thereby committing the species to extinction. Species within tropical and subtropical rainforests, such as the Amazon, and species living in coral reef ecosystems were identified by the NRC as being particularly vulnerable to extinction over the next 30 to 80 years, as were species in high latitude and high elevation regions. Moreover, due to the time lags inherent in the Earth's climate, the NRC Climate Stabilization Targets assessment notes that the full warming from increased GHG concentrations will not be fully realized for several centuries, underscoring that emission activities today carry with them climate commitments far into the future.

Future temperature changes will depend on what emission path the world follows. In its high emission scenario, the IPCC AR5 projects that global temperatures by the end of the century will likely be 2.6 °Celsius to 4.8 °Celsius (4.7° to 8.6 °F) warmer than today. Temperatures on land and in northern latitudes will likely warm even faster than the global average. However, according to the NCA3, significant reductions in emissions would lead to noticeably less future warming beyond mid-century and, therefore, less impact to public health and welfare.

While the amount of rainfall may not change significantly when looked at from the standpoint of global and annual averages, there are expected to be substantial shifts in where and when that precipitation falls. According to the NCA3, regions closer to the poles will see more precipitation while the dry subtropics are expected to expand (colloquially, this has been summarized as wet areas getting wetter and dry regions getting drier). In particular, the NCA3 notes that the western United States, and especially the Southwest, is expected to become drier. This projection is consistent with the recent observed drought trend in the West. At the time of publication of the NCA3, even before the last 2 years of extreme drought in California, tree ring data were already indicating that the region might be experiencing its driest period in 800 years. Similarly, the NCA3 projects that heavy downpours are expected to increase in many regions, with precipitation events in general becoming less frequent but more intense. This trend has already been observed in regions such as the Midwest, Northeast, and upper Great Plains. Meanwhile, the NRC Climate Stabilization Targets assessment found that the area burned by wildfire is expected to grow by 2 to 4 times for 1 °Celsius (1.8 °Fahrenheit) of warming. For 3 °Celsius of warming, the assessment found that nine out of 10 summers would be warmer than all but the 5 percent of warmest summers today; leading to increased frequency, duration, and intensity of heat waves. Extrapolations by the NCA3 also indicate that Arctic sea ice in summer may essentially disappear by mid-century. Retreating snow and ice, and emissions of carbon dioxide and methane released from thawing permafrost, will also amplify future warming.

Since the 2009 Endangerment Finding, the USGCRP NCA3, and multiple NRC assessments have projected future rates of sea level rise that are 40 percent larger to more than twice as large as the previous estimates from the 2007 IPCC 4th Assessment Report. This is due, in part, to improved understanding of the future rate of melt of the Antarctic and Greenland ice sheets. The NRC Sea Level Rise assessment projects a global sea level rise of 0.5 to 1.4 meters (1.6 to 4.6 feet) by 2100. An NRC national security implications assessment suggests that ''the Department of the Navy should expect roughly 0.4 to 2 meters (1.3 to 6.6 feet) global average sea-level rise by 2100,'' [35] and the NRC Climate Stabilization Targets assessment states that an increase of 3 °Celsius will lead to a sea level rise of 0.5 to 1 meter (1.6 to 3.3 feet) by 2100. These assessments continue to recognize that there is uncertainty inherent in accounting for ice sheet processes: It is possible that the ice sheets could melt more quickly than expected, leading to more sea level rise than currently projected. Additionally, local sea level rise can differ from the global total depending on various factors: The east coast of the United States in particular is expected to see higher rates of sea level rise than the global average. For comparison, the NCA3 states that ''five million Americans and hundreds of billions of dollars of property are located in areas that are less than four feet above the local high-tide level,'' and the NCA3 finds that ''[c]oastal infrastructure, including roads, rail lines, energy infrastructure, airports, port facilities, and military bases, are increasingly at risk from sea level rise and damaging

[34] National Research Council, Understanding Earth's Deep Past, p. 138.

[35] NRC, 2011: *National Security Implications of Climate Change for U.S. Naval Forces.* The National Academies Press, p. 28.

storm surges.'' [36] Also, because of the inertia of the oceans, sea level rise will continue for centuries after GHG concentrations have stabilized (though reducing GHG emissions will slow the rate of sea level rise and, therefore, reduce the associated risks and impacts). Additionally, there is a threshold temperature above which the Greenland ice sheet will be committed to inevitable melting: According to the NCA3, some recent research has suggested that even present day CO_2 levels could be sufficient to exceed that threshold.

In general, climate change impacts are expected to be unevenly distributed across different regions of the United States and have a greater impact on certain populations, such as indigenous peoples and the poor. The NCA3 finds climate change impacts such as the rapid pace of temperature rise, coastal erosion, and inundation related to sea level rise and storms, ice and snow melt, and permafrost thaw are affecting indigenous people in the United States. Particularly in Alaska, critical infrastructure and traditional livelihoods are threatened by climate change and, ''[i]n parts of Alaska, Louisiana, the Pacific Islands, and other coastal locations, climate change impacts (through erosion and inundation) are so severe that some communities are already relocating from historical homelands to which their traditions and cultural identities are tied.'' [37] The IPCC AR5 notes, ''Climate-related hazards exacerbate other stressors, often with negative outcomes for livelihoods, especially for people living in poverty (high confidence). Climate-related hazards affect poor people's lives directly through impacts on livelihoods, reductions in crop yields, or destruction of homes and indirectly through, for example, increased food prices and food insecurity.'' [38]

The impacts of climate change outside the United States, as also pointed out in the 2009 Endangerment Finding, will also have relevant consequences on the United States and our citizens. The NRC Climate and Social Stress assessment concluded that it is prudent to expect that some climate events ''will produce consequences that exceed the capacity of the affected societies or global systems to manage and that have global security implications serious enough to compel international response.'' The NRC National Security Implications assessment recommends preparing for increased needs for humanitarian aid; responding to the effects of climate change in geopolitical hotspots, including possible mass migrations; and addressing changing security needs in the Arctic as sea ice retreats.

In addition to future impacts, the NCA3 emphasizes that climate change driven by manmade emissions of GHGs is already happening now and that it is currently having effects in the United States. According to the IPCC AR5 and the NCA3, there are a number of climate-related changes that have been observed recently, and these changes are projected to accelerate in the future. The planet warmed about 0.85 °Celsius (1.5 °Fahrenheit) from 1880 to 2012. It is extremely likely (greater than 95-percent probability) that human influence was the dominant cause of the observed warming since the mid-20th century, and likely (greater than 66-percent probability) that human influence has more than doubled the probability of occurrence of heat waves in some locations. In the Northern Hemisphere, the last 30 years were likely the warmest 30 year period of the last 1,400 years. United States average temperatures have similarly increased by 1.3° to 1.9 °F since 1895, with most of that increase occurring since 1970. Global sea levels rose 0.19 meters (7.5 inches) from 1901 to 2010. Contributing to this rise was the warming of the oceans and melting of land ice. It is likely that 275 gigatons per year of ice melted from land glaciers (not including ice sheets) since 1993, and that the rate of loss of ice from the Greenland and Antarctic ice sheets increased substantially in recent years, to 215 gigatons per year and 147 gigatons per year, respectively, since 2002. For context, 360 gigatons of ice melt is sufficient to cause global sea levels to rise 1 millimeter (mm). Annual mean Arctic sea ice has been declining at 3.5 to 4.1 percent per decade, and Northern Hemisphere snow cover extent has decreased at about 1.6 percent per decade for March and 11.7 percent per decade for June. Permafrost temperatures have increased in most regions since the 1980s by up to 3 °Celsius (5.4 °Fahrenheit) in parts of northern Alaska. Winter storm frequency and intensity have both increased in the Northern Hemisphere. The NCA3 states that the increases in the severity or frequency of some types of extreme weather and climate events in recent decades can affect energy production and delivery, causing supply disruptions, and compromise other essential infrastructure such as water and transportation systems.

In addition to the changes documented in the assessment literature, there have been other climate milestones of note. According to the National Oceanic and Atmospheric Administration (NOAA), atmospheric methane concentrations in 2014 were about 1,823 parts per billion, 150 percent higher than methane concentrations were in the year 1750. After a few years of nearly stable concentrations from 1999 to 2006, methane concentrations have resumed increasing at about 5 parts per billion per year. Concentrations today are likely higher than they have been for at least the past 800,000 years. Arctic sea ice has continued to decline, with September of 2012 marking a new record low in terms of Arctic sea ice extent, 40 percent below the 1979 to 2000 median. Sea level has continued to rise at a rate of 3.2 mm per year (1.3 inches/decade) since satellite observations started in 1993, more than twice the average rate of rise in the 20th century prior to 1993.[39] Also, 2015 was the warmest year globally in the modern global surface temperature record, going back to 1880, breaking the record previously held by 2014; this now means that the last 15 years have been 15 of the 16 warmest years on record.[40]

These assessments and observed changes make it clear that reducing emissions of GHGs across the globe is necessary in order to avoid the worst impacts of climate change and underscore the urgency of reducing emissions now. The NRC Committee on America's Climate Choices listed a number of reasons ''why it is imprudent to delay actions that at least begin the process of substantially reducing emissions.'' [41] For example:

• The faster emissions are reduced, the lower the risks posed by climate change. Delays in reducing emissions could commit the planet to a wide range

---

[36] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment.* United States Global Change Research Program, p. 9.

[37] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment.* United States Global Change Research Program, p. 17.

[38] IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects.* Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, p. 796.

[39] Blunden, J., and D.S. Arndt, Eds., 2015: State of the Climate in 2014. Bull. Amer. Meteor. Soc., 96 (7), S1–S267.

[40] *http://www.ncdc.noaa.gov/sotc/global/201513.*

[41] NRC, 2011: *America's Climate Choices,* The National Academies Press.

of adverse impacts, especially if the sensitivity of the climate to GHGs is on the higher end of the estimated range.

• Waiting for unacceptable impacts to occur before taking action is imprudent because the effects of GHG emissions do not fully manifest themselves for decades and, once manifested, many of these changes will persist for hundreds or even thousands of years.

• In the committee's judgment, the risks associated with doing business as usual are a much greater concern than the risks associated with engaging in strong response efforts.

Methane is also a precursor to ground-level ozone, which can cause a number of harmful effects on health and the environment (see section IV.B.2 of this preamble). Additionally, ozone is a short-lived climate forcer that contributes to global warming. In remote areas, methane is a dominant precursor to tropospheric ozone formation.[42] Approximately 50 percent of the global annual mean ozone increase since preindustrial times is believed to be due to anthropogenic methane.[43] Projections of future emissions also indicate that methane is likely to be a key contributor to ozone concentrations in the future.[44] Unlike NO_X and VOC, which affect ozone concentrations regionally and at hourly time scales, methane emissions affect ozone concentrations globally and on decadal time scales given methane's relatively long atmospheric lifetime compared to these other ozone precursors.[45] Reducing methane emissions, therefore, will contribute to efforts to reduce global background ozone concentrations that contribute to the incidence of ozone-related health effects.[46 47 48] The benefits of such reductions are global and occur in both urban and rural areas.

2. VOC

Many VOC can be classified as HAP (*e.g.,* benzene[49]) which can lead to a variety of health concerns such as cancer and noncancer illnesses (*e.g.,* respiratory, neurological). Further, VOC are one of the key precursors in the formation of ozone. Tropospheric, or ground-level, ozone is formed through reactions of VOC and NO_X in the presence of sunlight. Ozone formation can be controlled to some extent through reductions in emissions of ozone precursors VOC and NO_X. A significantly expanded body of scientific evidence shows that ozone can cause a number of harmful effects on health and the environment. Exposure to ozone can cause respiratory system effects such as difficulty breathing and airway inflammation. For people with lung diseases such as asthma and chronic obstructive pulmonary disease (COPD), these effects can lead to emergency room visits and hospital admissions. Studies have also found that ozone exposure is likely to cause premature death from lung or heart diseases. In addition, evidence indicates that long-term exposure to ozone is likely to result in harmful respiratory effects, including respiratory symptoms and the development of asthma. People most at risk from breathing air containing ozone include: Children; people with asthma and other respiratory diseases; older adults; and people who are active outdoors, especially outdoor workers. An estimated 25.9 million people have asthma in the United States, including almost 7.1 million children. Asthma disproportionately affects children, families with lower incomes, and minorities, including Puerto Ricans, Native Americans/Alaska Natives, and African-Americans.[50]

Scientific evidence also shows that repeated exposure to ozone can reduce growth and have other harmful effects on sensitive plants and trees. These types of effects have the potential to impact ecosystems and the benefits they provide.

3. SO_2

Current scientific evidence links short-term exposures to SO_2, ranging from 5 minutes to 24 hours, with an array of adverse respiratory effects including bronchoconstriction and increased asthma symptoms. These effects are particularly important for asthmatics at elevated ventilation rates (*e.g.,* while exercising or playing).

Studies also show an association between short-term exposure and increased visits to emergency departments and hospital admissions for respiratory illnesses, particularly in at-risk populations including children, the elderly, and asthmatics.

SO_2 in the air can also damage the leaves of plants, decrease their ability to produce food—photosynthesis—and decrease their growth. In addition to directly affecting plants, SO_2, when deposited on land and in estuaries, lakes, and streams, can acidify sensitive ecosystems resulting in a range of harmful indirect effects on plants, soils, water quality, and fish and wildlife (*e.g.,* changes in biodiversity and loss of habitat, reduced tree growth, loss of fish species). Sulfur deposition to waterways also plays a causal role in the methylation of mercury.[51]

C. GHGs, VOC and SO_2 Emissions From the Oil and Natural Gas Source Category

The previous section explains how GHGs, VOCs, and SO_2 emissions are ''air pollution'' that may reasonably be anticipated to endanger public health and welfare. This section provides estimated emissions of these substances from the oil and natural gas source category.

1. Methane Emissions in the United States and From the Oil and Natural Gas Industry

The GHGs addressed by the 2009 Endangerment Finding consist of six well-mixed gases, including methane. For the analysis supporting this regulation, we used the methane 100-year GWP of 25 to be consistent with and comparable to key Agency emission quantification programs such as the Inventory of United States Greenhouse Gas Emissions and Sinks (GHG Inventory), and the GHGRP.[52] The use of the 100-year GWP of 25 for methane value is currently required by the United Nations Framework Convention on Climate Change (UNFCCC) for reporting of national inventories, such as the United States GHG Inventory.

[42] U.S. EPA. 2013. ''Integrated Science Assessment for Ozone and Related Photochemical Oxidants (Final Report).'' EPA–600–R–10–076F. National Center for Environmental Assessment—RTP Division. Available at *http://www.epa.gov/ncea/isa/*.

[43] Myhre, G., D. Shindell, F.-M. Bréon, W. Collins, J. Fuglestvedt, J. Huang, D. Koch, J.-F. Lamarque, D. Lee, B. Mendoza, T. Nakajima, A. Robock, G. Stephens, T. Takemura and H. Zhang, 2013: Anthropogenic and Natural Radiative Forcing. In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. Pg. 680.

[44] *Ibid.*

[45] *Ibid.*

[46] West, J.J., Fiore, A.M. 2005. ''Management of tropospheric ozone by reducing methane emissions.'' *Environ. Sci. Technol.* 39:4685–4691.

[47] Anenberg, S.C., et al. 2009. ''Intercontinental impacts of ozone pollution on human mortality,'' *Environ. Sci. & Technol.* 43: 6482–6487.

[48] Sarofim, M.C., Waldhoff, S.T., Anenberg, S.C. 2015. ''Valuing the Ozone-Related Health Benefits of Methane Emission Controls,'' *Environ. Resource Econ.* DOI 10.1007/s10640–015–9937–6.

[49] Benzene IRIS Assessment: *https://cfpub.epa.gov/ncea/iris2/chemicalLanding.cfm?substance_nmbr=276.*

[50] National Health Interview Survey (NHIS) Data, 2011. *http://www.cdc.gov/asthma/nhis/2011/data.htm.*

[51] U.S. EPA. Intergrated Science Assessment (ISA) for Oxides of Nitrogen and Sulfur Ecological Criteria (2008 Final Report). U.S. Envieronmental Protection Agency, Washington, DC, EPA/600/R–08/082F, 2008.

[52] See, for example, Table A–1 to subpart A of 40 CFR part 98.

Updated estimates for methane GWP have been developed by IPCC (2013).[53] The most recent 100-year GWP estimates for methane range from 28 to 36. In discussing the science and impacts of methane emissions generally, here we use the GWP range of 28 to 36. When presenting emissions estimates, we use the GWP of 25 for consistency and comparability with other emissions estimates in the United States and internationally. Methane has an atmospheric life of about 12 years.

Official United States estimates of national level GHG emissions and sinks are developed by the EPA for the United States GHG Inventory to comply with commitments under the UNFCCC. The United States GHG Inventory, which includes recent trends, is organized by industrial sectors. Natural gas and petroleum systems are the largest emitters of methane in the United States. These systems emit 32 percent of United States anthropogenic methane.

Table 3 below presents total United States anthropogenic methane emissions for the years 1990, 2005, and 2014.

TABLE 3—UNITED STATES METHANE EMISSIONS BY SECTOR

[Million metric ton carbon dioxide equivalent (MMT CO_2 Eq.)]

Sector	1990	2005	2014
Oil and Natural Gas Production, and Natural Gas Processing and Transmission	201	203	232
Landfills	180	154	148
Enteric Fermentation	164	169	164
Coal Mining	96	64	68
Manure Management	37	56	61
Other Methane Sources [54]	95	71	57
Total Methane Emissions	774	717	731

Emissions from the Inventory of United States Greenhouse Gas Emissions and Sinks: 1990–2014 (published April 15, 2016), calculated using GWP of 25. Note: Totals may not sum due to rounding.

Oil and natural gas production and natural gas processing and transmission systems encompass wells, natural gas gathering and processing facilities, storage, and transmission pipelines. These components are all important aspects of the natural gas cycle—the process of getting natural gas out of the ground and to the end user. In the oil industry, some underground crude oil contains natural gas that is entrained in the oil at high reservoir pressures. When oil is removed from the reservoir, associated natural gas is produced.

Methane emissions occur throughout the natural gas industry. They primarily result from normal operations, routine maintenance, fugitive leaks, and system upsets. As gas moves through the system, emissions occur through intentional venting and unintentional leaks. Venting can occur through equipment design or operational practices, such as the continuous bleed of gas from pneumatic controllers (that control gas flows, levels, temperatures, and pressures in the equipment), or venting from well completions during production. In addition to vented emissions, methane losses can occur from leaks (also referred to as fugitive emissions) in all parts of the infrastructure, from connections between pipes and vessels, to valves and equipment.

In petroleum systems, methane emissions result primarily from field production operations, such as venting of associated gas from oil wells, oil storage tanks, and production-related equipment such as gas dehydrators, pig traps, and pneumatic devices.

Tables 4 (a) and (b) below present total methane emissions from natural gas and petroleum systems, and the associated segments of the sector, for years 1990, 2005, and 2014, in MMT CO_2 Eq. (Table 4 (a)) and kilotons (or thousand metric tons) of methane (Table 4 (b)).

TABLE 4(a)—UNITED STATES METHANE EMISSIONS FROM NATURAL GAS AND PETROLEUM SYSTEMS

[MMT CO_2]

Sector	1990	2005	2014
Oil and Natural Gas Production and Natural Gas Processing and Transmission *(Total)*	201	203	232
Natural Gas Production	83	108	109
Natural Gas Processing	21	16	24
Natural Gas Transmission and Storage	59	31	32
Petroleum Production	38	48	67

Emissions from the Inventory of United States Greenhouse Gas Emissions and Sinks: 1990–2014 (published April 15, 2016), calculated using GWP of 25. Note: Totals may not sum due to rounding.

[53] IPCC, 2013: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 1535pp.

[54] Other sources include remaining natural gas distribution, petroleum transport and petroleum refineries, forest land, wastewater treatment, rice cultivation, stationary combustion, abandoned coal mines, petrochemical production, mobile combustion, composting, and several sources emitting less than 1 MMT CO_2 Eq. in 2013.

TABLE 4(b)—UNITED STATES METHANE EMISSIONS FROM NATURAL GAS AND PETROLEUM SYSTEMS

[kt CH_4]

Sector	1990	2005	2014
Oil and Natural Gas Production and Natural Gas Processing and Transmission *(Total)*	8,049	8,131	9,295
Natural Gas Production	3,335	4,326	4,359
Natural Gas Processing	852	655	960
Natural Gas Transmission and Storage	2,343	1,230	1,282
Petroleum Production	1,519	1,921	2,694

Emissions from the Inventory of United States Greenhouse Gas Emissions and Sinks: 1990–2014 (published April 15, 2016), in kt (1,000 tons) of CH_4. Note: Totals may not sum due to rounding.

2. United States Oil and Natural Gas Production and Natural Gas Processing and Transmission GHG Emissions Relative to Total United States GHG Emissions

Relying on data from the United States GHG Inventory, we compared United States oil and natural gas production and natural gas processing and transmission GHG emissions to total United States GHG emissions as an indication of the role this source plays in the total domestic contribution to the air pollution that is causing climate change. In 2014, total United States GHG emissions from all sources were 6,871 MMT CO_2 Eq.

TABLE 5—COMPARISONS OF UNITED STATES OIL AND NATURAL GAS PRODUCTION AND NATURAL GAS PROCESSING AND TRANSMISSION CH_4 EMISSIONS TO TOTAL UNITED STATES GHG EMISSIONS

	2010	2011	2012	2013	2014
Total U.S. Oil & Gas Production and Natural Gas Processing & Transmission methane Emissions (MMT CO_2 Eq.)	207.0	214.3	218.8	228.0	232.4
Share of Total U.S. GHG Inventory	3.0%	3.1%	3.3%	3.4%	3.4%
Total U.S. GHG Emissions (MMT CO_2 Eq.)	6,985	6,865	6,643	6,800	6,870

Emissions from the Inventory of United States Greenhouse Gas Emissions and Sinks: 1990–2014 (published April 15, 2016), calculated using CH_4 GWP of 25. Note: Totals may not sum due to rounding.

In 2014, emissions from oil and natural gas production sources and natural gas processing and transmission sources accounted for 232.4 MMT CO_2 Eq. methane emissions (using a GWP of 25 for methane), accounting for 3.4 percent of total United States domestic GHG emissions. The natural gas and petroleum systems source is the largest emitter of methane in the United States. The sector also emitted 43 MMT of CO_2, mainly from acid gas removal during natural gas processing (24 MMT) and flaring in oil and natural gas production (18 MMT). In total, these emissions (CH_4 and CO_2) account for 4.0 percent of total United States domestic GHG emissions.

Methane is emitted in significant quantities from the oil and natural gas production sources and natural gas processing and transmission sources that are being addressed within this rule.

3. United States Oil and Natural Gas Production and Natural Gas Processing and Transmission GHG Emissions Relative to Total Global GHG Emissions

TABLE 6—COMPARISONS OF UNITED STATES OIL AND NATURAL GAS PRODUCTION AND NATURAL GAS PROCESSING AND TRANSMISSION CH_4 EMISSIONS TO TOTAL GLOBAL GHG EMISSIONS

	2010	2011	2012	2013	2014
Total U.S. Oil & Gas Production and Natural Gas Processing & Transmission methane Emissions (MMT CO_2 Eq.)	207.0	214.3	218.8	228.0	232.4
Share of Total U.S. GHG Inventory	3.0%	3.1%	3.3%	3.4%	3.4%
Total U.S. GHG Emissions (MMT CO_2 Eq.)	6,985	6,865	6,643	6,800	6,870

Emissions from the Inventory of United States Greenhouse Gas Emissions and Sinks: 1990–2014 (published April 15, 2016), calculated using CH_4 GWP of 25.

For additional background information and context, we used 2012 World Resources Institute/Climate Analysis Indicators Tool (WRI/CAIT) and International Energy Agency (IEA) data to make comparisons between United States oil and natural gas production and natural gas processing and transmission emissions and the emissions inventories of entire countries and regions. Though the United States methane emissions from oil and natural gas production and natural gas processing and transmission are a seemingly small fraction (0.5 percent) of total global emissions of all GHG from all sources, ranking United States emissions of methane from oil and natural gas production and natural gas processing and transmission against total GHG emissions for entire countries (using 2012 WRI/CAIT data), shows that these emissions are comparatively large as they exceed the national-level emissions totals for all GHG and all anthropogenic sources for Greece, the Czech Republic, Chile, Belgium, and about 150 other countries.[55] Furthermore, United States emissions of methane from oil and natural gas production and natural gas processing and transmission are greater than the sum of total emissions of 54 of the lowest-emitting countries, using the 2012 WRI/CAIT data set.[56]

4. Global GHG Emissions

TABLE 7—COMPARISONS OF UNITED STATES OIL AND NATURAL GAS PRODUCTION AND NATURAL GAS PROCESSING AND TRANSMISSION CH_4 EMISSIONS TO TOTAL GLOBAL GREENHOUSE GAS EMISSIONS IN 2012

	2012 (MMT CO_2 Eq.)	Total U.S. oil and natural gas production and natural gas processing and transmission share (%)
Total Global GHG Emissions	44,816	0.5

As illustrated by the domestic and global GHG comparison data summarized above, the collective GHG emissions from the oil and natural gas source category are significant, whether the comparison is domestic (where this sector is the largest source of methane emissions, accounting for 32 percent of United States methane and 3.4 percent of total United States emissions of all GHG), global (where this sector, while accounting for 0.5 percent of all global GHG emissions, emits more than the total national emissions of over 150 countries, and combined emissions of over 50 countries), or when both the domestic and global GHG emissions comparisons are viewed in combination. Consideration of the global context is important. GHG emissions from United States oil and natural gas production and natural gas processing and transmission will become globally well-mixed in the atmosphere, and thus will have an effect on the United States regional climate, as well as the global climate as a whole for years and indeed many decades to come.

As was the case in 2009, no single GHG source category dominates on the global scale. While the oil and natural gas source category, like many (if not all) individual GHG source categories, could appear small in comparison to total emissions, in fact, it is a very important contributor in terms of both absolute emissions, and in comparison to other source categories globally or within the United States.

5. VOC Emissions

The EPA National Emissions Inventory (NEI) estimated total VOC emissions from the oil and natural gas sector to be 2,729,942 tons in 2011. This ranks second of all the sectors estimated by the NEI and first of all the anthropogenic sectors in the NEI. These facts only serve to further the notion that emissions from the oil and natural gas sector contribute significantly to harmful air pollution.

6. SO_2 Emissions

The NEI estimated total SO_2 emissions from the oil and natural gas sector to be 74,266 tons in 2011. This ranks 13th of the sectors estimated by the NEI. Again, it is clear that emissions from the oil and natural gas sector contribute significantly to dangerous air pollution.

7. Conclusion

In summary, the 1979 Priority List broadly covers the oil and natural gas industry, including the production, processing, transmission, and storage of natural gas. As such, the 1979 Priority List covers all segments that we are regulating in this rule. To the extent that there is any ambiguity in the prior listing, the EPA hereby finalizes as an alternative its proposed revision of the category listing to broadly include the oil and natural gas industry. As revised, the listed oil and natural gas source category includes oil[57] and natural gas production, processing, transmission, and storage. Pursuant to CAA section 111(b)(1)(A), the Administrator has determined that, in her judgment, this source category, as defined above, contributes significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. In support, the EPA notes its previous determination under CAA section 111(b)(1)(A) for the oil and natural gas source category. In addition, the EPA provides in this section information and analyses detailing the public health and welfare impacts of GHG, VOC and SO_2 emissions and the amount of these emission from the oil and natural gas source category (in particular from the various segments of the natural gas industry). Although the EPA does not believe the revision to the category listing is required for the standards we are promulgating in this action, even assuming it is, the revision is well justified.

D. Establishing GHG Standards in the Form of Limitations on Methane Emissions

A petition for reconsideration of the 2012 NSPS urged that ''EPA must reconsider its failure to adopt standards for the methane pollution released by the oil and gas sector.'' [58] Upon reconsidering the issue, and with the benefit of additional information now available to us, the EPA is establishing GHG standards, in the form of limitations on methane emissions, throughout the oil and natural gas source category.

During the 2012 oil and natural gas NSPS rulemaking, we had a considerable amount of data and a good understanding of VOC emissions from the oil and natural gas industry and the available control options, but data on methane emissions were just emerging at that time. In light of the rapid expansion of this industry and the growing concern with the associated emissions, the EPA proceeded to establish a number of VOC standards in the 2012 NSPS, while indicating in the 2012 rulemaking an intent to revisit methane at a later date when additional information was available from the GHGRP.

We have since received and evaluated considerable additional data, which confirms that the oil and natural gas industry is one of the largest emitters of methane in the United States. As

[55] WRI CAIT Climate Data Explorer. *http://cait.wri.org/*. Accessed March 30, 2016.

[56] *Ibid.*

[57] For the oil industry, the listing includes production, as explained above in footnote 27.

[58] Sierra Club et al., Petition for Reconsideration, In the Matter of: Final Rule Published at 77 FR 49490 (August 16, 2012), titled ''Oil and Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews; Final Rule,'' Docket ID No. EPA–HQ–OAR–2010–0505, RIN 2060–AP76 (2012).

discussed in more detail in section IV.C of this preamble above, the current methane emissions from this industry contribute substantially to nationwide GHG emissions. And these emissions are expected to increase as a result of the rapid growth of this industry.

While the controls used to meet the VOC standards in the 2012 NSPS also reduce methane emissions incidentally, in light of the current and projected future GHG emissions from the oil and natural gas industry, reducing GHG emissions from this source category should not be treated simply as an incidental benefit to VOC reduction; rather, it is something that should be directly addressed through GHG standards in the form of limits on methane emissions under CAA section 111(b) based on direct evaluation of the extent and impact of GHG emissions from this source category and the emission reductions that can be achieved through the best system for their reduction. The standards detailed in this final action will achieve meaningful GHG reductions and will be an important step towards mitigating the impact of GHG emissions on climate change.

In addition, while many of the currently regulated emission sources are equipment used throughout the oil and natural gas industry (*e.g.,* pneumatic controllers, compressors) that emit both VOCs and methane, the VOC standards established in the 2012 NSPS apply only to the equipment located in the production and processing segments. As explained in the 2012 final rule, while our analysis suggested that the remaining pieces of equipment (*i.e.,* those in the transmission and storage segments) are also important to regulate, given the large number of these pieces of equipment and the relatively low level of VOC from individual equipment, the EPA decided that further evaluation is appropriate before taking final action. 77 FR 49490, 49521–2 (August 16, 2012). Based on its analyses in the current rulemaking, the EPA is taking final action to regulate VOC emitted from these remaining pieces of equipment. In addition, the EPA is setting GHG standards (by setting limitations on methane) for these pieces of equipment across the industry. As shown in the TSD, there are cost-effective controls that can simultaneously reduce both methane and VOC emissions from these equipment across the industry, and in many instances, they are cost effective even if all the costs are attributed to methane reduction.[59] Moreover, in addition to the reductions to be achieved, establishing both GHG and VOC standards for equipment across the industry will also promote consistency by providing the same regulatory regime for this equipment throughout the oil and natural gas source category for both VOC and GHG, thereby facilitating implementation and enforcement.[60] Therefore, based on the EPA's evaluation of methane reduction to address the impact of GHGs on climate change in conjunction with VOC reduction, the oil and gas NSPS, as finalized in this action, includes both VOC and GHG standards (in the form of limitations on methane) for a number of equipment across the oil and natural gas industry. It also includes VOC and GHG standards for a number of previously unregulated sources (*i.e.,* oil well completions, fugitive emissions at well sites and compressor stations, and pneumatic pumps).

With respect to the GHG standards contained in this final rule, the EPA identifies the air pollutant as the pollutant GHGs. However, the standards in this rule that are specific to GHGs are expressed in the form of limits on emissions of methane, and not the other constituent gases of the air pollutant GHGs.[61] In this action, we are not establishing a limit on aggregate GHGs or separate emission limits for other GHGs that are not methane. This rule focuses on methane because, among other reasons, it is a GHG that is emitted in large quantities from the oil and gas industry, as explained above in section IV.C of this preamble. Notwithstanding this form of the standard, consistent with other EPA regulations addressing GHGs, the air pollutant regulated in this rule is GHGs; methane is limited as a constituent of the regulated pollutant, GHGs, not as a separate pollutant. This approach is consistent with the approach EPA followed in setting limits for new electric generating units.[62] Additional regulatory language has been added to 40 CFR 60.5360a to clarify and confirm that GHGs is the regulated pollutant.

The EPA's authority for regulating GHGs in this rule is CAA section 111(b)(1). As discussed above, under the statutory structure of CAA section 111(b), the Administrator first lists source categories pursuant to CAA section 111(b)(1)(A), and then promulgates, under CAA section 111(b)(1)(B), ''standards of performance for new sources within such category.''

In this rule, the EPA is establishing standards under CAA section 111(b)(1)(B) for a source category that it has previously listed and regulated for other pollutants and which now is being regulated for an additional pollutant.[63] Because of this, there are two aspects of CAA section 111(b)(1) that warrant particular discussion.

First, because the EPA is not listing a new source category in this rule,[64] the EPA is not required to make a new endangerment finding with regard to the oil and natural gas source category in order to establish standards of performance for an additional pollutant from those sources. Under the plain language of CAA section 111(b)(1)(A), an endangerment finding is required only to list a source category. Though the endangerment finding is based on determinations as to the health or welfare impacts of the pollution to which the source category's pollutants contribute, and as to the significance of the amount of such contribution, the statute is clear that the endangerment

[59] In this action, we evaluated the controls under different approaches, including a single pollutant approach and a multi-pollutant approach, which are described in detail in the preamble to the proposed rule and the final TSD. Under a single pollutant approach, we attribute all costs to one pollutant and zero to the other.

[60] While this final rule will result in additional reductions, as specified in sections II and IX of this preamble, the EPA often revises standards even where the revision will not lead to any additional reductions of a pollutant because another standard regulates a different pollutant using the same control equipment. For example, in 2014, the EPA revised the Kraft Pulp Mill NSPS in 40 CFR part 60 subpart BB published at 70 FR 18952 (April 4, 2014) to align the NSPS standards with the National Emission Standards for Hazardous Air Pollutants (NESHAP) standards for those sources in 40 CFR part 63, subpart S. Although no previously unregulated sources were added to the Kraft Pulp Mill NSPS, several emission limits were adjusted downward. The revised NSPS did not achieve additional reductions beyond those achieved by the NESHAP, but aligning the NSPS with the NEHSAP eased the compliance burden for the sources.

[61] In the 2009 GHG Endangerment Finding, the EPA defined the relevant ''air pollution'' as the atmospheric mix of six long-lived and directly emitted GHGs: CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6. 74 FR 66497, December 15, 2009.

[62] See 80 FR 64510 (October 23, 2015).

[63] As explained in more detail in section IV.A of this preamble, the EPA interprets the 1979 category listing to broadly cover the oil and natural gas industry. Thus, this discussion focuses on EPA's authority to regulate an additional pollutant (specifically GHG) emitted from a previously listed source category. However, to the extent that any ambiguity exists in the 1979 listing, and as also explained above, EPA is finalizing its alternative proposal to revise the category listing to broadly cover the oil and natural gas industry. In support, the Administrator has determined in this action, pursuant to CAA section 111(b)(1)(A), that the listed source category, as defined in the revision, contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. Therefore, the category listing and the Administrator's determination (to the extent they are necessary) provide authority for standards we are promulgating in this final rule, including the standards for GHG.

[64] See section IV.A of this preamble.

finding is made with respect to the source category; CAA section 111(b)(1)(A) does not provide that an endangerment finding is made as to specific pollutants. This contrasts with other CAA provisions that do require the EPA to make endangerment findings for each particular pollutant that the EPA regulates under those provisions (*e.g.,* CAA sections 202(a)(1), 211(c)(1), 231(a)(2)(A). *See American Electric Power* v. *Connecticut,* 131 S. Ct. 2527, 2539 (2011) (''the Clean Air Act directs EPA to establish emissions standards for *categories* of stationary sources that, 'in [the Administrator's] judgment,' 'caus[e], or contribut[e] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.' § 7411(b)(1)(A).'') (emphasis added).

Second, once a source category is listed, the CAA does not specify what pollutants should be the subject of standards from that source category. The statute, in CAA section 111(b)(1)(B) simply directs the EPA to propose and then promulgate regulations ''establishing Federal standards of performance for new sources within such category.'' In the absence of specific direction or enumerated criteria in the statute concerning what pollutants from a given source category should be the subject of standards, it is appropriate for the EPA to exercise its authority to adopt a reasonable interpretation of this provision. *Chevron U.S.A. Inc.* v. *NRDC,* 467 U.S. 837, 843–44 (1984).[65]

The EPA has previously interpreted this provision as granting it the discretion to determine which pollutants should be regulated. See Standards of Performance for Petroleum Refineries, 73 FR 35838, 35858 (June 24, 2008) (concluding the statute provides ''the Administrator with significant flexibility in determining which pollutants are appropriate for regulation under section 111(b)(1)(B)'' and citing cases). Further, in directing the Administrator to propose and promulgate regulations under CAA section 111(b)(1)(B), Congress provided that the Administrator should take comment and then finalize the standards with such modifications ''as [s]he deems appropriate.'' The D.C. Circuit has considered similar statutory phrasing from CAA section 231(a)(3) and concluded that ''[t]his delegation of authority is both explicit and extraordinarily broad.'' *National Assoc. of Clean Air Agencies* v. *EPA*, 489 F.3d 1221, 1229 (D.C. Cir. 2007).

In exercising its discretion with respect to which pollutants are appropriate for regulation under CAA section 111(b)(1)(B), the EPA has in the past provided a rational basis for its decisions. See *National Lime Assoc.* v. *EPA*, 627 F.2d 416, 426 & n.27 (D.C. Cir. 1980) (court discussed, but did not review, the EPA's reasons for not promulgating standards for NO_X, SO_2, and CO from lime plants); Standards of Performance for Petroleum Refineries, 73 FR 35859–60 (June 24, 2008) (providing reasons why the EPA was not promulgating GHG standards for petroleum refineries as part of that rule). Though these previous examples involved the EPA providing a rational basis for not setting standards for a given pollutant, a similar approach is appropriate where the EPA determines that it should set a standard for an additional pollutant for a source category that was previously listed and regulated for other pollutants. The EPA took this approach in setting limits for new electric generating units.[66] The EPA interprets CAA section 111(b)(1)(B) to provide authority to establish a standard for performance for any pollutant emitted by that source category as long as the EPA has a rational basis for setting a standard for the pollutant. In making such determination, we have generally considered a number of factors to help inform our decision. These include the amount of the pollutant that is being emitted from the source category, the availability of technically feasible control options, and the costs of those control options.[67]

In this rulemaking, the EPA has a rational basis for concluding that GHGs from the oil and natural gas source category, which is a large category of sources of GHG emissions, merit regulation under CAA section 111. In making this determination, the EPA focuses on methane emissions from this category. The information summarized here and discussed in other sections of this preamble provides the rational basis for the GHG standards, expressed as limitations on methane, established in this action.[68]

In 2009, the EPA made a finding that GHG air pollution may reasonably be anticipated to endanger public health or welfare under section 202(a) of the CAA [69] and, in 2010, the EPA denied petitions to reconsider that finding. The EPA extensively reviewed the available science concerning GHG pollution and its impacts in taking those actions. In 2012, the United States Court of Appeals for the District of Columbia Circuit upheld the finding and the denial of petitions to reconsider.[70] In addition, assessments released by the Intergovernmental Panel on Climate Change (IPCC), the USGCRP, and the NRC, and other organizations published after 2010 lend further credence to the validity of the 2009 Endangerment Finding. No information that commenters have presented or that the EPA has reviewed provides a basis for reaching a different conclusion for purposes of this action. Indeed, current and evolving science discussed in detail in sections IV.B and C of this preamble is confirming and enhancing our understanding of the near- and longer-term impacts that elevated concentrations of GHGs, including methane, are having on Earth's climate and the adverse public health, welfare, and economic consequences that are occurring and are projected to occur as a result.

Moreover, the high quantities of methane emissions from the oil and natural gas source category demonstrate that it is rational for the EPA to set methane limitations to regulate GHG emissions from this sector. The oil and natural gas source category is the largest emitter of methane in the United States, contributing about 29 percent of total United States methane emissions. The methane that this source category emits accounts for 3 percent of all United States GHG emissions. As shown in Tables 4 and 5 in this preamble, oil and gas sources are very large emitters of methane: In fact, GWP-weighted emissions of methane from these sources are larger than emissions of all GHGs from about 150 countries. Methane is a GHG with a global warming potential 28 to 36 times greater than that of CO_2.[71] When considered in

[65] In *Chevron,* the United States Supreme Court held that an agency must, at Step 1, determine whether Congress's intent as to the specific matter at issue is clear, and, if so, the agency must give effect to that intent. If Congressional intent is not clear, then, at Step 2, the agency has discretion to fashion an interpretation that is a reasonable construction of the statute.

[66] 80 FR 64510, 64529–30, October 23, 2015.

[67] See 80 FR 56593, 56600–09, (section VI of the proposed rule) and 56616–45, September 18, 2015 (section VIII of the proposed rule).

[68] Specifically, Sections IV.B and C, V, and VI of this final rule.

[69] 74 FR 66496 (December 15, 2009).

[70] Coalition for Responsible Regulation v. EPA, 684 F.3d 102, 119–126 (D.C. Circuit 2012).

[71] IPCC, 2013: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 1535 pp. Note that for purposes of inventories and reporting, GWP values from the 4th Assessment Report may be used. For the purposes of calculating GHG emissions, the GWP value

total, the facts presented in sections IV.B and C of this preamble, along with prior EPA analysis, including that found in the 2009 Endangerment Finding, provide a rational basis for regulating GHG emissions from affected oil and gas sources by expressing GHG limitations in the form of limits on methane emissions.

To reiterate, the ''air pollution'' defined in the 2009 Endangerment Finding is the atmospheric mix of six long-lived and directly emitted GHGs: CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6.[72] This is the same pollutant that is regulated by this rule. However, the standards of performance adopted in the present rulemaking address only one constituent gas of this air pollution: Methane. This is reasonable, given that methane is the constituent gas emitted in the largest volume by the source category and for which there are available controls that are technically feasible and cost effective. There is no requirement that standards of performance address each component of an air pollutant. Clean Air Act section 111(b)(1)(B) requires the EPA to establish ''standards of performance'' for listed source categories, and the definition of ''standard of performance'' in CAA section 111(a)(1) does not specify which air pollutants must be controlled. So, while the limitations in this rule are expressed as limits on methane, the pollutant regulated is GHGs.

Some commenters have argued that the EPA is required to make a new endangerment finding before it may set limitations for methane from the oil and natural gas source category. We disagree, for the reasons discussed above. Moreover, even if CAA section 111 required the EPA to make an endangerment finding as a prerequisite for this rulemaking, then, the information and conclusions described above in sections IV.B and C of this preamble should be considered to constitute the requisite finding (which includes a finding of endangerment as well as a cause-or-contribute significantly finding). The same facts that support our rational basis determination would support such a finding. The EPA's rational basis for regulating GHGs, by setting methane limitations, under CAA section 111 is based primarily on the analysis and conclusions in the EPA's 2009 Endangerment Finding and 2010 denial of petitions to reconsider that Finding, coupled with the subsequent assessments from the IPCC, USGCRP, and NRC that describe scientific developments since those EPA actions and other facts contained herein.

More specifically, our approach here—reflected in the information and conclusions described above—is substantially similar to that reflected in the 2009 Endangerment Finding and the 2010 denial of petitions to reconsider. The D.C. Circuit upheld that approach in *Coalition for Responsible Regulation* v. *EPA*, 684 F.3d 102, 117–123 (D.C. Cir. 2012) (noting, among other things, the ''substantial . . . body of scientific evidence marshaled by EPA in support of the Endangerment Finding'' (id. at 120); the ''substantial record evidence that anthropogenic emissions of greenhouse gases very likely caused warming of the climate over the last several decades'' (id. at 121); ''substantial scientific evidence . . . that anthropogenically induced climate change threatens both public health and public welfare . . . [through] extreme weather events, changes in air quality, increases in food- and water-borne pathogens, and increases in temperatures'' (id.); and ''substantial evidence . . . that the warming resulting from the greenhouse gas emissions could be expected to create risks to water resources and in general to coastal areas. . . .'' (id.)). The facts, unfortunately, have only grown stronger and the potential adverse consequences of GHG to public health and the environment more dire in the interim.[73] The facts also demonstrate that the current methane emissions from oil and natural gas production sources and natural gas processing and transmission sources contribute substantially to nationwide GHG emissions.

The EPA also reviewed comments presenting other scientific information to determine whether that information has any meaningful impact on our analysis and conclusions. For both the rational basis analysis and for any endangerment finding, assuming for the sake of argument that one would be necessary for this final rule, the EPA focused on public health and welfare impacts within the United States, as it did in the 2009 Endangerment Finding. The impacts in other world regions strengthen the case because impacts in other world regions can in turn adversely affect the United States and its citizens.[74]

Lastly, EPA identified technically feasible and cost effective controls that can be applied nationally to reduce methane emissions and, thus, GHG emissions, from the oil and natural gas source category.

The EPA considered whether the costs (*e.g.,* capital costs, operating costs) are reasonable considering the emission reductions achieved through application of the controls required. For a detailed discussion on how we evaluated control costs and our cost analysis for individual emission sources, please see the proposal and the final TSD in the public docket.

V. Summary of Final Standards

This section presents a summary of the specific standards we are finalizing for various types of equipment and emission points. More details of the rationale for these standards and requirements, including alternative compliance options and exemptions to the standards, are provided in sections VI, VII, and VIII of this preamble, the TSD, and the RTC document in the public docket.

A. Control of GHG and VOC Emissions in the Oil and Natural Gas Source Category—Overview

In this action, the EPA is finalizing emission standards for GHG, in the form of limitations on methane, and VOC

---

published on Table A–1 to subpart A of 40 CFR part 98 should still be used.

[72] See 74 FR 66496, 66497 (December 15, 2009).

[73] Nor does the EPA consider the cost of potential standards of performance in making this finding. Like the endangerment finding under section 202(a) at issue in State of Massachusetts v. EPA, 549 U.S. 497 (2007), the pertinent issue is a scientific inquiry as to whether an endangerment to public health or welfare from the relevant air pollution may reasonably be anticipated. Where, as here, the scientific inquiry conducted by the EPA indicates that these statutory criteria are met, the Administrator does not have discretion to decline to make a positive endangerment finding to serve other policy grounds. Id. at 532–35. In this regard, an endangerment finding is analogous to setting national ambient air quality standards under CAA section 109(b), which similarly call on the Administrator to set standards that in her ''judgment'' are ''requisite to protect the public health''. The EPA is not permitted to consider potential costs of implementation in setting these standards. Whitman v. American Trucking Assn's, 531 U.S. 457, 466 (2001); see also *Michigan* v. *EPA*, U.S. (no. 14–46, June 29, 2015) slip op. pp. 10–11 (reiterating *Whitman* holding). The EPA notes further that section 111(b)(1) contains no terms such as ''necessary and appropriate'' which could suggest (or, in some contexts, require) that costs may be considered as part of the finding. Compare CAA section 112(n)(1)(A); see *State of Michigan,* slip op. pp. 7–8. The EPA, of course, must consider costs in determining whether a best system of emission reduction is adequately demonstrated and so can form the basis for a section 111(b) standard of performance, and the EPA has carefully considered costs here and found them to be reasonable. See sections V and VI below. The EPA also has found that the rule's quantifiable benefits exceed regulatory costs under a range of assumptions were new capacity to be built. See RIA. Accordingly, this endangerment finding would be justified if (against our view) it is both required, and (again, against our view) costs are to be considered as part of the finding.

[74] See 74 FR 66514 and 66535, December 15, 2009.

emissions, for certain new, modified and reconstructed emission sources across the oil and natural gas source category at subpart OOOOa. For some of these sources, there are VOC requirements currently in place that were established in the 2012 NSPS, and we are now establishing GHG limitations for those emission points. For others, for which there are no current requirements, we are finalizing both GHG and VOC standards. We are also finalizing improvements to enhance implementation of the current standards at subpart OOOO. For the reasons explained in the previous section, the EPA believes that GHG standards, in the form of limitations on methane, are warranted, even for those already subject to VOC standards under the 2012 NSPS. Further, as shown in the final TSD, there are cost effective controls that achieve simultaneous reductions of GHG and VOC emissions.

Pursuant to CAA section 111(b), we are both amending subpart OOOO and adding a new subpart, OOOOa. We are amending subpart OOOO, which applies to facilities constructed, modified or reconstructed after August 23, 2011, (*i.e.,* the original proposal date of subpart OOOO) and on or before September 18, 2015 (*i.e.,* the proposal date of the new subpart OOOOa), and is amended only to include the revisions reflecting implementation improvements in response to issues raised in petitions for reconsideration. We are adding subpart OOOOa, which will apply to facilities constructed, modified or reconstructed after September 18, 2015, to include current VOC requirements already provided in subpart OOOO (as updated) as well as new provisions for GHGs and VOCs across the oil and natural gas source category as highlighted below in this section.

As the purpose of this action is to control and limit emissions of GHG and VOC, EPA seeks to confirm that all regulatory standards are met. Any owner or operator claiming technical infeasibility, nonapplicability, or exemption from the regulation has the burden to demonstrate the claim is reasonable based on the relevant information. In any subsequent review of a technical infeasibility or nonapplicability determination, or a claimed exemption, EPA will independently assess the basis for the claim to ensure flaring is limited and emissions are minimized, in compliance with the rule. Well-designed rules ensure fairness among industry competitors and are essential to the success of future enforcement efforts.

B. Centrifugal Compressors

We are finalizing amendments to the 2012 NSPS, and adding new requirements to establish both VOC and GHG standards (in the form of limitations on methane emissions) for new, modified or reconstructed wet seal centrifugal compressors located across the oil and natural gas source category. Specifically, the final rule adds GHG standards to the current VOC standards for wet seal centrifugal compressors, as well as establishing GHG and VOC standards for those that are currently unregulated, with one exception. We are not establishing requirements for centrifugal compressors at well sites. As finalized, the standards require a 95 percent reduction of the emissions from each wet seal centrifugal compressor affected facility. The standard can be achieved by capturing and routing the emissions, using a cover and closed vent system, to a control device that achieves an emission reduction of 95 percent, or routing to a process.

C. Reciprocating Compressors

We are finalizing amendments to the 2012 NSPS and adding new requirements to establish both VOC and GHG standards (in the form of limitations on methane emissions) for new, modified, or reconstructed reciprocating compressors located across the oil and natural gas source category. Specifically, the final rule adds GHG standards to the current VOC standards for reciprocating compressors, as well as establishing GHG and VOC standards for those that are currently unregulated, with one exception. We are not establishing requirements for reciprocating compressors at well sites. The standards, which are operational standards, require either replacement of the rod packing based on usage or routing of rod packing emissions to a process via a closed vent system under negative pressure. The owner or operator of a reciprocating compressor affected facility is required to monitor the duration (in hours) that the compressor is operated, beginning on the date of initial startup of the reciprocating compressor affected facility. On or before 26,000 hours of operation, the owner or operator is required to change the rod packing. Owners or operators can elect to change the rod packing every 36 months in lieu of monitoring compressor operating hours. As an alternative to rod packing replacement, owners and operators may route the rod packing emissions to a process via a closed vent system operated at negative pressure.

D. Pneumatic Controllers

We are finalizing amendments to the 2012 NSPS and adding new requirements to establish both VOC and GHG standards (in the form of limitations on methane emissions) for new, modified, or reconstructed pneumatic controllers located across the oil and natural gas source category. Specifically, the final rule adds GHG standards to the current VOC standards for pneumatic controllers and establishes GHG and VOC standards for those that are currently unregulated. We are finalizing GHG (in the form of limitations on methane emissions) and VOC standards to control emissions by requiring use of low-bleed controllers in place of high-bleed controllers (*i.e.,* natural gas bleed rate not to exceed 6 standard cubic feet per hour (scfh)) at all locations within the source category except for natural gas processing plants. For natural gas processing plants, we are finalizing standards to control GHG and VOC emissions by requiring that pneumatic controllers have a zero natural gas bleed rate (*i.e.,* they are operated by means other than natural gas, such as being driven by compressed instrument air). These standards apply to each newly installed, modified or reconstructed pneumatic controller (including replacement of an existing controller). The finalized standards provide exemptions for certain critical applications based on functional considerations.

E. Pneumatic Pumps

We are finalizing standards for natural gas-driven diaphragm pumps.[75] The standards require that GHGs (in the form of limitations on methane emissions) and VOC emissions from new, modified and reconstructed natural gas-driven diaphragm pumps located at well sites be reduced by 95 percent if either a control device or the ability to route to a process is already available onsite, unless it is technically infeasible at sites other than new developments (*i.e.*, greenfield sites). In setting this requirement, the EPA recognizes that there may not be a control device or process available onsite. Our analysis shows that it is not cost-effective to require the owner or operator of a pneumatic pump affected facility to install a new control device or process onsite to capture emissions. If a control device or ability to route to a process is not available onsite, the pneumatic pump affected facility is not

[75] A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump. For more details, please see section VI.

subject to the emission reduction provisions of the final rule. In other instances, there may be a control device available onsite, but it may not be capable of achieving a 95 percent reduction. In those cases, we are not requiring the owner or operator to install a new control device onsite or to retrofit the existing control device, however, we are requiring the owner or operator of a pneumatic pump affected facility at a well site to route the emissions to an existing control device even it if achieves a level of emissions reduction less than 95 percent. In those instances, the owner or operator must maintain records demonstrating the percentage reduction that the control device is designed to achieve. In this way, the final rule will achieve emission reductions with regard to pneumatic pump affected facilities even if the only available control device cannot achieve a 95 percent reduction. For pneumatic pumps located at natural gas processing plants, the standards require that GHG and VOC emissions from natural gas-driven diaphragm pumps be zero.

F. Well Completions

We are finalizing GHG standards (in the form of limiting methane emissions) for well completions of hydraulically fractured (or refractured) gas wells as well as GHG and VOC standards for well completions of hydraulically fractured (or refractured) oil wells. As explained in the proposal preamble, the BSER for these emission reductions are the same as the BSER for reducing VOC emissions from hydraulically fractured gas wells. Therefore, the operational standards finalized in this action are essentially the same as the VOC standards for hydraulically fractured gas wells promulgated in the 2012 NSPS. For the reason stated above, the well completion standards in this final rule apply to both gas and oil well completions.

As with gas wells, for well completions of hydraulically fractured (or refractured) oil wells, we identified two subcategories of hydraulically fractured wells for which well completions are conducted: (1) Non-wildcat and non-delineation wells (subcategory 1 wells); and (2) wildcat and delineation wells (subcategory 2 wells). A wildcat well, also referred to as an exploratory well, is a well drilled outside known fields or is the first well drilled in an oil or gas field where no other oil and gas production exists. A delineation well is a well drilled to determine the boundary of a field or producing reservoir.

We are finalizing operational standards for subcategory 1 wells that require a combination of reduced emissions completion (REC) and combustion. Compared to combustion alone, the combination of REC and combustion will maximize gas recovery and minimize venting to the atmosphere. The finalized standards for subcategory 2 wells require combustion.

For subcategory 1 wells, we define the flowback period of a well completion as consisting of two distinct stages, the ''initial flowback stage'' and the ''separation flowback stage.'' The initial flowback stage begins with the onset of flowback and ends when the flowback is routed to a separator. Routing of the flowback to a separator is required as soon as a separator is able to function (*i.e.*, the operator must route the flowback to a separator unless it is technically infeasible for a separator to function). Any gas in the flowback prior to the point at which a separator begins functioning is not subject to control. The point at which the separator can function marks the beginning of the separation flowback stage. During this stage, the operator must do the following, unless technically infeasible to do so as discussed below: (1) Route all salable quality gas from the separator to a gas flow line or collection system; (2) re-inject the gas into the well or another well; (3) use the gas as an onsite fuel source; or (4) use the gas for another useful purpose that a purchased fuel or raw material would serve. If the operator assesses all four options for use of recovered gas, and still finds it technically infeasible to route the gas as described, the operator must route the gas to a completion combustion device with a continuous pilot flame and document the technical infeasibility assessment according to § 60.5420a(c) of this final rule, which describes the specific types of information required to document that the operator has exercised due diligence in making the assessment. No direct venting of gas is allowed during the separation flowback stage unless combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways. The separation flowback stage ends when the well is shut in and the flowback equipment is permanently disconnected from the well or on startup of production. This also marks the end of the flowback period.

The operator has a general duty to safely maximize resource recovery and minimize releases to the atmosphere over the duration of the flowback period. For subcategory 1 wells (except for low gas to oil ratio (GOR) and low pressure wells discussed below), the operator is required to have a separator onsite during the entirety of the flowback period. The operator is also required to document the stages of the completion operation by maintaining records of (1) the date and time of the onset of flowback; (2) the date and time of each attempt to route flowback to the separator; (3) the date and time of each occurrence in which the operator reverted to the initial flowback stage; (4) the date and time of well shut in; and (5) the date and time that temporary flowback equipment is disconnected. In addition, the operator must document the total duration of venting, combustion and flaring over the flowback period. All flowback liquids during the initial flowback period and the separation flowback period must be routed to a well completion vessel, a storage vessel or a collection system. Because the BSER for oil wells and gas wells are the same, the final rule applies these requirements to both oil and gas wells.

For subcategory 2 wells, we are finalizing an operational standard that requires either (1) routing all flowback directly to a completion combustion device with a continuous pilot flame (which can include a pit flare) or, at the option of the operator, (2) routing the flowback to a well completion vessel and sending the flowback to a separator as soon as a separator will function and then directing the separated gas to a completion combustion device with a continuous pilot flame. For option 2, any gas in the flowback prior to the point when the separator will function is not subject to control. In either case, combustion is not required if combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways. Operators are required to maintain the same records described above for category 1 wells.

As with gas wells, we similarly recognize the limitation of ''low pressure'' oil wells from conducting REC. Therefore, consistent with the 2012 NSPS, low pressure wells are affected facilities and have the same requirements as subcategory 2 wells (wildcat and delineation wells). We have revised the definition of a ''low pressure'' well in response to comment.

Further, wells with a GOR of less than 300 scf of gas per stock tank barrel of oil produced are affected facilities, but have no well completion requirements, providing the owner or operator maintains records of the low GOR certification and a claim signed by the certifying official.

We are also retaining the provision from the 2012 NSPS, now at § 60.5365a(a)(1), that a well that is refractured, and for which the well completion operation is conducted according to the requirements of § 60.5375a(a)(1) through (4), is not considered a modified well and, therefore, does not become an affected facility for purposes of the well completion standards. We point out that such an exclusion of a ''well'' from applicability under the NSPS has no effect on the affected facility status of the ''well site'' for purposes of the fugitive emissions standards at § 60.5397a.

G. Fugitive Emissions From Well Sites and Compressor Stations

We are finalizing standards to control GHGs (in the form of limitations on methane emissions) and VOC emissions from fugitive emission components at well sites and compressor stations. Specifically, we are finalizing semiannual monitoring and repair of fugitive emission components at well sites and quarterly monitoring and repair at compressor stations. Monitoring of the components must be conducted using optical gas imaging (OGI), and repairs must be made if any visible emissions are observed. Method 21 may be used as an alternative monitoring method at a repair threshold level at 500 parts per million (ppm). Repairs must be made within 30 days of finding fugitive emissions and a resurvey of the repaired component must be made within 30 days of the repair using OGI or Method 21 at a repair threshold of 500 ppm. A monitoring plan that covers the collection of fugitive emissions components at well sites or compressor stations within a company-defined area must be developed and implemented.

H. Equipment Leaks at Natural Gas Processing Plants

We are finalizing standards to control GHGs (in the form of limitations on methane emissions) from equipment leaks at new, modified or reconstructed natural gas processing plants. These requirements are the same as the VOCs equipment leak requirements in the 2012 NSPS and require the level of control established in NSPS part 60, subpart VVa, including a detection level of 500 ppm for certain pieces of equipment, as in the 2012 NSPS. As with VOC reduction, we believe that subpart VVa level of control reflects the best system of emission reductions for reducing methane emissions.

I. Liquids Unloading Operations

The EPA stated in the proposal that we did not have sufficient information to propose a national standard for liquids unloading.[76] However, the EPA requested comment on nationally applicable technologies and techniques that reduce GHG and VOC emissions from these events. Although the EPA received valuable information from the public comment process, the information was not sufficient to finalize a national standard representing BSER for liquids unloading.

Specifically, we requested data and information on the level of GHG and VOC emissions per unloading event, the number of unloading events per year, and the number of wells that perform liquids unloading. In addition, we requested comment on (1) characteristics of the well that play a role in the frequency of liquids unloading events and the level of emissions; (2) demonstrated techniques to reduce the emissions from liquids unloading events, including the use of smart automation and the effectiveness and cost of these techniques; (3) whether there are demonstrated techniques that can be employed on new wells that will reduce the emissions from liquids unloading events in the future; and (4) whether emissions from liquids unloading can be captured and routed to a control device and whether this has been demonstrated in practice.

The EPA received some information pertaining to our request for information. Specifically, the EPA received information on the frequency of unloading and on techniques to reduce emissions through capture or flaring and learned of some operators that have been able to achieve capture in practice. While we have gained better understanding of the practice of liquids unloading, the EPA did not receive the necessary information to identify an emission reduction technology that can be applied across the category of sources. We also considered the possibility of subcategorization. However, according to the information received, the differences in liquids unloading events (with respect to both frequency and emission level) are not due to differences in well size or type of wells at which liquids unloading is performed, but rather the specific conditions of a given well at the time the operator determines that well production is impaired such that unloading must be done. Operators select the technique to perform liquids unloading operations based on the conditions of the well each time production is impaired. Because well conditions change over time, each iteration of unloading may require repeating a single technique or attempting a different technique that may not have been appropriate under prior conditions. Given the differences in conditions at different wells when liquids unloading must be performed, the EPA did not receive information about techniques, individually or as a group, that helped us to identify a BSER under our CAA section 111(b) authority. The EPA continues to search for better means to address emissions associated with liquids unloading and is including this emissions source in the upcoming information gathering effort.[77] Please refer to the RTC for additional discussion on liquids unloading.[78]

J. Recordkeeping and Reporting

We are finalizing recordkeeping and reporting requirements that are consistent with those in the current NSPS. The final rule requires owners or operators to submit initial notifications and annual reports, in addition to retaining records to assist in documenting that they are complying with the provisions of the NSPS.

For new, modified, or reconstructed pneumatic controllers, owners and operators are not required to submit an initial notification for each piece of equipment; rather, they must report the installation of these affected facilities in their first annual report following the compliance period during which they were installed. Owners or operators of well affected facilities (consistent with current requirements for gas well affected facilities) are required to submit an initial notification no later than two days prior to the commencement of each well completion operation. This notification must include contact information for the owner or operator, the United States Well Number (formerly the American Petroleum Institute (API) well number), the latitude and longitude coordinates for each well, and the planned date of the beginning of flowback.

In addition, initial annual reports are due no later than 90 days after the end of the initial compliance period, which is established in the rule. Subsequent annual reports are due no later than the same date each year as the initial annual report. The annual reports include information on all affected facilities that were constructed, modified or reconstructed during the previous year. A single report may be submitted covering multiple affected facilities,

[76] *See* 80 FR 56614 and 80 FR 56644, September 18, 2015.

[77] *See* section III.E of this preamble for a discussion of the upcoming information gathering effort.

[78] *See* RTC document in EPA Docket ID No. EPA–HQ–OAR–2010–0505.

provided that the report contains all the information required by § 60.5420a(b). This information includes general information on the company (*e.g.*, company name), as well as information specific to individual affected facilities, such as the well ID associated with the affected facility (*e.g.*, storage vessels) and the facility site name (*e.g.*, ''Compressor Station XYZ'' or ''Tank Battery 123'') and the address of the affected facility.

For well affected facilities, the information required in the annual report includes the location of the well, the United States well number, the date and time of the onset of flowback following hydraulic fracturing or refracturing, the date and time of each attempt to direct flowback to a separator, the date and time of each occurrence of returning to the initial flowback stage, and the date and time that the well was shut in and the flowback equipment was permanently disconnected or the startup of production, the duration of flowback, the duration of recovery to the flow line, duration of the recovery of gas for another useful purpose, duration of combustion, duration of venting, and specific reasons for venting in lieu of capture or combustion. For each well for which a technical infeasibility exemption is claimed, to route the recovered gas to any of the four options specified in § 60.5375a(a)(1)(ii), the report includes the reasons for the claim of technical infeasibility with respect to all four options provided in that subparagraph.

For each well for which an exemption is claimed the owner or operator must maintain records of the low GOR certification and submit a claim signed by the certifying official in the annual report. For each well for which an exemption is claimed for conditions in which combustion may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways, the report should include the location of the well, the United States Well Number, the specific exception claimed, the starting date and ending date for the period the well operated under the exception, and an explanation of why the well meets the claimed exception. The annual report must also include records of deviations where well completions were not conducted according to the applicable standards.

For centrifugal compressor affected facilities, information in the annual report must include an identification of each centrifugal compressor using a wet seal system constructed, modified or reconstructed during the reporting period, as well as records of deviations in cases where the centrifugal compressor was not operated in compliance with the applicable standards.

For reciprocating compressors, information in the annual report must include the cumulative number of hours of operation or the number of months since initial startup or the previous reciprocating compressor rod packing replacement, whichever is later, or a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

Information in the annual report for pneumatic controller affected facilities includes location and documentation of manufacturer specifications of the natural gas bleed rate of each pneumatic controller installed during the reporting period. For pneumatic controllers for which the owner is claiming an exemption from the standards, the annual report includes documentation that the use of a pneumatic controller with a natural gas bleed rate greater than 6 scfh is required and the reasons why. The annual report also includes records of deviations from the applicable standards.

For pneumatic pump affected facilities, information in the annual report includes an identification of each pneumatic pump constructed, modified or reconstructed during the compliance period; if applicable, a certification that no control was available onsite and that there is no ability to route to a process; an identification of any sites that contain pneumatic pumps and installed a control device during the reporting period, where there was previously no control device or ability to route to a process at a site; and records of deviations in cases where the pneumatic pump was not operated in compliance with the applicable standards.

The final rule includes new requirements for monitoring and repairing sources of fugitive emissions at well sites and compressor stations. An owner or operator must submit an annual report, which covers the collection of fugitive emissions components at well sites and compressor stations within an area defined by the company. The report must include the date and time of the surveys completed during the reporting year, the name of the operator performing the survey; the ambient temperature, sky conditions, and maximum wind during the survey; the type of monitoring instrument used; the number and type of components that were found to have fugitive emissions; the number and type of components that were not repaired during the monitoring survey; the number and type of difficult-to-monitor and unsafe-to-monitor components that were monitored; the date of the successful repair of the fugitive emissions component if it was not repaired during the survey; the number and type of fugitive emission components that were placed on delay of repair and the explanation of why the component could not be repaired and was placed on delay of repair; and the type of monitoring instrument used to resurvey a repaired component that could not be repaired during the initial monitoring survey. If an owner or operator chooses to use Method 21 to conduct the monitoring survey, they are required to keep records that include the type of monitoring instrument used and the fugitive emissions component identification. The owner or operator is required to keep a log for each affected facility. The log must include the date the monitoring survey was performed, the technology used to perform the survey, the number and types of equipment found to have fugitive emissions, a digital photograph or video of the monitoring survey when an OGI instrument is used to perform the monitoring survey, the date or dates of first attempt to repair the source of fugitive emissions, the date of repair of each source of fugitive emissions that could not be repaired during the initial monitoring survey, any source of fugitive emissions found to be technically infeasible or unsafe to repair and an explanation of why the component was placed on delay of repair, a list of the fugitive emissions components that were tagged as a result of not being repaired during the initial monitoring survey, and a digital photograph or video of each untagged fugitive emissions component that could not be repaired during the monitoring survey when the fugitive emissions were initially found. These digital photographs and logs must be available at the affected facility or the field office.

Consistent with the current requirements of subpart OOOO, records must be retained for 5 years and generally consist of the same information required in the initial notification and annual reports. The records may be maintained either onsite or at the nearest field office.

K. Reconsideration Issues Being Addressed

The EPA is finalizing numerous items in subpart OOOO on which we granted reconsideration and proposed changes with some further adjustments as a result of public comment. To the extent that these items relate to subpart OOOOa, we are also finalizing the same provisions for purposes of consistency between the two rules. First, we are finalizing corrections to the storage vessel control device monitoring and testing provisions related to in-field performance testing of enclosed combustors, initial and ongoing performance testing for any enclosed combustors used to comply with the emissions standard for an affected facility, and consistent requirements for monitoring of visible emissions for all enclosed combustion units. We are also finalizing clarified applicability requirements for storage vessel affected facilities. Next, we are finalizing amendments to include initial compliance requirements for bypass devices and certain closed vent systems and provide an alternative in subpart OOOO. Specifically, the rule allows for either an alarm at the bypass device or a remote alarm. The EPA is not finalizing our proposal to require both forms of alarm under subpart OOOO to avoid retroactive requirements.

Additionally, the EPA is finalizing recordkeeping requirements for repair logs for control devices failing a visible emissions test. We are clarifying the due date for the initial annual report and finalizing that flares used to comply with subpart OOOO are subject to the design and operation requirements in the general provisions. Next, we clarify that the monitoring provisions of subpart VVa applicable to affected units of subpart OOOO do not extend to open-ended valves or lines. We are finalizing clarification to the initial compliance requirement specifically to identify that the 2012 rule already includes a provision similar to subpart KKK. The EPA is finalizing the exemption from the notification required for reconstruction to affected facility pneumatic controllers, centrifugal compressors, and storage vessels in subpart OOOOa. The EPA is finalizing provisions for management of waste from spent carbon canisters. The EPA is finalizing a definition of the term ''capital expenditure'' in subpart OOOO. The EPA is finalizing an exemption for certain water recycling vessels that EPA did not intend to be affected facility storage vessels under subparts OOOO or OOOOa. By exempting such vessels, EPA will address a disincentive for recycling of water for hydraulic fracturing. Lastly, the EPA is not finalizing continuous control device monitoring requirements for storage vessels and centrifugal compressor affected facilities in subpart OOOO. For additional discussion of these issues, please refer to section VI of this preamble and the RTC.

L. Technical Corrections and Clarifications

We discovered 22 drafting errors in the proposal and have corrected these errors in the final rule. Please see section VI for a complete list of technical corrections and clarifications.

M. Prevention of Significant Deterioration and Title V Permitting

In the proposed rule, we stated that the pollutant we were proposing to regulate was GHGs, not methane as a separately regulated pollutant. 80 FR 56593, 56600–01 (Sept. 18, 2015). As explained in section VII of this preamble, we are adding provisions to the final rule, analogous to what was included in Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 FR 64509 (Oct. 23 2015), to make clear in the regulatory text that the pollutant regulated by this rule is GHGs.

N. Final Standards Reflecting Next Generation Compliance and Rule Effectiveness

In making decisions on the final requirements for this rule, we have emphasized the value of requirements that reflect principles of Next Generation Compliance and Rule Effectiveness. EPA's Next Generation Compliance strategy includes designing rules that promote improved compliance and better environmental outcomes. Specifically, we are finalizing standards with the following Next Generation Compliance strategies: (1) Electronic reporting via the EPA's Central Data Exchange (CDX), (2) clear applicability criteria (*e.g.*, modification criteria), (3) incentives for intrinsically lower emitting equipment (*e.g.*, solar pumps at gas plants are not affected facilities), (4) OGI technology for monitoring fugitive emissions, (5) digital picture reporting as an alternative for well completions (''REC PIX'') and manufacturer installed control devices, (6) qualified professional engineer certification of technical infeasibility to connect a pneumatic pump to an existing control device, and (7) qualified professional engineer certification of closed vent system design. These requirements, or options for compliance, provide opportunities for owners and operators to reduce obligations by making particular choices, reduce the burden for both the regulated industry and the agencies providing oversight, and provide greater transparency for all parties, including the public.

VI. Significant Changes Since Proposal

This section identifies significant changes in this rule from the proposed rule. These changes reflect the EPA's consideration of over 900,000 comments submitted on the proposal and other information received since the proposal, while preserving the aims underlying the proposal. The final rule protects human health and the environment by improving the existing NSPS and adding emission reduction standards for additional significant sources of GHGs and VOCs, consistent with the CAA. The EPA sought to achieve this important goal by endeavoring, where possible, to consistently expand the 2012 NSPS requirements across the oil and natural gas sector while also accounting for the unique characteristics of each type of source in setting emission reduction requirements. In this section, we discuss the significant changes since proposal by source category and the broad background for those changes. More specific information regarding comments and our responses appears in section VIII and in materials available in the docket.

A. Centrifugal Compressors

For centrifugal compressors, comments and information available led us to finalize the standards as proposed. In the proposed rule, we proposed to require 95 percent reduction of emissions from each centrifugal compressor affected facility. The standard can be achieved by capturing and routing the emissions using a cover and closed vent system to a control device (*i.e.*, combustion control device) that achieves an emission reduction of 95 percent, or by routing the captured emissions to a process. For additional details, please refer to section VIII, the TSD, and the RTC supporting documentation in the public docket.

B. Reciprocating Compressors

For the reciprocating compressors requirements, we are finalizing the standards as proposed, except with a slight modification to the definition of reciprocating compressor rod packing. In the proposed rule, we proposed to require replacement of rod packing on or before 26,000 hours or 3 years of operation, or alternatively to route emissions via a closed vent system under negative pressure. To account for segments of the industry in which reciprocating compressors operate in a pressurized mode for a fraction of the calendar year, the standard is based on the determination that 26,000 hours of operation are comparable to 3 years of continuous operation.

In the final rule, we revised the definition of reciprocating compressor rod packing. The EPA received comment that the definition of rod packing should be included in the rule to clarify the intent to replace any component of the rod packing that was contributing to emissions from the rod packing assembly. Because we agree that this clarification is useful, we have revised the definition of reciprocating compressor rod packing in the final rule to mean 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 from the compressor, or any other mechanism that provides the same function of limiting the amount of compressed natural gas that escapes from the compressor. For additional details, please refer to section VIII, the TSD, and the RTC supporting documentation in the public docket.

C. Pneumatic Controllers

For pneumatic controllers, comments and information available led us to finalize the standards as proposed. We proposed to require the use of low-bleed controllers in place of high-bleed controllers (*i.e.,* natural gas bleed rate not to exceed 6 scfh) [79] at all locations within the source category, except for natural gas processing plants. For natural gas processing plants, the standards require control of GHG and VOC emissions by requiring that pneumatic controllers have a zero natural gas bleed rate (*i.e.,* they are operated by means other than natural gas, such as being driven by compressed instrument air).

The final rule provides that certain pneumatic controllers, reflecting the particular functions they perform, have only tagging and recordkeeping and reporting requirements. As discussed in the proposal, the EPA identified situations where high-bleed controllers (*i.e.,* controllers with a natural gas bleed rate greater than 6 scfh) are necessary because of functional requirements, such as positive actuation or rapid actuation. An example would be controllers used on large emergency shutdown valves on pipelines entering or exiting compressor stations. The 2012 NSPS accounts for this by providing an exemption to pneumatic controllers for which compliance would pose a functional limitation due to their actuation response time or other operating characteristics. The EPA is finalizing the same exemption for all pneumatic controllers across the source category. For additional details, please refer to section VIII, the TSD, and the RTC supporting documentation in the public docket.

[79] Low-bleed controllers are not affected facilities under this final rule.

D. Pneumatic Pumps

In the final rule, the EPA is finalizing requirements for pneumatic pumps that use control devices or processes that are already available onsite. At natural gas processing plants, the EPA proposed to require reductions of 100 percent of GHG (in the form of methane) and VOC emissions from all diaphragm pneumatic pumps. For locations other than natural gas processing plants, the EPA proposed to require reductions of 95 percent of GHG (in the form of methane) and VOC emissions from all natural gas-driven diaphragm pumps, if an existing control or process was available.

The public comment process helped us to identify aspects of the proposed requirements that may not be practical or feasible in all cases, and commenters submitted additional information for us to analyze. In this final rule, based on our consideration of the comments received and other relevant information, we have made certain changes to the proposed standards for pneumatic pumps. The final standards require the GHG (in the form of a limitation on methane) and VOC emissions from new, modified, or reconstructed natural gas-driven diaphragm pumps located at well sites to be routed to an available control device or process onsite, unless such routing is technically infeasible at non-greenfield sites. We are not finalizing a technical infeasibility exemption at greenfield sites, where circumstances that could otherwise make control of a pneumatic pump technically infeasible at an existing location can be addressed in the site's design and construction. For pneumatic pumps located at a natural gas processing plant, the final rule requires the GHG (in the form of a limitation on methane) and VOC emissions from natural gas-driven diaphragm pumps to be zero.

While we acknowledge that solar-powered, electrically-powered, and air-driven pumps cannot be employed in all applications, we encourage operators to use pumps other than natural gas-driven pneumatic pumps where their use is technically feasible. To incentivize the use of these alternatives, the final rule's definition of ''pneumatic pump affected facility'' described in § 60.5365a(h) only includes natural gas-driven pumps. Pumps that are driven by means other than natural gas are not affected facilities subject to the pneumatic pump provisions of the NSPS and are not subject to any requirements under the final rule.

Provided below are the significant changes since proposal that result from the information in the record and the comments that we received and our rationale for these changes. For additional details, please refer to section VIII, the TSD, and the RTC supporting documentation in the public docket.

1. Piston Pumps

The EPA received several comments concerning the level of GHG and VOC emissions from natural gas-driven pneumatic piston pumps. The comments focused on the small volume of gas discharged by these pumps and the intermittent nature of their use. Other commenters suggested that the EPA treat pneumatic pumps consistently with pneumatic controllers. The commenters state that the same bleed rate considerations should be applied to pneumatic pumps because they are similar devices. Other commenters discussed the technical infeasibility of controlling emissions from piston pumps due to the inability to move such a small and intermittent gas flow through a duct or pipe to a control device.

We agree with commenters that pneumatic controller bleed rate considerations can serve as a useful guide in considering emission reduction requirements for pneumatic pumps. In response to these comments, we further evaluated the natural gas flow rate of pneumatic pumps and agree that piston pumps are inherently low-emitting because of their small size, design, and usage patterns. As discussed in the TSD to the proposed rule, we used natural gas emission rates between 2.2 to 2.5 scf/hr during operation of piston pumps. We determined these emission rates based on a joint report from the EPA and the Gas Research Institute on methane emissions from the natural gas industry. Our analysis of the currently available data, the information in the record, and consideration of public comments lead us to the conclusion that we should exclude piston pumps from coverage under the NSPS based on their inherently low emission rates. This approach is consistent with the manner in which we addressed low-bleed pneumatic controllers. After considering the inherently low emission rates of low-bleed pneumatic controllers, we determined that they should not be subject to the final rule requirements. Similarly, based upon the information that we have on the low emission rates of piston pumps, we are not establishing requirements for them in this final rule.

We note that our best available emissions data for diaphragm pumps, as discussed in the TSD, indicates that the emission rate ranges from about 20 to 22 scf/hr during operation of a diaphragm pump. Based on our analysis of this data, we do not believe exclusion of diaphragm pumps from the definition of a pneumatic pump affected facility is warranted. As a result, we are retaining requirements for diaphragm pumps in the final rule.

2. Pneumatic Pumps Located in the Gathering and Boosting and Transmission and Storage Segments

We received comment that pneumatic pumps located in the transmission and storage segment generally have very low emissions. Similar to the arguments presented above for piston pumps, commenters contend that these low emission rate pumps should not be subjected to the final rule. In response to these comments, we reviewed our available information used in the proposed rule TSD to estimate the number of pneumatic pumps and the emission rates of these pumps in all segments of the oil and natural gas sector. In the TSD for the final rule, we noted that neither the GHGRP nor the GHG Inventory include data about pneumatic pumps or their emission rates in the natural gas transmission and storage segment. Because we currently have no reliable source of information indicating the prevalence of use of pneumatic pumps in this segment, nor what their emission rates would be if they are used, we are not finalizing pneumatic pump requirements for the transmission and storage segment at this time.

We also reviewed the available GHGRP and GHG Inventory data for pneumatic pumps, which was limited to the production segment. We consider the production segment to include both well sites and the gathering and boosting segment. Our available data indicate that pneumatic pumps are used at well sites as well as emission data for those pumps, but are silent on the prevalence of use of pneumatic pumps in the gathering and boosting segment, and what their emission rates would be if they are used. As with pneumatic pumps in the transmission and storage segment, we are not finalizing pneumatic pump requirements for the gathering and boosting segments at this time because of the lack of information in the record to support finalizing requirements for these pumps.

We note that the EPA is currently conducting a formal process to gather additional data on existing sources in the oil and natural gas sector. We believe that this data collection effort will provide additional information on the use and emissions of pneumatic pumps in the transmission and storage segment and gathering and boosting segment. Once we have obtained and analyzed these data, we will be better equipped to determine whether regulation of pneumatic pumps in the transmission and storage segment and gathering and boosting segment is warranted. See section III.E for more detail regarding the EPA's information collection request for existing sources.

3. Technical Infeasibility

We agree with comments that there may be circumstances, such as insufficient pressure or control device capacity, where it is technically infeasible to capture and route pneumatic pump emissions to a control device or process, and we have made changes in the final rule to include an exemption for these instances. The owner or operator must maintain records of an engineering evaluation and certification providing the basis for the determination that it is technically infeasible to meet the rule requirements. The rule does not allow the operator to claim the technical infeasibility exemption for a pneumatic pump affected facility at a greenfield site (defined as a site, other than a natural gas processing plant, which is entirely new construction), where circumstances that could otherwise make control of a pneumatic pump technically infeasible at an existing location can be addressed in the site's design and construction.

4. Efficiency of Existing Control Devices

As noted above, we are finalizing emission standards for new, modified, and reconstructed natural gas-driven diaphragm pumps located at well sites requiring emissions be reduced by 95 percent if either a control device or the ability to route to a process is already available onsite. In setting this requirement, the EPA recognizes that there may not be a control device or process available onsite. Our analysis shows that it is not cost-effective to require the owner or operator of a pneumatic pump affected facility to install a new control device or process onsite to capture emissions. In those instances, the pneumatic pump affected facility is not subject to the emission reduction provisions of the final rule.

Commenters have also raised concerns, and we agree, that the control device available onsite may not be able to achieve a 95 percent emission reduction. We evaluated whether this requirement should only be triggered when a NSPS subpart OOOO or OOOOa compliant control device was onsite, which would alleviate the control efficiency concern raised by commenters. However, the EPA is concerned that significant emissions reductions would be lost as a result of limiting the required type of equipment that must be used to control pneumatic pump emissions to only those that are designed to achieve 95 percent emission reductions. We are not requiring the owner or operator to install a new control device on site that is capable of meeting a 95 percent reduction nor are we requiring that the existing control device be retrofitted to enable it to meet the 95 percent reduction requirement. However, we are requiring that the owner or operator of a pneumatic pump affected facility at well sites to route the emissions to an existing control device even if it achieves a level of emissions reduction less than 95 percent. In those instances, the owner or operator must maintain records demonstrating the percentage reduction that the control device is designed to achieve. In this way, the final rule will achieve emission reductions with regard to pneumatic pump affected facilities even if the only available control device on site cannot achieve a 95 percent reduction.

5. Compliance Requirements

In response to concerns about applicability of subpart OOOO or OOOOa compliance requirements, the EPA has clarified our intent in the final rule that existing control devices that are not already subject to subparts OOOO or OOOOa compliance requirements (*i.e.,* control devices that are subject to other federal or state compliance requirements) are not subject to the performance specifications, performance testing, and monitoring requirements in this rule solely because they are controlling pneumatic pump emissions. We believe that control devices covered by other federal, state, or other regulations would be subject to compliance requirements under those provisions and, therefore, we have reasonable assurance that the devices will perform adequately, and we do not need to include existing controls that are not already covered by subparts OOOO and OOOOa under the compliance requirements for these subparts.

6. Cost Analysis

In response to commenters' concerns that the costs were underestimated for compliance with the pneumatic pump requirements, we revised the cost analysis using the average of our annualized costs and two additional annualized cost estimates provided by commenters.[80] Commenters' cost estimate methodologies and inputs varied from EPA's cost estimate which prevented us from conducting a side-by-side comparison with our cost estimate, nor could we directly compare the commenters' estimates with one another. However, in order to take into account the cost estimates provided by the commenters, we revised our cost analysis using the average of our annualized costs and the two additional annualized cost estimates provided by commenters. This is the same approach we would have taken had we obtained cost quotes from three separate vendors to install the closed vent system, and which we believe is the most equitable procedure when there is insufficient information to distinguish between the three cost estimates. One commenter gave an estimated capital cost of $5,800 which is annualized to be $826. A second commenter gave an estimated capital cost of $8,500 which annualized to be $1,210. The proposed capital cost to route emissions through a closed vent system was $2,000 which when annualized is $285. Based on our revised cost analysis, the capital cost for routing the emissions to an existing control device or process is $5,433, and the annualized cost is $774. We more fully discuss our cost estimate analysis in the TSD.

We evaluated the cost of control for routing emissions to an existing combustion device or process where we assign the cost equally to methane and VOC. For diaphragm pumps at well sites, the cost of reducing methane emissions is $235 per ton and the cost of reducing VOC emissions is $847 per ton, using the single-pollutant approach. Based on this revised cost analysis using additional cost information, we find that the cost of control for reducing methane emissions remains reasonable.

7. Affected Facility Definition

The EPA received comment that there was contradictory language in the proposal preamble and regulatory text regarding recordkeeping requirements for pneumatic pumps where no control device was on site. This lack of clarity was the result of the affected facility definition for pneumatic pumps. In the final rule, we have revised the definition to clarify that coverage under this rule is independent of availability of a control device on site. Specifically, all natural gas-driven diaphragm pumps at natural gas processing plants or well sites are affected facilities, except for pumps at well sites that operate less than 90 days per calendar year. The EPA has revised the final regulatory text to make clear that all pneumatic pumps affected facilities must be reported on the annual report and records maintained as applicable to control status of the pump.

8. Timing of Initial Compliance

The EPA is also finalizing requirements for pneumatic pump affected facilities at natural gas processing plants. The EPA is finalizing GHG and VOC emissions control requirements for pneumatic pump affected facilities at well sites if there is a control device or ability to route to a process available on site or subsequently installed on site. We are also finalizing a technical infeasibility exception when it is infeasible to route the pneumatic pump to the control device (or route to a process) at non-greenfield sites. An owner or operator applying this exemption must obtain a professional engineering assessment demonstrating the reasons for the exemption.

As pointed out by commenters, the technical infeasibility exemption may be based on safety concerns that could arise when a control device is not designed to handle the additional stream from the pneumatic pump. Commenters also expressed concern about safety issues related to increased pressure on the rest of the closed vent system connected to the control device. In light of these comments, we believe that the proposed 60-day compliance period may be insufficient to identify a qualified professional engineer, obtain the necessary design documents for the existing control device and associated ductwork, evaluate the design documents in light of the increased flow from the pneumatic pump, make an assessment of the technical feasibility of routing the pneumatic pump to the control device, and issue the required certification. Therefore, we are finalizing the compliance period to begin on November 30, 2016 to allow sufficient time for these necessary tasks to be completed.

E. Well Completions

For the well completion requirements, we proposed to require RECs, when technically feasible and in combination with a completion combustion device, for subcategory 1 wells. For subcategory 2 wells, we proposed an operational standard that would require minimization of venting of gas and hydrocarbon vapors during the completion operation through the use of a completion combustion device, with provisions for venting in lieu of combustion for situations in which combustion would present safety hazards. The proposed rule identified challenging issues for which we solicited comment in order to obtain additional information.

The public comment process helped us to identify aspects of the proposed requirements that in practice may not be practical in all cases, and commenters submitted additional information for us to analyze. In this final rule, based on our consideration of the comments received and other relevant information, we have made certain changes to the proposed standards for well completions. The final rule refines the well completion requirements to reduce emissions and provide clarity for both operators and regulators. The EPA is finalizing well completion standards for hydraulically fractured or refractured wells.[81] The final standards require a combination of REC and combustion at subcategory 1 wells and combustion at subcategory 2 wells and low pressure wells. Provided below are the significant changes since proposal that result from the comments we received and our rationale for these changes. For additional details, please refer to section VIII, the TSD, and the RTC supporting documentation in the public docket.

1. Separator Function

The EPA solicited comment on the use of a separator during flowback and whether a separator can be employed for every well completion. We received several comments identifying situations where a separator cannot function. Specifically, commenters noted instances where a separator cannot function due to very low gas flow from the well, contaminated gas flow, or low reservoir pressure requiring artificial lift techniques. Commenters indicate that because of these scenarios there can be a complete absence of a separation flowback stage during the well completion (which, according to the commenters, can be particularly common in some basins and fields). Commenters asserted that many of these circumstances can be anticipated prior to the onset of flowback. Furthermore, commenters stated that the requirement to have a separator onsite would likely

[80] *See* EPA docket ID No. EPA–HQ–OAR–2010–0505.

[81] As noted earlier in section IV, in 2012 EPA promulgated VOC standards for completions of hydraulically fractured or refractured gas wells. Today's action establishes GHG standards for gas well completions, as well as GHG and VOC standards for hydraulically fractured and refractured oil well completions.

cause the operator to incur a cost with no environmental benefit derived.

We believe that commenters have presented legitimate situations where it would be technically infeasible to use a separator, which is required for performing a REC. The challenge is, however, that the factors that lead to technical infeasibility of a separator to function may not be apparent until the time the well completion occurs, at which time it is too late to provide the equipment and, as a result, the well completion will go forward without controls. Further, the commenters did not provide data, and we do not have sufficient data to consistently and accurately identify the subcategory or types of wells for which these circumstances occur regularly or what criteria would be used as the basis for an exemption to the REC requirement such that a separator would not be required to be onsite for these specific well completions. In order to accommodate these concerns raised by commenters, the final rule requires a separator to be onsite during the entire flowback period for subcategory 1 wells (*i.e.,* non-exploratory or non-delineation wells, also known as development wells), but does not require performance of REC where a separator cannot function. We anticipate a subcategory 1 well to be producing or near other producing wells. We therefore anticipate REC equipment (including separators) to be onsite or nearby, or that any separator brought onsite or nearby can be put to use. For the reason stated above, we do not believe that requiring a separator onsite would incur cost with no environmental benefit.

However, unlike subcategory 1 wells, subcategory 2 wells are in areas where gas composition is likely unknown and, therefore, there is less certainty that a separator can work at these wells. If the separator does not work, there are unlikely subcategory 1 wells nearby that can put the separator to use. For the reasons stated above, we are not requiring that a separator be onsite for the well completion of subcategory 2 wells.

The EPA had proposed that, for subcategory 2 wells and low pressure wells, operators would be required to route flowback to a completion combustion device as soon as the separator was able to function. We had based the proposed requirement for these wells on our determination that BSER was combustion, and efficient combustion using traditional combustion devices could be achieved through separation of the gas from the liquid and solid flowback materials prior to routing to the completion combustion device.

As discussed in the 2015 proposal, traditional combustion devices (*e.g.,* flares or enclosed combustors) cannot work initially because the flowback following hydraulic fracturing consists for liquids, gases and sand in high-volume, multiphase slug flow. As a result, these devices can work only after a separator can function. While pit flares can be installed and used from the start, considering the makeup of the initial flowback, we believe there is little gas to be burned, and so we assume there is not an appreciable difference between the amount of emissions reductions between a traditional combustion device and a pit flare. In addition, we believe that pit flares have increased potential for secondary impacts compared to traditional flares, due to the potential for the incomplete combustion of natural gas across the pit flare plume.

Although not required, some owners and operators may choose to separate the gas from the other flowback materials for water management or other purposes. If a separator is used, any separated gas can be routed to combustion. In light of all of the above, we are providing in the final rule two options for completions of subcategory 2 wells: (1) Route all flowback directly to a completion combustion device (in that case a pit flare); or (2) should an owner or operator choose to use a separator, route the separated gas to a completion combustion device as soon as a separator is able to operate.

We are providing the same two options for low pressure wells. We believe that wells cannot perform a REC if there is not sufficient well pressure or gas content during the well completion to operate the surface equipment required for a REC, and low pressure gas could prevent proper operation of the separator. Alternatively, when feasible, some owners and operators may choose to separate the gas from the other flowback materials for water management or other purposes. If a separator is used, any separated gas must be routed to combustion.

2. REC Feasibility

The second instance for potential technical infeasibility occurs during the separation flowback stage, where operators cannot perform a REC and, therefore, must combust. The EPA received comment that additional requirements are necessary to ensure that flaring of the recovered gas during the separation flowback stage is limited to scenarios where all options included in our definition for REC—(1) route the recovered gas from the separator into a gas flow line or collection system, (2) re-inject the recovered gas into the well or another well, (3) use the recovered gas as an onsite fuel source, or (4) use the recovered gas for another useful purpose that a purchased fuel or raw material would serve—have been pursued and their technical infeasibility documented.[82] Commenters identified factors such as the availability and capacity of gathering lines, right of way issues, the quality of gas, and ownership issues that could impact the ability of operators to capture and use gas. Commenters stated that the provision for technical infeasibility for operators to use the recovered gas is vague and runs counter to the improvements the EPA seeks to establish within the oil and gas industry. Other commenters urged the EPA to allow flaring only as a last resort by requiring advanced notification and detailed documentation of the technical infeasibility of capturing and using salable quality gas. Commenters further stated that flaring should be very rarely necessary, as the EPA has identified four separate options for using recovered gas. The commenter recommends that EPA add additional notification and reporting requirements to ensure that all four options have been pursued and their technical infeasibility documented. The EPA agrees that the exemption from REC due to technical infeasibility should be limited. However, as illustrated by the comments received, the circumstances under which a REC is technically infeasible are varied. It is, therefore, difficult to provide one definition that can address all scenarios.

The EPA considered, but declined to require, advanced notification for the following reasons. Technical infeasibility can be an after-the-fact occurrence (*i.e.,* gas was contaminated and not of salable quality or had characteristics prohibiting other beneficial use and, therefore, the gas was combusted); therefore, advanced notification may not always be possible. A case-by-case advance evaluation by a regulatory agency is also not feasible considering the large number of completions, the wide geographic dispersion of the completions and the remote location of many well sites. For these reasons, we are not requiring prior notification of the claim of the technical infeasibility exemption.

Rather we have expanded recordkeeping requirements in the final

[82] This definition is the same as the definition for REC in subpart OOOO which, in response to public comment, included options in addition to routing to a gas line.

rule to include: (1) Detailed documentation of the reasons for the claim of technical infeasibility with respect to all four options provided in section 60.5375a(a)(1)(ii), including but not limited to, names and locations of the nearest gathering line; capture, re-injection, and reuse technologies considered; aspects of gas or equipment prohibiting use of recovered gas as a fuel onsite; and (2) technical considerations prohibiting any other beneficial use of recovered gas onsite. We emphasize that the exemption is limited to ''technical'' infeasibility (*e.g.,* lack of infrastructure, engineering issues, safety concerns).

In addition to the detailed documentation and recordkeeping requirement, the final rule requires that a separator be onsite during the entirety of the flowback period at subcategory 1 (developmental) wells, as described earlier. We believe these additional provisions will support a more diligent and transparent application of the intent of the technical infeasibility exemption from the REC requirement in the final rule. This information must be included in the annual report made available to the public 30 days after submission through the Compliance and Emissions Data Reporting Interface (CEDRI), allowing for public review of best practices and periodic auditing to ensure flaring is limited and emissions are minimized.

3. Gas to Oil Ratio (GOR) Exclusion

We are not finalizing the proposed exclusion of wells with low GOR from the definition of a well affected facility. However, in the final rule, low GOR wells are not subject to REC or combustion requirements. In order to ensure that low GOR claims are not being made without sufficient analysis and oversight, the final rule requires that records used to make the GOR determination must be retained and a certifying official must sign the low GOR determination.

The EPA proposed that wells with a GOR of less than 300 scf of gas per barrel of oil produced would not be affected facilities subject to the well completion provisions of the NSPS.[83] The reason for the proposed threshold GOR of 300 is that separators typically do not operate at a GOR less than 300, which is based on industry experience rather than a vetted technical specification for separator performance. Though in theory any amount of free gas could be separated from the liquid, in reality this is not practical given the design and operating parameters of separation units operating in the field.

The EPA also solicited comment on how operators could identify low GOR wells (*i.e.,* those with a GOR of less than 300 scf of gas per stock tank barrel of oil produced) prior to well completion, specifically the question of whether the GOR of nearby wells would be a reliable indicator in determining the GOR of a new or modified well. The EPA received comment stating that wells in the same area or reservoir could be used to indicate GOR prior to well completion. In light of the comments received and, upon further consideration, the EPA concludes that GOR of a well can be determined in advance. The EPA, therefore, does not believe that it is appropriate to prescribe in the final rule any specific way to determine the GOR for purposes of exempting low GOR wells from performing REC or combustion. However, to ensure that only those that, in fact, have GOR of less than 300 are exempt from the REC or combustion requirement; these wells remain affected facilities under the final rule. To ensure that their GORs are accurately determined, the final rule requires detailed documentation of their GOR determination as well as annual reporting and recordkeeping requirements. However, they are not subject to the REC or combustion requirement.

4. Low Pressure Wells

We have revised the low pressure well definition in the final rule. In the 2012 NSPS, the EPA recognized that certain wells, which the EPA called ''low pressure gas wells,'' cannot implement a REC because of a lack of necessary reservoir pressure to flow gas at rates appropriate for the transportation of solids and liquids from a hydraulically fractured gas well against additional back pressure that would be caused by the REC equipment, thereby making a REC infeasible. The 2012 NSPS exempts these wells from REC and instead requires combustion of the recovered gas.

In the EPA's proposed rule (80 FR 56611, September 18, 2015), in which we proposed to also regulate VOC and GHG emissions from oil wells, we proposed to amend the current requirements for low pressure gas wells to apply to all low pressure wells. We proposed to change the term ''low pressure gas well'' to ''low pressure well'' but keep the definition the same. The substance of the definition at proposal for ''low pressure well'' is the same as the currently codified definition for ''low pressure gas well'' in the 2012 NSPS. We solicited comment on whether this definition appropriately defined hydraulically fractured wells for which conducting a REC would be technologically infeasible or whether the definition should be revised to better characterize the criteria for all low pressure wells.

In our proposed definition, the pressure of the flowback fluid (oil, gas, and water) immediately before it enters the flow line is calculated by equation (1) below:

$$P_L\,(psia) = 0.445 \cdot P_R\,(psia) - 0.038 \cdot L(ft) + 67.578 \quad \text{Equation (1)}$$

Where:

P_L (*psia*) is the pressure of flowback fluid immediately before it enters the flow line;
P_R (*psia*) is the pressure of the reservoir containing oil, gas, and water; and
L(*ft*) is the depth of the well.

The EPA proposed that if the pressure of flowback fluid immediately before it enters the flow line, P_L, calculated using the above equation is less than the available line pressure, the well would be considered a low pressure well. Such a well would not be required to do a REC during flowback (*i.e.,* collect and send the associated gas to the flow line). Instead, such a well would only be required to combust the gas in a completion combustion device.

Commenters asked the EPA to provide a new definition of ''low pressure oil well'' to differentiate oil wells from gas wells. They stated that the definition of ''low pressure well'' set out in proposed section 60.5430a and taken from the definition of ''low pressure gas well'' in subpart OOOO (section 60.5430) is not appropriate for a low pressure oil well, because the surface and back pressure for oil wells is higher than that for gas wells. They further state that ''. . . once the hydraulic fracture load stops coming back, a gas well will typically have much less liquids in the production tubing, making the surface pressure actually higher for the gas well vs. an oil well. This difference would be reflected in the 0.038 number which represents the gas gradient in the well, which would impart a back pressure. For oil wells this back pressure would be higher . . .'' In response to these comments, the EPA modified the existing low pressure gas well equation (equation (1) above) to add pressure drop resulting from flow of oil and water in a well.

The EPA's evaluation of the steady flow of petroleum fluid (gas and oil) during flowback in wells resulted in the following modified equation, hereafter

[83] On February 24, 2015, API submitted a comment to the EPA stating that oil wells with GOR values less than 300 do not have sufficient gas to operate a separator. *http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2014-0831-0137.*

referred to as the low pressure well equation (equation 2 below):

$$P_L\ (psia) = 0.495 \times P_R - \frac{q_g}{q_g+q_o+q_w}[0.05 \times P_R + 0.038 \times L - 67.578] - \left[\frac{q_o}{q_g+q_o+q_w} \times \frac{\rho_o}{144} + \frac{q_w}{q_g+q_o+q_w} 0.433\right] \cdot L \qquad \text{Equation (2)}$$

Where:

P_L is the pressure of flowback fluid immediately before it enters the flow line, expressed in psia;

P_R is the pressure of the reservoir containing oil, gas, and water, expressed in psia;

L is the true vertical depth of the well, expressed in feet;

q_o, q_g, q_w are the flow rates of oil, gas, and water, respectively, in the well, expressed in cubic feet/second; and

ρ_o is the density of oil in the well, expressed in pounds per cubic feet.

EPA's low pressure well equation is used to predict the pressure of the flowback fluid (oil, gas, and water) immediately before it enters the flow line. The low pressure well equation uses inputs similar to those required for the gas well definition and for which information is understood to be available before well completion activity starts at a well site. These inputs include reservoir (or formation) pressure; true vertical depth of the well; flow rates of oil, gas, and water in the well; and the density of oil in the well.

As oil-gas-water mixture flows upwards in a well to a lower pressure location, oil and gas volumes change and some of the dissolved gas evolves out of solution in oil. These phenomena result in oil and gas densities and volumetric flows changing with well depth. Therefore, oil density, ρ_o, and volumetric flow rate, q_o, for use in equation (2) are calculated using the known value of oil API gravity at a well site and the widely used correlations provided in Vasquez and Beggs (1980).[84] The gas volumetric flow, q_g, is calculated using widely used correlations provided in Guo and Ghalambor (2005).[85] Details on using equation (2) to calculate the pressure of flowback fluid immediately before it enters the flow line, P_L, can be found in the TSD in the public docket.

As noted above, equation (2) is the low pressure well equation for all wells in the final rule. This equation predicts the pressure, P_L, of the flowback fluid (oil, gas, and water) immediately before it enters the flow line during the separation flowback period. In response to comments, the EPA's final regulations require that this pressure be compared to the actual flow line pressure available at the well site. Wells with insufficient predicted pressure to produce into the flow line are required to combust the gas in a control device. Wells with sufficient pressure to produce into the flow line are required to capture the gas and produce it into the flow line.

EPA further notes that equation (2) is a modification of equation (1) and adds pressure drop resulting from flows of oil and water. When characterizing a well with conditions of gas flow only (*i.e.,* $q_o = q_w = 0$), equation (2) reduces to equation (1), the equation for gas wells. Also note that equation (2) for line pressure is derived using a vertical well. It is known that inclined wells exist in the field, which will experience a somewhat higher frictional drop due to longer flow length. Nonetheless, it is expected that equation (2) would be able to account for minor increases in pressure drop due to increased frictional drop at inclined wells because the frictional pressure drop component contributes a small amount to the total pressure drop (about 1 percent on average) and conservative assumptions were used in deriving equation (2)—notably, bottom hole pressure equals one-half of formation pressure.

In addition to the revised low pressure well equation, we are providing, in the final definition of low pressure well, other characteristics of the well that would indicate that a well is a low pressure well. We believe that if the static pressure (*i.e.,* pressure with the well shut in and not flowing) at the wellhead following hydraulic fracturing, and prior to the onset of flowback, is less than the flow line pressure at the sales meter, the well is a low pressure well without having to demonstrate that it is such by using the low pressure well equation in the final rule.

Instead of using the equation, under the final rule, operators who suspect that a well may be a low pressure well have the option, for screening purposes, of performing a wellhead static pressure (*i.e.,* pressure with the well shut in and not flowing) check following fracturing and prior to the onset of flowback. If the static pressure at the wellhead was less than the flow line pressure at the sales meter, then the well would be a low pressure well. We believe that such a comparison would be conservative because, for a given well, the static pressure (*i.e.,* with no fluid movement through the well) would be higher than the dynamic pressure (*i.e.,* with the well flowing) because there would be no pressure losses brought about by friction caused by material movement in the tubing string. For some wells, use of this method could eliminate the need for the detailed calculations provided in the low pressure well equation discussed above. For other wells (*i.e.,* those wells where the static pressure was greater than the flow line pressure), it would be necessary for the operator to use the low pressure well equation.

Commenters asserted that many oil reservoirs have pressure that is insufficient for wells to naturally flow even after hydraulic fracturing. The commenters stated that this can be evidenced by the prevalence of artificial lift equipment such as rod pumps visible across the landscape of many oil producing areas. The commenters cited examples of reservoirs such as the Permian Basin, where horizontal drilling is used to extend the life of existing producing formations. The commenters explained that many oil wells that are hydraulically fractured do not have sufficient reservoir pressure to flowback fracture fluids. One company estimated that 30 percent of its hydraulically fractured horizontal wells and 80 percent of its hydraulically fractured vertical wells in the Permian Basin require artificial lift to flowback. In these cases, the commenter explained, rod pumps are installed on the wells to artificially lift the fracture fluids to the surface. In light of the comments received, the EPA believes that wells that require artificial lift equipment for flowback of fracture fluids should be classified as low pressure wells, as we believe that

[84] Vasquez, M. and Beggs, H.D., ''Correlations for fluid physical property prediction,'' JPT, 1980.

[85] Guo, B. and Ghalambor, A., ''Natural Gas Engineering Handbook,'' Gulf Publishing Company, 2005.

performing a REC is technically infeasible for these wells.

To meet the definition of low pressure well, the well must satisfy any of the criteria above. We have revised the definition in the regulatory text to reflect this change. Section VIII, the RTC document, the TSD, and other materials available in the docket provide more discussion of these topics.

5. Timing of Initial Compliance

The EPA proposed the well completion requirements that, if finalized, would apply to both oil and gas well completions using hydraulic fracturing. In the 2012 NSPS, we provided a phase-in approach in the gas well completion requirements due to the concern with insufficient REC and trained personnel if REC were required immediately for all gas well completions. However, we did not provide the same in this proposal on the assumption that the supplies of REC equipment and trained personnel have caught up with the demand and, therefore, are no longer an issue. While some commenters agreed, other commenters indicated that the proposed rule, which would dramatically increase the number of well completions subject to the NSPS, would lead to REC equipment shortages. One commenter estimated that it would take at least 6 months to obtain the necessary equipment, while another commenter estimated that it would take 24 months. One commenter noted that owners and operators have been drilling wells, but delaying completion, due to the current economic conditions affecting the industry, causing a suppressed equipment demand. Finally, one state regulatory agency recommended extending the compliance period to 120 days to allow sufficient time to contract for the necessary completion equipment.

After reviewing the comments, we agree that some owners and operators may have difficulty complying with the REC requirements in the final rule in the near term due to the unavailability of REC equipment. Although REC equipment suppliers have increased production to meet the demand for gas well completions under subpart OOOO, the affected facility under subpart OOOOa includes both gas and oil wells and will more than double the number of wells requiring REC equipment over subpart OOOO. We believe this demand will likely lead to a short-term shortage of REC equipment. However, based on the prior experience, we believe that suppliers have both the capability and incentive to catch up with the demand quickly, as opposed to the longer terms suggested by the commenters; they likely already stepped up production since this rule was proposed last year in anticipation of the impending increase in demand. In light of the above, the final rule provides a phase-in approach that would allow a quick build-up of the REC supplies in the near term. Specifically, for subcategory 1 oil wells, the final rule requires combustion for well completions conducted before November 30, 2016 and REC if technically feasible for well completions conducted thereafter. For subcategory 2 and low pressure oil wells, the final rule requires combustion during well completion, which is the same as that required for completion of subcategory 2 and low pressure gas well in the 2012 NSPS. For gas well completions, which are already subject to well completion requirements in the 2012 NSPS, the requirements remain the same.

F. Fugitive Emissions From Well Sites and Compressor Stations

For fugitive emissions requirements for the source category, three principles or aims directed our efforts. The first aim was to produce a consistent and accountable program for a source to use to identify and repair fugitive emissions at well sites and compressor stations. A second aim was to provide an opportunity for companies to design and implement their own fugitive emissions monitoring and repair programs. The third aim was to focus the fugitive emissions monitoring and repair program on components from which we expected the greatest emissions, with consideration of appropriate exemptions. The fourth aim was to establish a program that would complement other programs currently in place. With these principles in mind, we proposed a detailed monitoring plan; semiannual requirements using OGI technology for monitoring to find and repair sources of fugitive emissions, which we had identified as the BSER; a shifting monitoring schedule based on performance; a 15-day timeframe for repairing and resurveying leaks; and an exemption for low production wells.

The public comment process helped us to identify additional information to consider and provided an opportunity to refine the standards proposed. Commenters specifically identified concerns with the definition of modification for well sites and compressor stations, the monitoring plan, the fluctuating survey frequency, the overlap with state and federal requirements, use of emerging monitoring technologies, the initial compliance timeframe, and the relationship between production level and fugitive emissions.

In this final rule, based on our consideration of the comments received and other relevant information, we have made changes to the proposed standards for fugitive emissions from well sites and compressor stations. The final rule refines the monitoring program requirements while still achieving the main goals. Below we describe the significant changes since proposal for specific topics related to fugitive emissions and our rationale for these changes. For additional details, please refer to section VIII, the TSD, and the RTC supporting documentation in the public docket.

1. Fugitive Emissions From Well Sites

a. Monitoring Frequency

In conjunction with semiannual monitoring, the EPA co-proposed annual monitoring and solicited comment on the availability of trained OGI contractors and OGI instrumentation. 80 FR 56637, September 18, 2015. Commenters provided numerous comments and data regarding annual, semiannual and quarterly monitoring surveys. These comments largely focused on the cost, effectiveness, and feasibility of the different program frequencies. The EPA evaluated these comments and information, as well as certain production segment equipment counts from the 2016 public review draft GHG Inventory, which were developed from the data reported to the GHGRP. Based on the above information, the EPA updated its proposal assumptions on equipment counts per well site to use data from the 2016 public review draft update. This resulted in changes to the well site model plant. Specifically, the equipment count for meters/piping at a gas well site increased from 1 to 3, which tripled the component counts from meters/piping at these sites. In addition, the EPA developed a third model plant to represent associated gas well sites. This category includes wells with GOR between 300 and 100,000 standard cubic feet per barrel (scf/bbl), and the model plant is assumed to have the same component counts as the model oil well site, as well as components associated with meters/piping. The EPA used this information to re-evaluate the control options for annual, semiannual and quarterly monitoring. As shown in the TSD, the control cost, using OGI, based on quarterly monitoring is not cost-effective, while both semiannual and annual monitoring remain cost-effective for reducing GHG (in the form of methane) and VOC emissions. Because control costs for both semiannual and annual monitoring are cost-effective, we evaluated the difference in emissions reductions between the two monitoring frequencies and concluded that semiannual monitoring would achieve greater emissions reductions. Therefore, the EPA is finalizing the proposed semiannual monitoring frequency. Please see the RTC document in the public docket for further discussion.[86] Even though the EPA has determined that semi-annual surveys for well sites is the BSER under this NSPS, this does not preclude the EPA from taking a different approach in the future, including requiring more frequent monitoring (*e.g.,* quarterly).

b. Low Production Well Sites

The EPA proposed to exclude low production well sites (*i.e.,* well sites where the average combined oil and natural gas production is less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production) from the fugitive emissions monitoring and repair requirements for well sites. As we explained in the preamble to the proposed rule, we believed that these wells are mostly owned by small businesses and that fugitive emissions associated with these wells are generally low. 80 FR 56639, September 18, 2015. We were concerned about the burden on small businesses, in particular, where there may be little emission reduction to be achieved. Id. We specifically requested comment on the proposed exclusion and the appropriateness of the 15 boe per day threshold. We also requested data that would confirm that low production sites have low GHG and VOC fugitive emissions.

Several commenters indicated that low production well sites should be exempt from fugitive emissions monitoring and that the 15 boe per day threshold averaged over the first 30 days of production is appropriate for the exemption, however, commenters did not provide data. Other commenters indicated that the low production well sites exemption would not benefit small businesses since these types of wells would not be economical to operate and few operators, if any, would operate new well sites that average 15 boe per day.

Several commenters stated that the EPA should not exempt low production well sites because they are still a part of the cumulative emissions that would impact the environment. One commenter indicated that low production well sites have the potential to emit high fugitive emissions. Another commenter stated that low production well sites should be required to perform fugitive emissions monitoring at a quarterly or monthly frequency. One commenter provided an estimate of low producing gas and oil wells that indicated that a significant number of wells would be excluded from fugitive emissions monitoring.

Based on the data from DrillingInfo, 30 percent of natural gas wells are low production wells, and 43 percent of all oil wells are low production wells. The EPA believes that low production well sites have the same type of equipment (*e.g.,* separators, storage vessels) and components (*e.g.,* valves, flanges) as production well sites with production greater than 15 boe per day. Because we did not receive additional data on equipment or component counts for low production wells, we believe that a low production well model plant would have the same equipment and component counts as a non-low production well site. This would indicate that the emissions from low production well sites could be similar to that of non-low production well sites. We also believe that this type of well may be developed for leasing purposes but is typically unmanned and not visited as often as other well sites that would allow fugitive emissions to go undetected. We did not receive data showing that low production well sites have lower GHG (principally as methane) or VOC emissions other than non-low production well sites. In fact, the data that were provided indicated that the potential emissions from these well sites could be as significant as the emissions from non-low production well sites because the type of equipment and the well pressures are more than likely the same. In discussions with us, stakeholders indicated that well site fugitive emissions are not correlated with levels of production, but rather based on the number of pieces of equipment and components. Therefore, we believe that the fugitive emissions from low production and non-low production well sites are comparable.

Based on these considerations and, in particular, the large number of low production wells and the similarities between well sites with production greater than 15 boe per day and low production well sites in terms of the components that could leak and the associated emissions, we are not exempting low production well sites from the fugitive emissions monitoring program. Therefore, the collection of fugitive emissions components at all new, modified or reconstructed well sites is an affected facility and must meet the requirements of the fugitive emissions monitoring program.

c. Monitoring Using Method 21

The EPA's analysis for the proposed rule found OGI to be more cost-effective at detecting fugitive emissions than the traditional protocol for that purpose, Method 21, and the EPA, therefore, identified OGI as the BSER for monitoring fugitive emissions at well sites. See 80 FR 56636, September 18, 2015. The EPA solicited comment on whether to allow Method 21 as an alternative fugitive emissions monitoring method to OGI. 80 FR 56638, September 18, 2015. We also solicited comment on the repair threshold for components that are found to have fugitive emissions using Method 21. *Id.*

Numerous industry, state, and environmental commenters indicated that Method 21 is preferred or should be allowed as an alternative to OGI, citing availability, costs, and training associated with OGI.

Several commenters indicated that the EPA should set the Method 21 fugitive emissions repair threshold at 10,000 ppm, the level at which our recent work indicates that fugitive emissions are generally detectable using OGI instrumentation provided that the right operating conditions (*e.g.,* wind speed and background temperature) are present. 80 FR 56635, September 18, 2015. Some commenters stated that the repair threshold should be 500 ppm to achieve a high level of fugitive emission reductions while other commenters state that a 500 ppm repair threshold would target fugitive emissions that would not provide meaningful reductions.

The issue of the repair threshold when Method 21 is used is a critical decision. As discussed in the preamble to the proposed rule, Method 21, at an appropriate repair threshold, is capable of achieving the same or better emission reductions as OGI. However, at proposal, we determined that Method 21 was not cost-effective at a semiannual monitoring frequency with a repair threshold of 500 ppm.

While we agree with the importance of allowing the use of Method 21 as an alternative, we need to ensure that its use does not result in fewer emissions reductions than what would otherwise be achieved using OGI, which is the BSER based on our analysis. Available data show that OGI can detect fugitive emissions at a concentration of at least 10,000 ppm when restricting its use during certain environmental conditions

[86] See EPA docket ID No. EPA–HQ–OAR–2010–0505.

such as high wind speeds. Due to the dynamic nature for the OGI detection capabilities, OGI may also image emissions at a lower concentration when environmental conditions are ideal. Because an OGI instrument can only visualize emissions and not the corresponding concentration, any components with visible emissions, including those emissions that are less than 10,000 ppm, would be repaired. Method 21 is capable of detecting fugitive emissions at concentrations well below 10,000 ppm. However, if the repair threshold was set at 10,000 ppm, an owner or operator would not have to repair any leaks that are less than 10,000 ppm, thereby foregoing the reductions that would otherwise be achieved by using the OGI. For the reason outlined in this section, 10,000 ppm is not an appropriate repair threshold for Method 21.

Using information provided by commenters, we evaluated the methane and VOC emission reductions associated with the use of Method 21 at repair thresholds of 10,000 ppm and 500 ppm, the two levels recommended by the various commenters. We used AP–42 emission factors to determine the emissions from fugitive emissions components that were found to be leaking using a Method 21 instrument and concluded that emissions reductions are lower than when OGI is used to survey the same components. The lower emission reductions are due to fugitive emissions with a concentration lower than 10,000 ppm not being found using the Method 21 instrument when it is calibrated to detect emissions at a threshold of 10,000 ppm or greater.

We then calculated the emission reductions that result from using a Method 21 instrument to conduct a monitoring survey at a repair threshold of 500 ppm. At this threshold, the operator would have to repair every component found to have fugitive emissions over 500 ppm threshold. This results in emission reductions greater than the emissions reductions that would be achieved if OGI were used instead. For the reasons stated in this section, using Method 21 to conduct monitoring surveys at a repair threshold of 500 ppm is better than, or at least equivalent to, using OGI to conduct the same survey; we are allowing it in the final rule as an alternative to the use of OGI. We acknowledge that the cost of conducting a survey using Method 21 may be more expensive than using OGI; however, some owners or operators may still chose to use Method 21 for convenience or due to the lack of availability of OGI instruments or trained personnel. Therefore, to ensure that it achieves at least the level of emission reduction to be achieved using the OGI, the final rule allows the use of Method 21 with a repair threshold of 500 ppm.

Based on interest in having Method 21 as an approved alternative, we are finalizing it as an alternative to OGI. Allowing Method 21 as an alternative will address some of the uncertainty expressed by small entities that indicated a concern with needing to purchase an OGI instrument or hire trained OGI contractors to perform their monitoring surveys. We are finalizing Method 21 as an alternative to OGI for monitoring fugitive emissions components at a repair threshold of an instrument reading of 500 ppm or greater. We are also finalizing specific recordkeeping and reporting requirements when Method 21 is used to perform a monitoring survey.

d. Shifting of Monitoring Frequency Based on Performance

The EPA proposed shifting monitoring frequencies (ranging from annual to quarterly monitoring) based on the percentage of components that are found to have fugitive emissions during a monitoring survey. We solicited comment on the proposed monitoring approach, including the proposed metrics of one percent and three percent to determine monitoring frequency or whether the monitoring frequency thresholds should be based on a specific number of components that are found to have fugitive emissions. In addition, the EPA solicited comment on whether a performance-based frequency or a fixed-frequency program was more appropriate.

Most commenters opposed performance-based monitoring frequency. They raised specific concerns that performance-based monitoring and shifting monitoring frequencies would be costly, time-consuming, and impose a complex administrative burden for the industry and states. For example, commenters pointed out that an owner may have hundreds or even thousands of well sites and a potentially ever-changing survey schedule for each of those sites would present an untenable logistical hurdle. Most of the commenters stated that the EPA should finalize a fixed monitoring frequency to provide a level of certainty to owners and operators for planning future schedules of survey crews.

The EPA considered these comments and agrees that imposing a performance-based monitoring schedule would require operators to develop an extensive administrative program to ensure compliance. Under the performance-based monitoring, owners and operators would need to count all of the components at the well sites, affix identification tags on each component or develop detailed piping and instrument diagram. During each monitoring survey, owners and operators would need to calculate the percentage of leaking fugitive emissions components to determine the next monitoring frequency schedule.

We also agree that the shifting monitoring frequencies could cause regulated entities additional administrative burden to determine compliance since the monitoring frequencies could change each year, but the correct frequency may not be reflected in the operating permit. This could also result in fugitive emissions being undetected longer due to less frequent monitoring. We believe that the potential for a performance–based approach to encourage greater compliance is outweighed in this case by these additional burdens and the complexity it would add. Therefore, the EPA is finalizing a fixed-frequency monitoring instead of performance-based monitoring.

e. Fugitive Emissions Components Repair and Resurvey

The EPA proposed that components that are a source of fugitive emissions must be repaired or replaced as soon as practicable and, in any case, no later than 15 calendar days after detection of the fugitive emissions. For sources of fugitive emissions that cannot be repaired within 15 days of finding the emissions, due to technical infeasibility or unsafe conditions, the EPA proposed that the components could be placed on a delay of repair until the next scheduled shutdown or within six months, whichever is earlier. We also proposed that a repaired fugitive emissions component be resurveyed within 15 days of the repair. The EPA solicited comment on all three aspects.

Commenters voiced various opinions regarding the requirements. Many commenters shared concerns that the 15-day window for repairs is too short, due to factors such as remoteness of equipment locations, unsuccessful repair attempts, and multiple components needing repair. Other commenters preferred the 15-day window, in the interest of achieving immediate mitigation of health and safety risks and alignment with standards in several states.

Multiple commenters provided comments on the proposed delay of repair standards, including concerns about delays lasting longer than six months due to availability of supplies needed to complete repairs and information regarding the frequency of delayed repairs. Some commenters also indicated that in some cases, requiring prompt repairs could lead to more emissions than if repairs were able to be delayed, for example if a well shut-in or vent blow-down is required.

Regarding the 15-day window to resurvey repairs to fugitive emissions components, multiple commenters stated that the final rule should allow 30 days for the resurvey, due to the potential need for specialized personnel for the resurvey, while others considered 15 days to be adequate. Regarding performance of the resurvey, many commenters also suggested that soap bubbles, as specified in section 8.3.3 of Method 21, be allowed to determine if the components have been repaired.

After considering the comments above, the EPA agrees that repairs for some sources of fugitive emissions at a well site may take multiple attempts or require additional equipment that is not readily available and may take longer than 15 days to repair. Well sites, unlike chemical plants or refineries, may be located in remote areas and it is unlikely that they would have warehouses or maintenance shops nearby where spare equipment or tools are kept that would be needed to perform repairs within 15 days. We also recognize that fugitive emissions must be alleviated as soon as practicable. We believe that allowing an additional 15 days for repair would give owners and operators enough time to get the parts or the personnel needed to repair or replace the components that could not be repaired during the initial monitoring survey. Therefore, we are finalizing 30 days for the repair of fugitive emissions sources. However, we do recognize that some state LDAR programs require repairs to be made within 5 to 15 days of finding a leak. We encourage operators to continue to fix leaks within that timeframe, since the majority of leaks are fixed when they are found. We do expect that the majority of components will not need the additional 15 days for repair.

The EPA agrees, based on our review of the comments, that only a small percentage of components would not be able to be repaired during that 30 day period. We also agree that a complete well shutdown or a well shut-in may be necessary to repair certain components, such as components on the wellhead, and this could result in greater emissions than what would be emitted by the leaking component. The EPA does not agree that unavailability of supplies or custom parts is a justification for delaying repair (*i.e.*, beyond the 30 days for repair provided in this final rule) since the operator can plan for repair of fugitive emission components by having stock readily accessible or obtaining the parts within 30 days after finding the fugitive emissions.

Based on available information, it may be two years before a well is shut-in or shutdown. Therefore, to avoid the excess emissions (and cost) of prematurely forcing a shutdown, we are amending the rule to allow 2 years to fix a leak where it is determined to be technically infeasible to repair within 30 days; however, if an unscheduled or emergency vent blowdown, compressor station shutdown, well shutdown, or well shut-in occurs during the delay of repair period, the fugitive emissions components would need to be fixed at that time. The owner or operator will have to record the number and types of components that are placed on delay of repair and record an explanation for each delay of repair.

Method 21 allows a user to spray a soap solution on components that are operating under certain conditions (*e.g.*, no continuous moving parts or no surface temperatures above the boiling point or below the freezing point of the soap solution) to determine if any soap bubbles form. If no bubbles form, the components are deemed to be operating with no detected emissions. We note that spraying soap solution to confirm whether a component has been repaired may not work for all fugitive emissions components, such as a leak found under the hood of the thief hatch because it would be difficult to apply the soap solution or observe bubbles. However, we believe that this alternative will provide some owners and operators a simple, low cost way to confirm that a fugitive emissions component has been repaired. This would also allow the resurveys to be performed by the same personnel that completed the repairs instead of other certified monitoring personnel or hired contractors that would have to come back to verify the repairs. Therefore, we are finalizing the use of the alternative screening procedures specified in Section 8.3.3 of Method 21 for resurveying repaired fugitive emissions components, where appropriate.

For owners or operators that cannot use soap spray to verify repairs, we are allowing an additional 30 days for resurvey of the repaired fugitive emissions components, to allow time for contractors or designated OGI personnel to perform the resurvey because they are not typically the same personnel that would perform the repairs.

f. Definition of ''Fugitive Emission Component''

As just discussed, we proposed monitoring, repair, and resurvey of ''fugitive emission components.'' The EPA solicited comment on the proposed definition of fugitive emissions components. Commenters indicated that, as proposed, the fugitive emissions component definition is too broad and vague, because it contains both equipment and component types, and suggested that the EPA modify the definition to be more targeted and easier for states and other regulatory authorities to determine compliance, and recommended other definitions, such as that used by the state of Colorado.

The EPA agrees with commenters that, as proposed, the fugitive emissions component definition may cause confusion due to inclusion of equipment types, such as uncontrolled storage vessels that are potential sources of vented emissions (as opposed to fugitive emissions), in the definition.

Therefore, we are finalizing changes to the definition to remove equipment types and identify specific components, such as valves and flanges, that have the potential to be sources of fugitive emissions and that, when surveyed and repaired, would significantly reduce GHG and VOC emissions. This targeted list will remove the ambiguity of the proposed definition and will allow owners and operators to consistently identify fugitive emissions at well sites. We are finalizing the definition for fugitive emissions components in § 60.4530a of this final rule.

As finalized, the definition also aligns closely with other states' and federal agencies' definitions of fugitive emissions components by targeting similar components to the components in those definitions. Owners and operators can therefore monitor one set of components while complying with the requirements of this final rule and other state or federal fugitive emissions monitoring programs.

g. Timing of the Initial Monitoring Survey

The EPA proposed that the initial monitoring be conducted within 30 days after the initial startup of the first well completion or modification of a well site. EPA solicited comment on whether the proposal provides an appropriate amount of time to begin conducting fugitive emissions monitoring. We received a wide variety of comments and suggestions for the appropriate time for fugitive emissions monitoring to begin.

Several commenters indicated that initial monitoring should begin after production starts, because time is needed to close out the drilling activities. The commenters further stated that completion activities and the transition from completion to production at well sites is unpredictable and temporary completion equipment may still be onsite 30 days after the ''initial startup of the first well completion.'' One commenter indicated that production may not begin immediately after a well completion, so initial monitoring should not begin until after production starts.

The EPA acknowledges that at the time of a well completion all of the associated permanent equipment may not be present and conducting the initial monitoring survey may not capture all of the fugitive emissions components that would be in operation during production. In addition, we believe it is important to conduct the initial survey soon after the permanent equipment is in place to catch any improperly installed or defective equipment that may have substantial fugitive emissions immediately after installation. We believe that the permanent equipment will be in place at the startup of production (*i.e.*, the initial flow following the end of the flowback when there is continuous recovery of saleable quality gas). Therefore, the startup of production more accurately reflects the start of normal operations and would capture any fugitive emissions from the newly constructed or modified components at the well site. Therefore, we are finalizing that the startup of production marks the beginning of the initial monitoring survey period for the collection of fugitive emissions components.

Furthermore, based on the comments received, we are concerned that the tasks required prior to conducting an initial survey would take more than the 30 days we had proposed. Because each new or modified well site must be covered by a monitoring plan for a company-defined area, owners and operators must visit and assess each new or modified well site in order to incorporate it into a newly developed or modified monitoring plan for that area. They also need to secure certified monitoring survey contractors or monitoring instruments. In addition, they need to ensure that other compliance requirements will be met, such as recordkeeping and reporting. In light of the activities described above, the EPA is requiring in the final rule that the initial survey be conducted within 60 days from the startup of production.

While 60 days from startup of production is sufficient time to conduct the initial survey once the underlying program infrastructure is established, we recognize that the initial establishment of the required program's infrastructure and the initial round of monitoring surveys will require additional time. Most importantly, additional time is needed to secure the necessary equipment or trained personnel, according to one OGI instrument manufacturer, which commented that they would need to increase production of key components for the OGI instrument to meet demand. The OGI manufacturer also indicated that they would need to scale up the number of personnel needed to provide OGI training and service of the equipment. We are concerned that currently there is not sufficient equipment and trained personnel to meet the demand imposed by this final rule in the near term. Accordingly, it will be necessary to have a window of time for trained personnel to work through this backlog. Furthermore, as previously mentioned, an owner or operator will need to develop a monitoring plan that would apply to each well site located within the company-defined area, which requires an assessment of each well site. Therefore, before a plan can be developed or modified, the owner or operator would need time to visit each well site within the company-defined area. Based on the information that we used to develop the model well site plants, each company-defined area may consist of up to 22 well sites within a 70-mile radius of a central or district office. In light of the above, the initial site visits and development of the monitoring plan would require a significant amount of time. Time is also needed to secure certified monitoring survey contractors or monitoring instruments. In addition, owners and operators will need to plan the logistics of the initial activities in order to comply with the requirements. This includes time to set up recordkeeping systems and to train personnel to manage the fugitive emissions monitoring program. These corporate systems are critical for submitting the notification of initial and subsequent annual compliance status.

As noted above, once programs are established and equipment supplies have caught up, well owners will be able to add additional affected facilities to existing programs and, thus, this longer timeline will not be needed. Therefore, in order to provide time for owners and operators to establish the initial groundwork of their fugitives program, we are requiring that the initial monitoring survey must take place by June 3, 2017 or within 60 days of the startup of production, whichever is later.[87] We anticipate that sources will begin to phase in these requirements as additional devices and trained personnel become available. For additional discussion, please refer to the materials in the docket.

h. Monitoring Plan

The EPA proposed that owners or operators develop a corporate-wide fugitive emissions monitoring plan that specifies the measures for locating sources and the detection technology to be used. We also proposed that, in addition to the corporate-wide monitoring plan, owners or operators develop a site-specific fugitive emissions monitoring plan that specifies information such as the number of fugitive emission components that pertains to that single site.[88] The EPA solicited comment on the required elements of the proposed corporate-wide monitoring plan; specifically, the EPA asked for comment on whether other techniques, such as visual inspections to help identify indicators of potential leaks, should be included within the monitoring plan.

Some commenters agreed with the EPA's proposal to require a corporate-wide fugitive monitoring plan but expressed concerns about the elements of the plan, while others objected that the proposed plan is overly prescriptive and costly, with particular concerns about including requirements for a walking path and for digital photographs. Other commenters suggested changing the scope of monitoring plans to accommodate variations in locations of contractors and equipment.

We considered these comments, and we have made the following changes to the proposal in the final rule.

First, the final rule requires owners or operators to develop a fugitive emission monitoring plan for well sites within a company-defined area instead of corporate-wide and site-specific monitoring plans. This will give companies the flexibility to group well sites that are located within close proximity, under common control within a field or district, or that are

[87] For well site activities, such as the installation of a new well, a hydraulically fractured or refractured well, which commenced on or after September 18, 2015 are subject to this rule once it is finalized.

[88] See 80 FR 56612 (September 18, 2015).

managed by a single group of personnel. This would also afford owners and operators of well sites within different basins the ability to tailor their plans for the specific elements within each basin (*i.e.*, geography, well site characterization, emission profile). Information we received indicates that, in many cases, several sites within a specific geographic area may have similar equipment and would use the same contractors, company-owned monitoring instruments, or company personnel to perform the monitoring surveys. Based on a study conducted for the city of Fort Worth, Texas, we estimate that, on average, there are 22 well sites within a company's specific geographic region.[89] In this study, a total of 375 well pads were identified in the Fort Worth area, and these well pads were owned and operated by 17 different companies, or an average of 22 well pads per company. We believe these data provide a reasonable estimate of the number of well sites operated by a company in a specific geographic region. Therefore, we are removing the proposed corporate-wide and site-specific monitoring plan requirements and finalizing requirements that owners and operators develop a fugitive emissions monitoring plan for each of the company-defined areas that covers the collection of fugitive emissions components at well sites. As a result, the final rule requires owners and operators to develop a plan that describes the sites generally, including descriptions of equipment, plans for how they will monitor, etc., that apply to all similar sites. This will allow owners and operators to develop a monitoring plan for groups of similar well sites within an area for ease of implementation and compliance.

Second, we have made changes in the final rule to the proposed digital photograph requirements. We believe concerns regarding the burden of printing or transmitting digital pictures within the annual report are the result of unclear language in the proposed rule. Our intent was to require the owner or operator to include one or more digital photographs of the survey being performed. However, we inadvertently included that text within the requirement for each fugitive emission. It was not our intent to require a digital photograph of each fugitive emission in the annual report; instead we wanted to ensure, through pictorial documentation, that the monitoring survey had been performed. After consideration of the comments received, we believe we can further streamline this requirement. Because a source with fugitive emissions during the reporting period is subject to other recordkeeping and reporting requirements, this provides sufficient documentation that the survey was performed. Therefore, we have removed the proposed requirement to provide a digital photograph in the annual report for each required monitoring survey. We are requiring owners and operators to retain a record of each monitoring survey performed with optical gas imaging by keeping one or more digital photographs or videos captured with the OGI instrument. The photograph or video must either include the latitude and longitude of the collection of fugitive emissions components imbedded within the photograph or video or must consist of an image of the monitoring survey being performed with a separately operating GPS device within the same digital picture or video, provided that the latitude and longitude output of the GPS unit can be clearly read in the image.

Third, with the allowance for Method 21 monitoring as an alternative to OGI instrument monitoring, we are finalizing a requirement that sources of fugitive emissions (*e.g.*, a leaking fugitive emissions component) that cannot be repaired during the initial monitoring survey either be temporarily tagged for identification for repair or be digitally photographed or video recorded in a way that identifies the location of the fugitive emissions component needing repair. If an owner or operator chooses to digitally photograph the leaking component(s) instead of using identification tags, the photograph will meet the requirement to take a digital photograph during a monitoring survey, as long as the digital photograph is taken with the OGI instrument and includes the latitude and longitude either imbedded in the photograph or visible in the picture.

Fourth, we are finalizing the walking path requirement with minor changes. We are revising the walking path terminology to observation path in order to clarify that our intent is focused on the field of view of the OGI instrument, not the physical location of the OGI operator. We believe this terminology change will alleviate commenters' concerns regarding the potentially overly prescriptive nature of the defined walking path with transient interferences, environmental obstructions, weather conditions and safety issues. This revision also clarifies our intent to allow for the use of all types of OGI instruments (*e.g.*, mounted, handheld or remote controlled).

The purpose of the observation path is to ensure that the OGI operator visualizes all of the components that must be monitored, just as a Method 21 operator in a traditional leak detection program surveys all of the components. In the traditional scenario, the owner or operator tags all of the equipment that must be monitored, and when the Method 21 operator subsequently inspects the affected facility, the operator scans each component's tag and notes the component's instrument reading. The EPA realizes that this is a time-consuming practice. Additionally, while the Method 21 operator must contact each component with the probe of the Method 21 instrument and monitor it individually, we recognize that with OGI, the operator can be away from the components and still monitor several components simultaneously.

Recognizing these aspects of traditional and OGI leak detection methods, we want to offer owners and operators an alternative to the traditional tagging approach. However, because we are no longer requiring a traditional log of instrument readings, the rule must provide another way to ensure that the compliance obligation to monitor all equipment is met. We believe that the observation path requirement effectively ensures that an operator looks at all of the required components but reduces the burden of tagging and logging associated with traditional Method 21 programs. Unlike the tagging and logging requirement associated with traditional Method 21 programs, the requirement to develop an observation path is a one-time requirement (as long as the path does not need to change due to the addition of components). We do not expect facilities to create overly detailed process and instrumentation diagrams to describe the observation path. The observation path description could be a simple schematic diagram of the facility site or an aerial photograph of the facility site, as long as such a photograph clearly shows locations of the components and the OGI operator's walking path. As a result, we do not believe that the requirement to document the observation path is burdensome.

i. Provision for Emerging Technology

As the EPA noted in the 2015 proposal, fugitive emissions monitoring is a field of emerging technology, and major advances are expected in the near future. 80 FR at 56639. We are seeing a rapidly growing push to develop and

[89] 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.*

produce low-cost monitoring technologies to find fugitive and direct methane and VOC emissions sooner and at lower levels than current technology allows, thus enhancing the ability of operators to detect fugitive emissions. During the development of the proposed rule, the EPA solicited comments and information on emerging technologies that could potentially be used to detect fugitive emissions at well sites or compressor stations and how these technologies could be used (*e.g.*, as standalone monitors or in conjunction with OGI). Several commenters indicated that methane and VOC leak detection technology is undergoing continuous and rapid development and innovation, potentially yielding, for example, continuous emissions monitoring technologies, and urged the EPA to allow emerging technology to be used for fugitive emissions monitoring. The EPA agrees that continued development of these cost effective technologies is important and that the final rule should encourage and accommodate it to the extent possible.

Fugitive emissions monitoring and repair is a work practice standard, as allowed under section 111(h)(1) of the CAA. A work practice standard is an emission limitation that is not necessarily in a numeric format, such as the visualization of fugitive emissions using OGI. As described in section 111(h)(3), the Administrator may approve an alternative means of emission limitation for a work practice standard if it can be proven that an equal reduction in emissions will be achieved. To that end, pursuant to CAA section 111(h)(3), we are establishing in the final rule a process for the agency to permit the use of innovative technology for reducing fugitive emissions at well sites and/or compressor stations. Specifically, under the final rule, owners or operators may submit a request to the EPA for ''an alternative means of emission limitation'' where a technology has been demonstrated to achieve a reduction in emissions at least equivalent to the reduction in emissions achieved under the work practice or operational requirements for reducing fugitive emissions at well sites and/or compressor stations in subpart OOOOa.

To facilitate the application and review process, the final rule includes information to be provided in the application that would be needed for us to expeditiously evaluate the emerging technology. Such information must include a description of the emerging technology and the associated monitoring instrument or measurement technology; a description of the method and data quality used to ensure the effectiveness of the technology; a description of the method detection limit of the technology and the action level at which fugitive emissions would be detected; a description of the quality assurance and control measures employed by the technology; field data that verify the feasibility and detection capabilities of the technology; and any restrictions for using the technology.

This process will allow for the use of any currently emerging technology or any technology that is developed in the future that is capable of achieving methane and VOC emission reductions at levels that are at least equivalent to reductions achieved when using OGI or Method 21 for fugitive emissions monitoring. This process will also allow for the use of alternative fugitive emissions monitoring approaches such as periodic, continuous, fixed, mobile, or a hybrid approach. Consistent with section 111(h)(3), any application will be publicly noticed in the **Federal Register**, which the EPA intends to provide within six months after receiving a complete application, including all required information for evaluation. The EPA will provide an opportunity for public hearing and comment on the application and on intended action the EPA might take. The EPA intends to make a final determination within six months after the close of the public comment period. The EPA will also publish its final determination in the **Federal Register**. If final determination is a denial, the EPA will provide reasoning for denial and recommendations for further development and evaluation of the emerging technology, if appropriate.

j. Definition of Well Site

In the proposed rule, we had defined ''well site,'' for purposes of the fugitive emissions standards at § 60.5397a, to include separately located, centralized tank batteries. We received comments that the definition was unclear and that there was concern that the affected facility status of centralized tank batteries could inadvertently pull into affected facility status those well sites that only contain one or more wellheads, which were proposed to be excluded from affected facility status. We agree that the proposed definition of well site was somewhat unclear, and we have revised the definition in the final rule. With regard to the affected facility status of centralized tank batteries and its effect on well sites that only contain one or more wellheads, our intent is not to have well sites that only contain one or more wellheads subject to fugitive emissions standards. To make this intent more explicit, we have added language to § 60.5365a(i)(2) to this effect.

2. Fugitive Emissions From Compressor Stations

Based on our consideration of the comments received and other relevant information, we have made several changes to the proposed fugitive emissions standards for the compressor stations in this final rule. The finalized fugitive emissions monitoring and repair requirements for compressor stations are similar to the requirements for well sites, so we streamlined this section by referencing our well site discussion, where appropriate. Below we provide the significant changes since proposal and our rationales for these changes.

a. Monitoring Frequency

In conjunction with semiannual monitoring, the EPA co-proposed annual monitoring, solicited comment on conducting monitoring surveys on a quarterly basis, and solicited comment on the availability of trained OGI contractors and OGI instrumentation. 80 FR at 56639.

Some commenters supported quarterly monitoring on the belief that it is more accurate and cost-effective than the monitoring frequencies proposed by the EPA. Other commenters opposed quarterly monitoring, alleging that it is not cost-effective and may be infeasible due to weather or shortages associated with OGI, necessary for the surveys. Also citing factors such as cost-effectiveness and questioning data underlying the EPA's analysis, some commenters supported annual monitoring or generally opposed semiannual monitoring.

Based on the comments received, the EPA reviewed the type of equipment and the associated components that were included in the model plant used to determine emission reductions and costs for compressor stations at proposal. The storage and transmission model plants developed for the proposed rule had inadvertently included site blowdown open-ended lines, which are not sources of fugitive emissions but are vents. Therefore, the transmission and storage model plants were revised for the final rule to remove these components from the total component count.

The EPA used information provided by commenters to re-evaluate the control options for annual, semiannual and quarterly monitoring. As shown in the TSD, the control costs for quarterly, semiannual, and annual monitoring remain cost-effective for reducing GHG (in the form of methane) and VOC emissions. Semiannual and quarterly monitoring would provide greater emissions reductions than would annual monitoring. However, as explained in the proposed rule, we were concerned with compliance burden, in particular for small businesses, associated with quarterly monitoring even though it was cost effective. 80 FR at 56641. Specifically, we were concerned that the limited supplies of trained personnel for performing surveys might lead to disadvantages for small businesses, which are more likely to hire trained personnel. *Id.* However, certain changes we have made in the final rule will help alleviate the concern. For example, the final rule requires that the initial monitoring survey must take place by June 3, 2017 or within 60 days of the startup of production, whichever is later. This allows additional time for owners and operators to establish the requirement program's infrastructure at the initial stage. Another example, in light of comments urging EPA to allow Method 21 as an alternative, and the fact that we know many companies already own Method 21 instruments, offering Method 21 at a repair threshold of 500 ppm, as an alternative to conduct the monitoring surveys, will alleviate some of the demand for OGI instruments and personnel. Therefore, the EPA is finalizing quarterly monitoring frequency for the collection of fugitive emissions components at compressor stations to ensure the maximum amount of emission reductions. Please see the RTC document in the public docket for further discussion.[90]

Some commenters requested that fugitive emissions monitoring exemptions be given to well sites and compressor stations that are located in areas of the country that routinely experience extreme weather. The commenters noted that these areas experience several months of average temperatures below 0 °F and long periods of snow cover. The commenter also provided information from one of the OGI instrument manufacturers which indicates that the instrument cannot operate at temperatures below −4 °F. The commenter also expressed concerns about monitoring survey personnel's safety if they were to attempt to conduct surveys in these weather conditions.

We agree that there are areas within the United States that regularly have extreme weather conditions such as three or more consecutive months of average temperatures below 0 °F. We also obtained information from two OGI instrument manufacturers that confirm that the minimum operating temperature of the OGI instruments is −4 °F. As such, these prolonged subzero temperature conditions would make performing fugitive emissions monitoring surveys impossible during several months of the year. Additionally, while we believe that company personnel may be accessing these sites for maintenance activities, it may be difficult to transport OGI contractors to unmanned sites within these areas during these periods, as outside access for OGI contractors usually requires air travel to access these production sites.

Based on these considerations, we are waiving quarterly fugitive emissions monitoring surveys at compressor stations if, based on three years of historical climatic data, two of the three consecutive months within the quarter has an average temperature below 0 °F. The average temperatures must be determined by historical climatic data from the National Oceanic and Atmospheric Administration or a source approved by the EPA Administrator. This waiver may not be used for two consecutive quarters and is not extended to well sites because we do not believe that there will be any locations that have average monthly temperatures below 0 °F for six consecutive months. Owners and operators will have to keep records of the waiver period, including the three months within the quarterly monitoring period, the average monthly temperatures and the source of the temperature information. Owners and operators will also have to report this information in their annual report.

b. Monitoring Using Method 21

In performing analysis for the proposed rule, the EPA found OGI to be more cost-effective than Method 21 and, therefore, identified OGI as the BSER for monitoring fugitive emissions at compressor stations. See 80 FR 56641, September 18, 2015. As with well sites, discussed previously in section VI.F.1.c, the EPA solicited comment on whether to allow Method 21 as an alternative fugitive emissions monitoring method to OGI and solicited comment on the repair threshold for components that are found to have fugitive emissions using Method 21.

The EPA received the same types of comments regarding allowing Method 21 as an alternative to OGI for monitoring fugitive emissions at compressor stations as for well sites, as discussed in section VI.F.1.c. Likewise, for the same reasons as discussed earlier, we are finalizing Method 21 as an alternative to OGI for monitoring fugitive emissions components at compressor stations at a repair threshold of an instrument reading of 500 ppm or greater. We are also finalizing specific recordkeeping and reporting requirements when Method 21 is used to perform a monitoring survey. See section V.J for more details on the recordkeeping and reporting requirements.

c. Shifting of Monitoring Frequency Based on Performance

The EPA proposed shifting monitoring frequencies (ranging from annual to quarterly monitoring) based on the percentage of components that are found to have fugitive emissions during a monitoring survey. We solicited comment on the proposed monitoring scheme, including the proposed metrics of one percent and three percent to determine monitoring frequency or whether the monitoring frequency thresholds should be based on a specific number of components that are found to have fugitive emissions. In addition, the EPA solicited comment on whether a performance-based frequency or a fixed-frequency was more appropriate.

The EPA received the same comments regarding frequency of monitoring for compressor stations as for well sites, discussed in section VI.F.1.d. Likewise, for the same reasons as discussed earlier, the EPA is finalizing a fixed monitoring frequency instead of performance based monitoring.

d. Fugitive Emissions Components Repair and Resurvey

The EPA proposed that a source of fugitive emissions at compressor stations must be repaired or replaced as soon as practicable, and, in any case, no later than 15 calendar days after detection of the fugitive emissions. The EPA solicited comment on whether 15 days is the appropriate amount of time for repair of sources of fugitive emissions from compressor stations. We also solicited comment on whether 15 days is the appropriate amount of time needed to resurvey a component after it has been repaired.

The EPA received the same comments regarding the timeframe for repairs, delay of repair, and resurveys for compressor stations as for well sites, discussed in section VI.F.1.e. Likewise, for the same reasons as discussed earlier, we are finalizing 30 days for the repair of fugitive emissions sources and an additional 30 days for resurvey of the repaired fugitive emissions components.

[90] See EPA docket ID No. EPA–HQ–OAR–2010–0505.

We also are finalizing revisions to the delay of repair requirements. If a repair cannot be made due to a technical infeasibility that would require a blowdown or shutdown of the compressor station, or would be unsafe to repair by exposing personnel to immediate danger, the repair can be delayed until the next scheduled or emergency blowdown or station shutdown or within 2 years of finding the fugitive source of emissions, whichever is earlier. We believe that the likelihood of an emergency blowdown or a compressor station shutdown occurring within six months of finding fugitive emissions from a component may be low; however, it would be feasible to repair the component within a two-year timeframe, since one of above described events is likely to occur within that two-year timeframe. The owner or operator will also have to record the number and types of components that are placed on delay of repair and record an explanation for each delay of repair.

Similarly with respect to well sites, and as discussed in section VI.F.1.e, we are finalizing the use of the alternative screening procedures specified in Section 8.3.3 of Method 21 for resurveying repaired fugitive emissions components. Please see the RTC document in the public docket for further discussion.

e. Definition of ''Fugitive Emission Component''

As discussed earlier, we proposed monitoring, repair and resurvey of ''fugitive emission components,'' that apply to both well sites and compressor stations because the type of components are identical. We solicited comment on the proposed definition. The EPA received the same comments regarding the fugitive emissions component definition for compressor stations as for well sites, discussed in section VI.F.1.f. Likewise, for the same reasons as discussed earlier, we are finalizing changes to the definition to identify specific components, such as valves and flanges, that have the potential to be sources of fugitive emissions and that, when surveyed and repaired, would significantly reduce GHG and VOC emissions. This targeted list will remove the ambiguity of the proposed definition and will allow owners and operators to consistently identify fugitive emissions at compressor stations.

f. Timing of the Initial Monitoring Survey

The EPA proposed that the initial monitoring be conducted within 30 days after the initial startup of a new compressor station or modification of an existing compressor station. The EPA solicited comment on whether 30 days is an appropriate amount of time to begin conducting fugitive emissions monitoring.

Many commenters supported a longer timeframe for commencing monitoring, citing time needed to complete well ties into a compressor station that collects field gas, safety, and the relationship with other regulations, while some commenters supported the timeframe proposed. The EPA recognizes that at the time of startup of a compressor station, additional gathering lines or well tie-ins may be required. However, we also believe that, at the time of startup, the associated collection of fugitive emissions components is operational and initial monitoring can begin, even if the gathering lines or well tie-ins are incomplete, which could take several months or longer. Sources of fugitive emissions could go undetected for months if we were to allow monitoring to begin after all of the gathering lines and tie-ins were completed. Therefore, we are finalizing the proposed requirement that initial monitoring will begin after the initial startup of a compressor station instead of allowing all of the gathering lines or tie-ins to be completed before monitoring begins.

However, based on the comments received, we are concerned that the tasks required prior to conducting an initial survey would take more than the 30 days we had proposed. Because each new or modified compressor station must be covered by a monitoring plan for a company-defined area, owners and operators must visit and assess each new or modified compressor station in order to incorporate it into a newly developed or modified monitoring plan for that area. They also need to secure certified monitoring survey contractors or monitoring instruments. In addition, they need to ensure that other compliance requirements will be met, such as recordkeeping and reporting. In light of the activities described above, the EPA is requiring in the final rule that the initial survey be conducted within 60 days from startup or modification of a compressor station.

While 60 days from startup or modification of a compressor station is sufficient time to conduct the initial survey once the underlying program infrastructure is established, we recognize that the initial establishment of the required program's infrastructure and the initial round of monitoring surveys will require additional time. Most importantly, additional time is needed to secure the necessary equipment or trained personnel according to one OGI instrument manufacturer, which commented that they would need to increase production of key components for the OGI instrument to meet demand. The OGI manufacturer also indicated that they would need to scale up the number of personnel needed to provide OGI training and service of the equipment. We are concerned that currently there is not sufficient equipment and trained personnel to meet the demand imposed by this final rule in the near term. Accordingly, it will be necessary to have a window of time for trained personnel to work through this backlog. Furthermore, as previously mentioned, an owner or operator will need to develop a monitoring plan that would apply to each compressor station located within the company-defined area, which requires an assessment of each compressor station. Therefore, before a plan can be developed or modified, the owner or operator would need time to visit each compressor station within the company-defined area. In light of the above, the initial site visits and development of the monitoring plan would require a significant amount of time. Time is also needed to secure certified monitoring survey contractors or monitoring instruments. In addition, owners and operators will need to plan the logistics of the initial activities in order to comply with the requirements. This includes time to set up recordkeeping systems and to train personnel to manage the fugitive emissions monitoring program. These corporate systems are critical for submitting the notification of initial and subsequent annual compliance status.

As noted above, once programs are established and equipment supplies have caught up, well owners will be able to add additional affected facilities to existing programs and, thus, this longer timeline will not be needed. Therefore, in order to provide time for owners and operators to establish the initial groundwork of their fugitives program, we are requiring that the initial monitoring survey must take place by June 3, 2017 or within 60 days of the startup or modification of a compressor station, whichever is later. We anticipate that sources will begin to phase in these requirements as additional devices and trained personnel become available. For additional discussion, please refer to the materials in the docket.

g. Monitoring Plan

The EPA proposed that owners or operators develop a corporate-wide emissions monitoring plan that specifies the measures for locating sources and the detection technology to be used. The EPA also proposed that owners or operators develop a separate site-specific fugitive emissions monitoring plan that specifies information, such as the number of fugitive emission components for that site and for each affected facility. The EPA solicited comment on the required elements of the proposed corporate-wide monitoring plan and specifically asked for comment regarding whether the monitoring plan should include other techniques, such as visual inspections to help identify indicators of potential leaks.

As with this topic in the context of well sites, and as discussed in section VI.F.1.h, some commenters agreed with the EPA's proposal to require a corporate fugitive monitoring plan, but expressed concerns about the elements of the plan, while others objected that the proposed plan is overly prescriptive and costly, with particular concerns about including requirements for a walking path and for digital photographs. Other commenters suggested changing the scope of monitoring plans to accommodate variations in locations of contractors and equipment.

Based on the comments that we received, we are revising the fugitive emissions monitoring plan for compressor stations. We acknowledge that developing and implementing a corporate-wide monitoring plan that would be applicable to all compressor stations within a company could be problematic because compressor station configurations may differ across areas (*i.e.,* basins, fields, or districts) and what may be applicable in one area may not be relevant in another area. This would mean that a company could have to design and implement a site-specific plan for each compressor station.

We also agree that developing a site-specific plan may be overly burdensome because several gathering and boosting or transmission compressor stations may exist in a specific geographic area and have similar equipment. Using information from the Interstate Natural Gas Association of America (INGAA) and the Energy Information Administration (EIA), we estimated that, on average, compressor stations are located 70 miles apart. We also assumed that a company could monitor emissions from gathering and boosting or transmission compressor stations within a 210-mile radius of a central location. Using these assumptions, we estimated that a company could monitor seven gathering and boosting or transmission compressor stations within that company's specific geographic region. In such cases, companies would benefit from having a plan to cover all of the compressor stations within that area, as the monitoring will likely require use of the same contractors, the same company-owned monitoring instruments, or the same company personnel to perform the monitoring surveys. Allowing companies to develop one fugitive emissions monitoring plan for all of the compressors within a company-defined area would alleviate burden and provide efficiency for owners and operators.

Therefore, we are replacing the proposed corporate-wide and site-specific monitoring plan requirements with a requirement for owners or operators to develop a corporate monitoring plan for each of the company-defined areas that would cover the collection of fugitive emissions components at the compressor stations located within that company-defined area. This will allow owners and operators flexibility in developing monitoring plans for compressor stations by allowing owners and operators to determine which company-defined area can be covered under the specifications outlined in one monitoring plan, for ease of implementation and compliance. See section VI.F.1.h of this preamble for further discussion.

h. Modifications for Compressor Stations

The EPA proposed that, for the purposes of the collection of fugitive emissions monitoring and repair requirements, a compressor station is modified when a new compressor is constructed at an existing compressor station or when a physical change is made that causes an increase in the compression capacity of an existing compressor station. We received numerous comments on the compressor modification definition.

Several commenters stated that the compressor station modification definition is too vague and broad because anytime a physical modification occurred, a regulatory modification would be triggered regardless of whether there were additional emissions. Commenters also stated if a compressor station is not operating at full capacity, addition of a compressor may not necessarily increase the compressor station capacity, nor would addition of a compressor with greater horsepower (thus adding capacity) necessarily increase emissions.

At proposal, we attempted to identify distinct actions that we were confident would result in an emissions increase and would clearly mark for operators and regulators when a modification occurs. However, upon reviewing the comments, we agree that certain triggering events identified in the proposal may not result in an increase in emissions. Specifically, EPA agrees that an addition of a compressor does not result in an increase in emissions in all instances. For example, there is no emission increase when a new compressor is being installed as a replacement to an existing one. We have, therefore, made changes in the final rule to clarify when an addition of a new compressor would increase emission and therefore trigger the fugitive emission standards (*i.e.,* when it is installed as an additional compressor or if it is a replacement that is of greater horsepower than the compressor or compressors that it is replacing).

The EPA agrees that an increase in the compression capacity that is not due to the addition of a compressor that would result in an increase of the overall design capacity of the compressor station is not a modification. For example, a compressor station may have to increase the operating throughput by bringing existing compressors on-line to meet demand during peak seasons. In such a case, the compressors' capacities are already accounted for in the overall design capacity for the compressor station, and bringing them on-line would not increase the overall design capacity nor would it increase the potential emissions of the compressor station. Therefore, we are not finalizing that an increase in compression capacity is a modification.

Commenters also indicated that the addition of a new compressor at an existing compressor station should not trigger a fugitive emissions monitoring program for the entire compressor station but, should only apply to the new compressor and its associated components. We disagree that the addition of a compressor at an existing compressor station should not trigger a fugitive emissions monitoring program for the entire compressor station. We have clarified that the installation of a compressor will only trigger the fugitive monitoring requirements if it is installed as an additional compressor or if it is a replacement that is of greater horsepower than the compressor or compressors that it is replacing. In this case, the design capacity and potential emissions of the compressor station would increase. Unlike the affected facilities for purposes of standards for centrifugal and reciprocating compressors themselves, the affected facility for purposes of the fugitive emission requirements is the collection of fugitive emissions components at a compressor station, not the fugitive emissions components associated with a single compressor. Therefore, if a compressor is added to an existing compressor station, the entire compressor station is subject to the fugitive emissions monitoring program.

Therefore, we are finalizing a definition that we are confident identifies actions that increase emissions and achieves our original goal of having clearly identifiable criteria that can be easily recognized by operators and regulators. We are finalizing that a modification to a compressor station occurs when a compressor is added to a compressor station or if one or more compressors is replaced with one or more compressors with a greater total horsepower.

i. Provision for Emerging Technology

Pursuant to CAA section 111(h)(3), we are establishing in the final rule a process for the Agency to permit the use of innovative technology for reducing fugitive emissions at well sites and/or compressor stations. For a detailed discussion, please see section VI.F.1.i.

G. Equipment Leaks at Natural Gas Processing Plants

For equipment leaks at natural gas processing plants, the EPA received a total of seven comments addressing issues such as the definition of natural gas processing plant and whether OGI may be used in place of Method 21. We reviewed the comments received and determined to finalize the standard for equipment leaks at natural gas processing plants as proposed. Specifically, the final rule requires NSPS part 60, subpart VVa level of control, including a detection limitation of 500 ppm for certain pieces of equipment. Please see the TSD and RTC documents in the public docket for further discussion.

H. Reconsideration Issues Being Addressed

To address numerous items on which we granted reconsideration, we proposed amendments to subpart OOOO and solicited comment on certain topics that would also impact the new NSPS requirements. With some revisions based on our consideration of public comment, the EPA is finalizing certain reconsideration amendments. These amendments address: Storage vessel control device monitoring and testing provisions; initial compliance requirements for bypass devices; recordkeeping requirements for repair logs for control devices failing a visible emissions test; clarification of the due date for the initial annual report under the 2012 NSPS; flare design and operation standards; LDAR for open-ended valves or lines; compliance period for LDAR for newly affected units; exemption to notification requirement for reconstruction; disposal of carbon from control devices; the definition of capital expenditure; and continuous control device monitoring requirements for storage vessels and centrifugal compressor affected facilities. This section identifies specifically what the EPA proposed, identifies the regulatory text changes from proposal, and states how the EPA is finalizing these provisions.[91] Please see the TSD and RTC documents in the public docket for further discussion.[92]

1. Storage Vessel Control Device Monitoring and Testing Provisions

The EPA proposed regulatory text changes to address performance testing and monitoring of control devices used for new storage vessel installations and centrifugal compressor emissions, specifically relating to in-field performance testing of enclosed combustors. The EPA specifically proposed to revise the limit for total organic carbon (TOC) concentration in the exhaust gases at the outlet of the control device from 20 ppmv to 600 ppmv as propane on a dry basis corrected to 3 percent oxygen, a value that more appropriately reflects 95 percent control of VOC inflow to control devices. The EPA also proposed initial and ongoing performance testing for any enclosed combustors used to comply with the emissions standard for an affected facility and whose make and model are not listed on the EPA Oil and Natural Gas Web site (*http://www.epa.gov/airquality/oilandgas/implement.html*) as those having already met a manufacturer's performance test demonstration. The proposal stated that performance testing of combustors not listed at the above Web site would be conducted on an ongoing basis, every 60 months of service, and monthly monitoring of visible emissions from each unit would also be required.

Additionally, the EPA proposed amendments to make the requirements for monitoring visible emissions consistent for all enclosed combustion units. Specifically, the EPA proposed to amend 40 CFR 60.5413(e)(3) to require monthly 15-minute period observations using EPA Method 22.

Based on information submitted through the public comment process, the EPA has identified four necessary revisions for the final storage vessel provisions. First, commenters provided information to the EPA concerning the use of 600 ppmv as propane as appropriately reflecting 95 percent control of VOC inflow to control devices. After an evaluation of the comments, we agreed that the EPA's assumption about the ratio of fuel to combustion air was incorrect, making the proposed 600 ppmv as propane value incorrect. The 600 ppmv as propane value was derived in the memorandum dated June 2, 2015,[93] which discusses the background for the § 60.5412(a)(1)(ii) TOC exhaust gas standard for combustion control devices to control VOC emissions from oil and gas affected facilities. While this analysis reflects the destruction of hydrocarbons compared to the concentration of hydrocarbon in the inlet fuel, our analysis did not take into account any in-stack dilution represented by the introduction of combustion air or the correction of that air to 3 percent oxygen. Since hydrocarbon combustion requires approximately a ratio of 12:1 input of combustion air to hydrocarbon, the outlet concentration of TOC would be adjusted downward to 275 parts per million by volume on a wet basis (ppmvw), as propane, at 3 percent O_2. The final rule corrects this concentration at § 60.5412(a)(1)(ii), and the EPA has appended the memo in the public docket with this adjustment.

Second, the EPA is finalizing amendments to make the requirements for monitoring of visible emissions consistent for all enclosed combustion units. Prior to the proposal, enclosed combustors that met the manufacturer's performance test requirement were to conduct quarterly observations for visible smoke emissions employing section 11 of EPA Method 22 for a 60-minute period. Petitioners suggested it would ease implementation to adjust the frequency and duration to monthly 15-minute EPA Method 22 tests, which is currently required for continuous monitoring of enclosed combustors that are not manufacturer tested. The EPA agrees with the petitioners. This revision will result in consistent requirements to all enclosed combustors, which will make compliance easier for owners and operators. Because both monitoring requirements ensure compliance of the enclosed combustors, and having the

[91] 80 FR 56645, September 18, 2015.

[92] *See* EPA docket ID No. EPA–HQ–OAR–2010–0505.

[93] See Docket ID No. EPA–HQ–OAR–2010–0505–4907.

same requirement would ease implementation burden, we are finalizing amendments to §§ 60.5413(e)(3) and 60.5415(b)(2)(vii)(B) to require monthly 15-minute period observations using EPA Method 22 Test, as suggested by the petitioner.

The EPA proposed requirements for determining applicability for new storage tanks that replace existing tanks. Commenters provided alternative text indicating how the meaning of the regulation was difficult to discern. The EPA considered the suggested text and agrees that amending this section will make the requirements for compliance easier to understand. The amended language has been finalized in § 60.5365(e)(4).

Fourth, the EPA received comments requesting removal of the requirement that certain devices that route emissions to processes must reduce emissions by 95 percent and instead be written to be consistent with § 60.5411a(c), which requires that process devices must operate 95 percent of the year or greater. Upon further reflection, the EPA determined that, because § 60.5395a(a) clearly requires that affected sources (except those with uncontrolled emissions below 4 tons per year (tpy)) must reduce VOC emission by 95 percent, it is not necessary to further prescribe the level of reduction to be achieved when emissions are routed to a process. The EPA has therefore removed such specification in § 60.5395a(b)(1) in the final rule. As finalized, this specific provision relative to control requirements is the same for centrifugal compressors, pneumatic pumps, and storage vessel affected facilities routing to a process.

2. Initial Compliance Requirements for Bypass Devices

The EPA proposed to amend § 60.5416(c)(3)(i) to include notification via remote alarm to the nearest field office in order to maintain consistency with previous amendments. The EPA proposed to require both an alarm at the bypass device and a remote alarm. The EPA proposed similar amendments to parallel requirements at § 60.5411(a)(3)(i)(A) for closed vent systems used with reciprocating compressors and centrifugal compressor wet seal degassing systems. At proposal to amend subpart OOOO, EPA changed ''or'' to ''and'' under subpart OOOO at §§ 60.5411(a)(3)(i)(A) and 60.5411(c)(3)(i)(A), which would have required that both an audible and remote alarm be installed on a bypass device with the potential to vent to the atmosphere. One commenter pointed out that the requirements would be applied retroactively, as the EPA changed the requirements in subpart OOOO as well as subpart OOOOa. The EPA agrees with the commenter that our intent was not to create a retroactive requirement by revising subpart OOOO. The EPA is therefore not finalizing the changes to subpart OOOO, § 60.5411(a)(3)(i)(A), or § 60.5411(c)(3)(i)(A).

Although we are not finalizing both audible and remote alarm requirements in subpart OOOO, the EPA disagrees that the requirement for remote notification is unreasonable and is therefore preserving the option as an alternative to an audible alarm. The EPA notes that either requirement is restricted to those bypass devices that vent to the atmosphere, not bypass devices (such as some pressure relief devices) that are required to be routed through closed vent systems to control devices. The EPA proposed to require both types of notification in subpart OOOOa because of the diverse nature of facilities that will use them. While an audible alarm may be sufficient at facilities that have personnel present on a continuous basis, not all affected facilities are at continuously-manned locations. An audible alarm on a bypass at a remote location that is visited only on a schedule by maintenance personnel would likely alert no one authorized to take action on the audible alarm until such time as the maintenance personnel arrive, which according to industry, may be a considerable time. The EPA agrees that the logistical requirements may need to be resolved in some instances, and is therefore finalizing the requirements in subpart OOOOa to be the same in substance as the requirements in subpart OOOO, which allow for the operator to choose one form of alarm or the other. Section 60.5416a(c)(3)(i) was revised to match the promulgated regulatory language in § 60.5416(c)(3)(i) of OOOO for consistency.

3. Recordkeeping Requirements for Repair Logs for Control Devices Failing a Visible Emissions Test

The EPA proposed that the recordkeeping requirements include the repair logs for control devices failing a visible emissions test as required by the rule. Petitioners noted that the recordkeeping requirements of § 60.5420(c) do not include the repair logs for control devices failing a visible emissions test required by § 60.5413(c). We agree that these recordkeeping requirements should be listed and are finalizing them at § 60.5420(c)(14).

4. Due Date for Initial Annual Report

The EPA did not propose regulatory text to amend the rule; rather, the EPA stated in the preamble to the proposed rule that we will consider any initial annual report submitted no later than January 15, 2014 to be a timely submission. All subsequent annual reports must be submitted by the correct date of January 13 of the year.

5. Flare Design and Operation Standards

The EPA proposed to remove the provision of Table 3 in subpart OOOO that exempts flares from complying with the requirements for the design and operation of flares under 40 CFR 60.18 of the General Provisions. By removing the exemption from the General Provisions of subpart OOOO, this clarifies that flares used to comply with subpart OOOO are subject to the design and operation requirements in the general provisions.

Comments on our proposal focused on support for the use of pressure-assisted flares. Pressure-assisted flares are designed to operate with high velocities up to sonic velocity conditions (*e.g.,* 700 to 1,400 feet per second for common hydrocarbon gases). In order to evaluate the use of pressure-assisted flares by the oil and natural gas industry and determine whether to develop operating parameters for pressure-assisted flares for purposes of subparts OOOO and subpart OOOOa, the EPA solicited comment on where in the source category, under what conditions (*e.g.,* maintenance), and how frequently pressure-assisted flares are used to control emissions from an affected facility, as defined within this subpart. From comments to our proposal, the EPA understands that there may be affected facilities that use pressure-assisted flares (*e.g.,* sonic flares) to control emissions from certain activities; however, the EPA now understands that an affected facility storage vessel, pneumatic pump, or centrifugal or reciprocating compressor would not use a pressure-assisted flare for control. The affected facility could be routed by closed vent system to a low pressure flare, which can comply with the velocity requirements of 40 CFR 60.18. The EPA received information showing that certain configurations have separate flare tips that accommodate high pressure and low pressure. The EPA understands that a flare configured this way would be able to meet § 60.18 on the low pressure side, which would be appropriate for compliance with these standards. Given these facts, the EPA is finalizing the rule as proposed, because no regulatory amendment appears necessary for such flares to comply with the proposed requirements.

6. Leak Detection and Repair (LDAR) for Open-Ended Valves or Lines

In the preamble to the final 2012 rule, the EPA stated that subpart VVa lowered the concentration limit defining a leak from 10,000 ppm to 500 ppm. The EPA's action did not revise subpart VVa, but rather changed the application of leak detection and repair provisions by making the LDAR standards of subpart VVa applicable to affected units subject to LDAR under subpart OOOO if the concentration emanating from a leak is 500 ppm or greater. The EPA further stated that monitoring requirements from subpart VVa applied to pumps, pressure relief devices, and open-ended valves or lines at units affected by LDAR under subpart OOOO. Although the preamble may have obscured the issue, we clarify here that the monitoring provisions of subpart VVa applicable to affected units of subpart OOOO do not extend to open-ended valves or lines. Given this clarification of preamble language, the EPA can identify no need to modify the regulatory language in response to this petition.

7. Compliance Period for LDAR for Newly Affected Units

An issue was raised in an administrative petition that the EPA did not adequately respond to a comment on the 2011 proposed NSPS regarding the compliance period for the LDAR requirements for on-shore natural gas processing plants. The commenter requested that the EPA include in subpart OOOO a provision similar to subpart KKK, 40 CFR 60.632(a), which allows a compliance period of up to 180 days after initial start-up. The commenter was concerned that a modification at an existing facility or a subpart KKK regulated facility could subject the facility to subpart OOOO LDAR requirements without adequate time to bring the whole process unit into compliance with the new regulation. We clarify that subpart OOOO, as promulgated in 2012, already includes a provision similar to subpart KKK, § 60.632(a), as requested in the comment. Therefore, the EPA has determined there is no need to modify the current regulations.

8. Exemption to Notification Requirement for Reconstruction

The EPA received an administrative petition that raised the issue that notification of reconstruction requirements under § 60.15(d) is unnecessary for some affected facilities. After consideration, the EPA agrees that some notifications are unnecessary because the EPA specifies notification of reconstruction for affected unit pneumatic controllers, centrifugal compressors, reciprocating compressors, and storage vessels under § 60.5410a and § 60.5420a, in lieu of the general notification requirement in § 60.15(d). To make this change effective, the EPA has noted this change in the explanatory comments in Table 3 reflecting that § 60.15(d) does not apply to affected facility pneumatic controllers, centrifugal compressors, reciprocating compressors and storage vessels in subpart OOOO. The EPA has determined to finalize these amendments as proposed.

9. Disposal of Carbon From Control Devices

The EPA re-proposed provisions for management of waste from spent carbon canisters that were finalized in § 60.5412(c)(2) of the 2012 NSPS to allow for comment. The EPA received no comment to the re-proposal. The EPA has determined to finalize these amendments as proposed.

10. The Definition of Capital Expenditure

The EPA proposed to specifically define the term ''capital expenditure'' in subpart OOOO. In this proposed definition, the EPA updated the formula to reflect the calendar year that subpart OOOO was proposed, as well as specified that the B value for subpart OOOO is 4.5. These updates are necessary for proper calculation of capital expenditure under subpart OOOO. The EPA has determined to finalize these amendments as proposed. Please refer to the RTC document in the public docket for this rulemaking for further discussion.

11. Tanks Associated With Water Recycling Operations

The EPA solicited comment in the proposed rule to remove tanks that are used for water recycling from potential NSPS applicability and on approaches that could be taken to amend the definition of ''storage vessel.'' Commenters requested that the EPA remove water tanks that are primarily used for water recycling from subpart OOOOa applicability. Commenters discussed that large storage tanks encourage large scale water recycling and are expected to reduce fresh water usage primarily in the Permian Basin. After reviewing the public comments, the EPA agrees that certain large water recycling vessels should be exempt from affected facility status for storage vessels because EPA did not intend such vessels to be affected facility storage vessels under subpart OOOO or OOOOa. By exempting such vessels, EPA will not create a disincentive for recycling of water for hydraulic fracturing. Therefore, the final rule exempts water recycling vessels that receive water that has been through separation, and are much larger than the storage vessels generally intended to be regulated by subparts OOOO and OOOOa for VOC emissions. The EPA has included the exemption language at § 60.5365(e)(5) and § 60.5365a(e)(5) in the final rule.

12. Continuous Control Device Monitoring

The EPA proposed under § 60.5417 to add continuous control device monitoring requirements for storage vessels and centrifugal compressor affected facilities. The EPA received comments indicating that to impose this requirement on affected facilities under subpart OOOO may make such requirements retroactive, given the time between the original proposal for subpart OOOO and the proposal of the additional requirements. To avoid this possibility, the EPA will not finalize the change proposed to subpart OOOO, § 60.5417(h)(4).

I. Technical Corrections and Clarifications

The EPA is finalizing technical corrections and clarifications intended to provide clarity, improve implementation, and update procedures. This section identifies each correction and the rationale for these changes. Please see the TSD and RTC documents in the public docket for further discussion.[94]

1. The EPA discovered drafting errors in § 60.5412a(d)(1)(iv)(A), § 60.5412a(d)(2) and § 60.5415a(e)(3) that required control of methane from storage vessels. As discussed in the preamble and the TSD for the proposed rule, the EPA did not consider reduction of methane emissions from storage vessels. Therefore, the reference to controlling storage vessel methane emissions in the proposed regulatory text in the above provisions was a drafting error. In correction, the EPA is removing ''methane and'' from these three provisions because methane control is not required for storage vessels under subpart OOOOa.

2. A commenter noted that EPA had omitted a clear deadline by which newly constructed, reconstructed, or

[94] See EPA docket I.D. No. EPA–HQ–OAR–2010–0505.

modified storage vessels that receive liquids from sources other than hydraulically fractured wells must make their potential to emit determination, in § 60.5365a(e)(1). The commenter presumed, correctly, that the omission was inadvertent, stating that ''Presumably, EPA intends that such tanks with potential VOC emissions greater than 6 tons per year would be subject to the rule.'' We have more clearly specified the deadline.

3. We removed the requirement in § 60.5375a(a)(2) that all salable gas recovered from a well completion be routed as soon as practicable to a gathering line. This requirement was duplicative of the provisions of paragraph (a)(1) of the same section.

4. We revised § 60.5420a(b)(4)(i) to include the provision that gas recovered from reciprocating compressors could also be routed to a process as an alternative to replacing rod packing no later than on or before 26,000 hours of operation or 36 months. We additionally corrected an error that identified a wrong initial startup period. This correction consists of removing ''since [insert date 60 days after publication of final rule in the **Federal Register**].'' This correction was also made in § 60.5420a(c)(3)(i) and § 60.5415a(c)(1).

5. We revised the requirements in § 60.5417a for heat sensing monitoring devices on pilot flames to clarify that these devices are not subject to calibration, quality assurance and quality control requirements. While we intended for these devices to monitor continuously, we did not intend to place all of the requirements for continuous parameter monitoring systems on these devices. We also revised the language in § 60.5417a(e) and § 60.5417a(g) to indicate that heat sensing is not a daily average and that a deviation occurs when the device fails to indicate the presence of a pilot flame.

6. We revised the language in § 60.5417a(f)(1)(iii) for monitoring inlet gas flow rate on control devices tested by the manufacturer. We did not intend for owners or operators to have to continuously achieve a minimum inlet gas flow rate. We have revised the requirement to indicate that there is only a limit on the maximum gas inlet flow rate to the device. We also revised the language in § 60.5417a(d)(1)(viii)(A) to indicate that the accuracy requirement is at the maximum flow rate.

7. We revised the language in § 60.5413a(d)(11)(iii) to indicate that manufacturers must demonstrate a destruction efficiency of 95 percent for total hydrocarbons (THC), as propane. This requirement previously stated that the manufacturer must demonstrate a destruction efficiency of 95 percent for VOC and methane. The revised language aligns more accurately with the testing requirements in the rule. Additionally, as these units are burning propene during the test, it would be impossible to demonstrate a destruction efficiency of methane. As methane is a one-carbon, single-bonded compound, it is more easily destructed than propene, a double-bonded compound, and thus, the destruction efficiency should be just as high or higher for methane than for the THC measured during the performance test.

8. We revised the testing language in § 60.5413a(b) in order to make it clearer for compliance purposes. The proposed language failed to clearly identify the number of runs or the length of runs expected for each performance test. Additionally, the calculations did not properly align with the specified methods. Section 60.5412a(d)(1)(i) has no subsections. The reference to ''percent reduction performance requirement'' in the referring section 60.5413a(b)(3) indicates that the cross reference should refer to section 60.5412a(d)(1)(iv)(A), which contains the percent reduction required.

9. We revised the language in § 60.5395a(a) to clarify that owners and operators must comply with the requirements of § 60.5395a(a)(1). The proposed language could have been interpreted to mean that compliance with § 60.5395a(a)(1) was not required if owners or operators complied with § 60.5395a(a)(3); however, it would be impossible to comply with § 60.5395a(a)(3) without first determining the potential for VOC emissions, as required by § 60.5395a(a)(1). We also further clarified when owners and operators must comply with the requirements of § 60.5395a(a)(2) and when they may comply with the requirements of § 60.5395a(a)(3).

10. We revised the language in § 60.5420a(b)(9)(i), § 60.5420a(b)(11), § 60.5422a(a), and 60.5423a(b) to update the Web site address for the Electronic Reporting Tool (ERT). We have also clarified that if the CEDRI form is not available at the time that a report is due, we do not intend for owners or operators to submit forms electronically through CEDRI until the form has been available for 90 days. We are also clarifying that this only applies to subsequent reports; owners or operators would not be required to enter previous reports into CEDRI once the form is available. While similar language was proposed, we realize that the previous language did not fully capture our intent.

11. We revised the language in § 60.5412a(c)(2)(iii) to correct a drafting error. The proposed language lists the types of units in which owners or operators must regenerate or reactivate spent carbon. The proposed language stated the unit must be operating emission controls in accordance with an emissions standard for VOC under another subpart in 40 CFR part 60 or this part, which is redundant. The language has been revised to state part 63 or this part. We also removed § 60.5412a(c)(2)(ii), as we do not believe that owners or operators would be able to regenerate or reactivate spent carbon in accordance with this section, as there are no requirements in this section for that activity. Finally, we removed the phrase ''thermal treatment'' in front of unit in § 60.5412a(c)(2)(i) and (iii) as the phrase ''thermal treatment unit'' is not defined.

12. We revised the language in § 60.5412a(c)(2)(iv) through (vii) and § 60.5413a(a)(4) and (5) to reconcile the fact that most hazardous waste combustion units are subject to the requirements of 40 CFR part 63 subpart EEE. While our intent was to encompass all hazardous waste incinerators, boilers and industrial furnaces in these requirements, referencing only 40 CFR parts 264, 265, 266 and 270 may have inadvertently excluded units.

13. We revised the language in § 60.5413a(b)(5)(ii)(B) to more clearly identify the continuing compliance obligations for units exempt from periodic testing.

14. We revised the TOC emission rate limit in § 60.5412a(a)(1)(ii) and § 60.5412a(d)(1)(iv)(B) to be consistent with the changes to the limit in 40 CFR part 60 subpart OOOO. For more explanation on this topic, see the discussion on reconsideration issues in section VI.H of this preamble. We also revised the TOC limit to be on a wet basis, as these units will be tested with Method 25A, which provides measurement data on a wet basis. While we note that compressors must control both VOCs and methane to at least 95 percent, the calculated limit reflects 95 percent control of VOC inflow to control devices. Because methane is the simplest carbon compound, it is very easy to destroy through combustion. Ensuring 95 percent destruction of VOCs will guarantee greater than 95 percent destruction of methane.

15. We revised the wording of § 60.5365(e)(4) and 60.5365a(e)(4) at the request of commenters seeking clearer direction on the applicability of standards to storage vessels returning to

service. Since the re-wording does not change the meaning or requirements of the section, the revisions have been made to both subparts OOOO and OOOOa for consistency.

16. We corrected the cross reference in section 60.5415(c)(4) from § 60.5411(a) to section 60.5416(a) and (b), and in § 60.5415a paragraph (c)(4) from section 60.5411a(a) to § 60.5416a(a) and (b).

17. We corrected language in in § 60.5420(c)(6) to include reciprocating compressors.

18. We adjusted the language in § 60.5412(d)(1)(iv)(C), § 60.5412a(a)(1)(iii) and § 60.5412a(d)(1)(iv)(C). This language allowed operation of the control device at a minimum temperature of 760°Celsius, if the control device was able to demonstrate a uniform combustion temperature during the performance test. In our response to comments on the August 23, 2011 proposed rule, we agreed with commenters that uniform combustion profiles are difficult to obtain due to flame zone mixing and heat transfer. In response to that comment, we revised the language in 40 CFR part 63 subpart HH. We have now revised the language in 40 CFR part 60 subparts OOOO and OOOOa to mimic the language in 40 CFR part 63 subpart HH. We believe that this change is necessary as we do not believe that owners or operators will be able to demonstrate a uniform combustion zone temperature, nor have we defined what it means to have a uniform combustion zone temperature (*e.g.*, the number of measurement points necessary, the agreement between points, etc.). Additionally, § 60.5412(d)(1)(iv)(C), § 60.5412a(a)(1)(iii) and § 60.5412a(d)(1)(iv)(C) previously referenced performance testing in accordance with § 60.5413 and § 60.5413a, but it was unclear what the performance testing obligations were. We believe the revised language will allow owners and operators to more easily comply with this requirement.

19. We added language to § 60.5412(d) and § 60.5412a(d) to make our intent clear that flares are acceptable control devices for storage vessels and to identify the design requirements for flares. We also revised language in § 60.5415a(b)(2)(vii) to clearly identify the continuing compliance requirements for flares.

20. We adjusted the language in § 60.5413a(b)(5)(ii)(A) and § 60.5417a(d)(1)(viii) to add a second compliance option for control device models tested under § 60.5413a(d). We are allowing owners and operators an option to retest these units every five years in lieu of continuously monitoring the gas flow rate. Owners and operators must still ensure they are not overwhelming the control device by using a control device that can handle the maximum flow rate at the site.

21. We added language to § 60.5417a(a) to identify the continuing compliance requirements for enclosed combustion devices that are not specifically identified in § 60.5417a(d).

22. In preparation of the final rule, EPA discovered an error in both subpart OOOO and the proposed subpart OOOOa. Specifically, they fail to include a general duty to minimize emissions. As the EPA clarified during the 2012 NSPS rulemaking, ''[t]he general duty is applicable to a source at all times.'' [95] Therefore, the absence of this provision in subpart OOOO and the proposed subpart OOOOa was an error, which is being corrected in these final rules at § 60.5370 and § 60.5370a.

J. Final Standards Reflecting Next Generation Compliance and Rule Effectiveness

We are finalizing certain standards that are reflecting EPA's Next Generation Compliance and rule effectiveness strategies. Based on our consideration of the comments received, we are finalizing some aspects as proposed while, for others, we have made a number of changes to the proposed standards. We have the opportunity to expand transparency by making the information we have more accessible and by making new information, obtained from advanced emissions monitoring and electronic reporting, publicly available. We are finalizing an electronic reporting requirement, via the EPA's CDX.

Other aspects of the final rule will maximize regulatory compliance, such as clear applicability of the final rule (*e.g.*, in revisions to modification criteria) and provide incentives for inherently low-emitting equipment (*e.g.*, solar pumps at gas plants are not affected facilities). Advances in technology additionally promote compliance by enhancing a ''visibility'' factor; this rule builds on such Next Generation strategies, by including measures involving the use of digital picture reporting and OGI technology. In lieu of independent third party verification for closed vent system design, we are finalizing a qualified professional engineer certification for certain issues. For example, as discussed in section VIII of this preamble, in response to comment, we are providing that a pneumatic pump that cannot be connected to an existing control device due to technical infeasibility does not have to meet this requirement. However, we will require that the source make this determination through use of a professional engineer certification. We are finalizing the use of OGI technology as a method for detecting fugitive emissions at well sites and compressor station sites. With the exception of ''clear applicability'', ''incentives for inherently low-emitting equipment'' and ''OGI technology for monitoring fugitive emissions'', which are discussed elsewhere in this preamble, this section identifies the rationale to the regulatory text changes from proposal and states how the EPA is finalizing these provisions. For additional details, please refer to section VIII, the TSD, and the RTC supporting documentation in the public docket.

1. Electronic Reporting

Through electronic reporting, or e-reporting, paper reporting is replaced by standardized, Internet-based, electronic reporting to a central repository using specifically developed forms, templates, and tools. E-reporting is not simply a regulated entity emailing an electronic copy of a document to the government but, also a means to make collected information easily accessible to the public and other stakeholders.

On March 20, 2015, the EPA proposed the ''Electronic Reporting and Recordkeeping Requirements for New Source Performance Standards'' (80 FR 15099, March 20, 2015). If adopted, the rule would revise the part 60 General Provisions and various NSPS subparts in part 60 of title 40 of the Code of Federal Regulations (CFR) to require affected facilities to submit specified air emissions data reports to the EPA electronically and to allow affected facilities to maintain electronic records of these reports. This proposed rule focuses on the submission of electronic reports to the EPA that provide direct measures of air emissions data such as performance test reports, performance evaluation reports, summary and excess emission reports and subpart specific reports that are similar in nature to these reports.

Subpart OOOO is one of the rules potentially affected by this rulemaking. When promulgated, in addition to electronically reporting the results of performance tests, which is already a requirement, a requirement to report the annual reports required in § 60.5420(b), the semiannual reports required in § 60.5422 and the excess emissions reports required in § 60.5423(b) would

[95] See RTC document in EPA Docket I.D. No. EPA–HQ–OAR–2010–0505–4546.

be added to subpart OOOO. The owner or operator would be required to use the appropriate electronic form in CEDRI for the subpart or an alternate electronic file format consistent with the form's extensible markup language (XML) schema. If the reporting form specific to the subpart is not available at the time that the report is due, the owner or operator would submit the report to the Administrator at the appropriate address listed in § 60.4 of the General Provisions. The owner or operator would begin submitting reports electronically with the next report that is due once the electronic form has been available for at least 90 days. The EPA is currently working to develop the form for subpart OOOO.

In the proposal for subpart OOOOa, the EPA included the same electronic reporting requirements for subpart OOOOa that were included for subpart OOOO in the March 2015 proposal. The EPA is finalizing the requirement to report certain performance test reports, excess emission reports, annual reports and semiannual reports electronically through the EPA's CDX using the CEDRI. The EPA believes that the electronic submittal of the reports addressed in this rulemaking will increase the usefulness of the data contained in those reports, is in keeping with current trends in data availability, will further assist in the protection of public health and the environment, and will ultimately result in less burden on the regulated community. Electronic reporting can also eliminate paper-based, manual processes, thereby saving time and resources, simplifying data entry, eliminating redundancies, minimizing data reporting errors, and providing data quickly and accurately to the affected facilities, air agencies, the EPA and the public.

The EPA Web site that stores the submitted electronic data, WebFIRE, will be easily accessible to everyone and will provide a user-friendly interface that any stakeholder can access. By making the records, data and reports addressed in this rulemaking readily available, the EPA, the regulated community and the public will benefit when the EPA conducts its CAA-required reviews. As a result of having reports readily accessible, our ability to carry out comprehensive reviews will be increased and achieved within a shorter period of time.

The EPA anticipates fewer or less substantial information collection requests (ICRs) in conjunction with prospective CAA-required reviews may be needed, resulting in a decrease in time spent by industry to respond to data collection requests. The EPA also expects the ICRs to contain less extensive stack testing provisions, as we will already have stack test data electronically. Reduced testing requirements would be a cost savings to industry. The EPA should also be able to conduct these required reviews more quickly. While the regulated community may benefit from a reduced burden of ICRs, the general public benefits from the Agency's ability to provide these required reviews more quickly, resulting in increased public health and environmental protection.

Air agencies will benefit from more streamlined and automated review of the electronically submitted data. Having reports and associated data in electronic format will facilitate review through the use of software "search" options, as well as the downloading and analyzing of data in spreadsheet format. The ability to access and review air emission report information electronically will assist air agencies to more quickly and accurately determine compliance with the applicable regulations, potentially allowing a faster response to violations that could minimize harmful air emissions. This benefits both air agencies and the general public.

For a more thorough discussion of electronic reporting, see the discussion in the preamble of the March 2015 proposal. In summary, in addition to supporting regulation development, control strategy development, and other air pollution control activities, having an electronic database populated with performance test data will save industry, air agencies, and the EPA significant time, money, and effort while improving the quality of emission inventories, air quality regulations, and enhancing the public's access to this important information.

2. Digital Picture Reporting as an Alternative for Well Completions ("REC PIX") and Manufacturer Installed Control Devices

The EPA is finalizing digital picture reporting as an alternative for well completions and manufacturer installed control devices as proposed. Specifically, the final rule allows digital picture reporting as an alternative for well completions ("REC PIX") and manufacturer installed control devices. These alternative reporting options provide flexibility for owners and operators, provide enhanced "visibility" for regulators, and take advantage of the advances of the digital age with the ability to capture geospatial accuracy at any location.

Digital picture reporting as an alternative for well completions ("REC PIX") reflects the 2012 NSPS. As with the 2012 NSPS, we continue to promote an optional mechanism by which owners and operators could streamline annual reporting of well completions by using a digital camera to document that a well completion was performed in compliance with subpart OOOOa. Although we understand that commenters have concerns about the amount of electronic storage capability necessary to store digital pictures, we believe that by allowing either the REC PIX or the elements required under the recordkeeping requirements for well completions, the owner or operator may determine what is most advantageous for their company. Should an owner or operator choose to submit the REC PIX, the REC PIX must consist of a digital photograph of the REC equipment in use, with the date and geospatial coordinates shown on the photographs. These photographs must be submitted with the next annual report, along with a list of well completions performed with identifying information for each well completed.

Digital picture reporting as an alternative for manufacturer installed control devices provides further opportunity and flexibility to owners and operators to advance data capture to ensure that compliance practices are in effect. This alternative recordkeeping and reporting option is allowed specifically for centrifugal compressors and storage vessels routed to control devices, where the control device used is one tested in accordance with the manufacturer testing procedures in the rule and is posted to the EPA Oil and Gas page. In lieu of a written record with the location of the centrifugal compressor or storage vessel and its associated control device in latitude and longitude, the digital picture alternative must have the date the photograph was taken and the latitude and longitude of the centrifugal compressor and control device or storage vessel and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital picture, the digital picture 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. Furthermore, as discussed in section VI.F of this preamble, digital pictures and frame captures will help ensure that OGI for fugitive emissions is being performed properly.

3. Certification of Technical Infeasibility of Connecting a Pneumatic Pump to an Existing Control Device

In response to comment, the final rule requires that a new, modified, or reconstructed pneumatic pump be routed to an existing control device or process onsite, unless the owner or operator obtains a certification that it is technically infeasible to do so. The EPA understands that some factors such as capacity of the existing control device and back pressure on the exhaust of the pneumatic pump imposed by the closed vent system and control device can contribute to infeasibility of routing a pneumatic pump to an existing control device onsite. Due to the various scenarios that could make routing a pneumatic pump to an onsite control device or process technically infeasible, we do not think we could prescribe a specific set of criteria or factors that must be considered for making such determination that could capture all such circumstances. However, we want to ensure that the owner or operator has effectively assessed these factors before making a claim of infeasibility. To that end, we have included provisions in the final rule to require certification by a qualified professional engineer of such technical infeasibility. In addition, we are requiring that the owner or operator maintain records of that certification for a period of five years.

4. Professional Engineer Design of Closed Vent Systems

It is the EPA's experience, through site inspections and interaction with the states, that closed vent systems and control devices for storage vessels and other emission sources often suffer from improper design or inadequate capacity that results in emissions not reaching the control device and/or the control device being overwhelmed by the volume of emissions. Either of these conditions can seriously compromise emissions control and can render the system ineffective. We also discussed the issue in the September 2015 Compliance Alert ''EPA Observes Air Emissions from Controlled Storage Vessels at Onshore Oil and Natural Gas Production Facilities'' (See *https://www.epa.gov/sites/production/files/2015-09/documents/oilgascompliancealert.pdf*).

We believe it is important that owners and operators make real efforts to provide for proper design of these systems to ensure that all the emissions routed to the control device reach the control device and that the control device is sized and operated to result in proper control. As a result, we have included in the final rule provisions for certification by a qualified professional engineer that the closed vent system is properly designed to ensure that all emissions from the unit being controlled in fact reach the control device and allow for proper control.

Although the final rule does not include requirements for specific criteria for proper design, the EPA believes there are certain minimum design criteria that should be considered to ensure that the closed vent and control device system are designed to meet the requirements of the rule; *i.e.,* the closed vent system must be capable of routing all gases, vapors, and fumes emitted from the affected facility to a control device or to a process that meets the requirements of the rule.

Furthermore, because other emissions may be collected into the closed vent system and routed to the control device, these design criteria include consideration of the contribution of these additional emissions to ensure proper sizing and operation. The minimum design elements include, but are not limited to, based on site-specific considerations:

1. Review of the Control Technologies to be Used to Comply with §§ 60.5380a and 60.5395a.

2. Closed Vent System Considerations:

a. Piping—

i. Size (include all emissions, not just affected facility);

ii. Back pressure, including low points which collect liquids;

iii. Pressure losses; and

iv. Bypasses and pressure release points.

3. Affected Facility Considerations:

a. Peak Flow from affected facility, including flash emissions, if applicable; and

b. Bypasses, pressure release points.

4. Control Device Considerations:

a. Maximum volumetric flow rate based on peak flow, and

b. Ability to handle future gas flow.

K. Provision for Equivalency Determinations

In recent years, certain states have developed programs to control various oil and gas emission sources in their own states. Due to the differences in the sources covered and the requirements, determining equivalency through direct comparison of the various state programs with the NSPS has proven to be difficult. We also did not find that any state program as a whole would reflect what we have identified as the BSERs for all emissions sources covered by the NSPS. In any event, federal standards are necessary to ensure that emissions from the oil and natural gas industry are controlled nationwide.

However, depending on the applicable state requirements, certain owners and operators may achieve equivalent or more emission reduction from their affected source(s) than the required reduction under the NSPS by complying with their state requirements. States may adopt and enforce standards or limitations that are more stringent than the NSPS. See CAA section 116 and the EPA's regulations at 40 CFR 60.10(a). For states that are being proactive in addressing emissions from the oil and natural gas industry, it is important that the NSPS complement such effort. Therefore, in the final rule, through the process described in section VI.F.1.i for emerging technology, owners and operators may also submit an application requesting that the EPA approve certain state requirement as ''alternative means of emission limitations'' under the NSPS for their affected facilities. The application would include a demonstration that emission reduction achieved under the state requirement(s) is at least equivalent to the emission reduction achieved under the NSPS standards for a given affected facility. Consistent with section 111(h)(3), any application will be publicly noticed, which the EPA intends to provide within six months after receiving a complete application, including all required information for evaluation. The EPA will provide an opportunity for public hearing on the application and on intended action the EPA might take. The EPA intends to make a final determination within six months after the close of the public comment period. The EPA will also publish its determination in the **Federal Register**.

VII. Prevention of Significant Deterioration and Title V Permitting

A. Overview

This final rule will regulate GHGs under CAA section 111. In this section, the EPA is addressing how regulation of GHGs under CAA section 111 could have implications for other EPA rules and for permits written under the CAA Prevention of Significant Deterioration (PSD) preconstruction permit program and the CAA Title V operating permit program. The EPA is adopting provisions in the regulations that explicitly address some of these potential implications based on our review of the proposed regulatory text and comments received on the proposal.

For purposes of the PSD program, the EPA is finalizing provisions in part 60 of its regulations and explaining in this preamble that the current threshold for determining whether a PSD source must satisfy the best available control technology (BACT) requirement for GHGs continues to apply after promulgation of this rule. This rule does not require any additional revisions to state implementation plans (SIPs). With respect to the Title V operating permits program, we are finalizing provisions in part 60 and explaining in this preamble that this rule does not affect whether sources are subject to the requirement to obtain a Title V operating permit based solely on emitting or having the potential to emit GHGs above major source thresholds.

B. Applicability of Tailoring Rule Thresholds Under the PSD Program

EPA received several comments asking for clarification or changes to make clear that this rule did not directly regulate methane as a separate pollutant from GHG and that it would not cause sources to trigger PSD or Title V permitting requirements based solely on methane emissions.[96] This section discusses changes made in response to these comments as well as clarification as to what, if any, impact this rule has on PSD permitting. Section VII.C below addresses Title V-specific issues.

Under the PSD program in part C of title I of the CAA, in areas that are classified as attainment or unclassifiable for NAAQS pollutants, a new or modified source that emits any air pollutant subject to regulation at or above specified thresholds is required to obtain a preconstruction permit. This permit ensures that the source meets specific requirements, including application of BACT to each pollutant subject to regulation under the CAA. Many states (and local districts) are authorized by the EPA to administer the PSD program and to issue PSD permits. If a state is not authorized, then the EPA issues the PSD permits for facilities in that state.

To identify the pollutants subject to the PSD permitting program, EPA regulations contain a definition of the term ''regulated NSR pollutant.'' 40 CFR 52.21(b)(50); 40 CFR 51.166(b)(49). This definition contains four subparts, which cover pollutants regulated under various parts of the CAA. The second subpart covers pollutants regulated under section 111 of the CAA. The fourth subpart is a catch-all provision that applies to ''[a]ny pollutant that is otherwise subject to regulation under the Act.''

This definition and the associated PSD permitting requirements applied to GHGs for the first time on January 2, 2011, by virtue of the EPA's regulation of GHG emissions from motor vehicles, which first took effect on that same date. 75 FR 17004 (Apr. 2, 2010). GHGs became subject to regulation under the CAA and the fourth subpart of the ''regulated NSR pollutant'' definition became applicable to GHGs.

On June 3, 2010, the EPA issued a final rule, known as the Tailoring Rule, which phased in permitting requirements for GHG emissions from stationary sources under the CAA PSD and Title V permitting programs (75 FR 31514). Under its understanding of the CAA at the time, the EPA believed the Tailoring Rule was necessary to avoid a sudden and unmanageable increase in the number of sources that would be required to obtain PSD and Title V permits under the CAA because the sources emitted GHGs in amounts over applicable major source and major modification thresholds. In Step 1 of the Tailoring Rule, which began on January 2, 2011, the EPA limited application of PSD or Title V requirements to sources of GHG emissions only if the sources were subject to PSD or Title V ''anyway'' due to their emissions of non-GHG pollutants. These sources are referred to as ''anyway sources.'' In Step 2 of the Tailoring Rule, which began on July 1, 2011, the EPA applied the PSD and Title V permitting requirements under the CAA to sources that were classified as major and, thus, required to obtain a permit based solely on their potential GHG emissions and to modifications of otherwise major sources that required a PSD permit because they increased only GHG emissions above applicable levels in the EPA regulations.

In the PSD program, the EPA implemented the steps of the Tailoring Rule by adopting a definition of the term ''subject to regulation.'' The limitations in Step 1 of the Tailoring Rule are reflected in 40 CFR 52.21(b)(49)(iv) and 40 CFR 51.166(b)(48)(iv). With respect to ''anyway sources'' covered by PSD during Step 1, this provision established that GHGs would not be subject to PSD requirements unless the source emitted GHGs in the amount of 75,000 tons per year (tpy) of CO2 Eq. or more. The primary practical effect of this paragraph is that the PSD BACT requirement does not apply to GHG emissions from an ''anyway source'' unless the source emits GHGs at or above this threshold. The Tailoring Rule Step 2 limitations are reflected in 40 CFR 52.21(b)(49)(v) and 51.166(b)(48)(v). These provisions contain thresholds that, when applied through the definition of ''regulated NSR pollutant,'' function to limit the scope of the terms ''major stationary source'' and ''major modification'' that determine whether a source is required to obtain a PSD permit. See *e.g.,* 40 CFR 51.166(a)(7)(i) and (iii); 40 CFR 51.166(b)(1); 40 CFR 51.166(b)(2).

On June 23, 2014, the United States Supreme Court, in *Utility Air Regulatory Group* v. *Environmental Protection Agency,* issued a decision addressing the application of PSD permitting requirements to GHG emissions. The Supreme Court held that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source (or modification thereof) for the purpose of PSD applicability. The Court also said that the EPA could continue to require that PSD permits, otherwise required based on emissions of pollutants other than GHGs, contain limitations on GHG emissions based on the application of BACT. The Supreme Court decision effectively upheld PSD permitting requirements for GHG emissions under Step 1 of the Tailoring Rule for ''anyway sources'' and invalidated application of PSD permitting requirements to Step 2 sources based on GHG emissions. The Court also recognized that, although the EPA had not yet done so, it could ''establish an appropriate *de minimis* threshold below which BACT is not required for a source's greenhouse gas emissions.'' 134 S. Ct. at 2449.

In accordance with the Supreme Court decision, on April 10, 2015, the United States Court of Appeals for the District of Columbia Circuit (the D.C. Circuit) issued an amended judgment vacating the regulations that implemented Step 2 of the Tailoring Rule but not the regulations that implement Step 1 of the Tailoring Rule. The court specifically vacated 40 CFR 51.166(b)(48)(v) and 40 CFR 52.21(b)(49)(v) of the EPA's regulations, but did not vacate 40 CFR 51.166(b)(48)(iv) or 40 CFR 52.21(b)(48)(iv). The court also directed the EPA to consider whether any further revisions to its regulations are appropriate in light of *UARG* v. *EPA* and, if so, to undertake such revisions.

The practical effect of the Supreme Court's clarification of the reach of the CAA is that it eliminates the need for Step 2 of the Tailoring Rule and subsequent steps of the GHG permitting phase-in that the EPA had planned to consider under the Tailoring Rule. This also eliminates the possibility that the

[96] As is discussed elsewhere, the EPA has made clear that the pollutant subject to regulation is GHG, in the form of methane. Additional regulatory language in 40 CFR 60.5360a has been added to provide additional clarity.

promulgation of GHG standards under section 111 could result in additional sources becoming subject to PSD based solely on GHGs, notwithstanding the limitations the EPA adopted in the Tailoring Rule.[97] However, for an interim period, the EPA and the states will need to continue applying parts of the PSD definition of ''subject to regulation'' to ensure that sources obtain PSD permits meeting the requirements of the CAA.

The CAA continues to require that PSD permits issued to ''anyway sources'' satisfy the BACT requirement for GHGs. Based on the language that remains applicable under 40 CFR 51.166(b)(48)(iv) and 40 CFR 52.21(b)(49)(iv), the EPA and states may continue to limit the application of BACT to GHG emissions in those circumstances where a source emits GHGs in the amount of at least 75,000 tpy on a CO2 Eq. basis. The EPA's intention is for this to serve as an interim approach while the EPA moves forward to propose a GHG significant emission rate (SER) that would establish a *de minimis* threshold level for permitting GHG emissions under PSD. Under this forthcoming rule, the EPA intends to propose restructuring the GHG provisions in its PSD regulations so that the *de minimis* threshold for GHGs will not reside within the definition of ''subject to regulation.'' This restructuring will be designed to make the PSD regulatory provisions on GHGs universally applicable, without regard to the particular subparts of the definition of ''regulated NSR pollutant'' that may cover GHGs. Upon promulgation of this PSD rule, it will then provide a framework that states may use when updating their SIPs consistent with the Supreme Court decision.

While the PSD rulemaking described above is pending, the EPA and approved state, local, and tribal permitting authorities will still need to implement the BACT requirement for GHGs. In order to enable permitting authorities to continue applying the 75,000 tpy CO2 Eq. threshold to determine whether BACT applies to GHG emissions from an ''anyway source'' after GHGs are subject to regulation under CAA section 111, the EPA has concluded that it is appropriate to adopt language in 40 CFR 60.5360a, language that is substantially similar to language found in 40 CFR 60.5515 (subpart TTTT).

While most of the Tailoring Rule limitations are no longer needed to avoid triggering the requirement to obtain a PSD permit based on GHGs alone, the limitation in 40 CFR 51.166(b)(48)(iv) and 40 CFR 52.21(b)(49)(iv) will remain important to provide an interim applicability level for the GHG BACT requirement in ''anyway source'' PSD permits. Thus, there continues to be a need to ensure that the regulation of GHGs under CAA section 111 does not make this BACT applicability level for ''anyway sources'' effectively inoperable. The language in 40 CFR 60.5360a is necessary to avoid this result in light of the judicial actions described above.

C. Implications for Title V Program

Under the Title V program, certain stationary sources, including ''major sources'' are required to obtain an operating permit. This permit includes all of the CAA requirements applicable to the source, including adequate monitoring, recordkeeping, and reporting requirements to ensure sources' compliance. These permits are generally issued through EPA-approved state Title V programs.

In the proposal for this rulemaking, the EPA indicated that ''the air pollutant that it propose[d] to regulate [was] the pollutant GHGs (which consist of the six well-mixed gases), consistent with other actions the EPA has taken under the CAA, although only methane will be reduced directly by the proposed standards.'' 80 FR 56600–56601 (Sept. 18, 2015).

Similar to the comments received on PSD permitting, the EPA received several comments asking for clarification to make clear that this rule did not directly regulate methane as a separate pollutant from GHG and that it would not cause sources to be considered a major source under the Title V permitting program based solely on having methane emissions above the major source threshold. Several of these comments suggested that this issue could be addressed by adding provisions similar to those that appear in 40 CFR 60.5515 (subpart TTTT).

The immediately preceding section provides some general background about the application of the PSD and Title V permitting programs to GHG emissions. With respect to Title V, the definition of major source includes, in relevant part, a stationary source that ''directly emits or has the potential to emit, 100 tpy or more of any air pollutant subject to regulation.'' 40 CFR 70.2, 71.2 (definition of ''major source''). In the Tailoring Rule, a GHG threshold was incorporated into the definition of ''subject to regulation'' under 40 CFR 70.2 and 71.2, such that those definitions specify that GHGs are not subject to regulation, unless, as of July 1, 2011, the emissions of GHGs are from a source emitting or having the potential to emit 100,000 tpy of GHGs on a CO2 Eq. basis. 40 CFR 70.2, 71.2 (definition of ''subject to regulation''); see also 75 FR 31583, June 3, 2010. However, there is not a similar threshold for methane as a separately regulated air pollutant. Some comments reflected a concern that if methane were to be subject to regulation as a separate air pollutant, sources that emitted or had the potential to emit 100 tpy or more of methane would trigger major source status under Title V and any related requirements under the Title V permitting program.

In consideration of these comments and for purposes of clarity, the EPA has concluded that it is appropriate to adopt language in 40 CFR 60.5360a that is substantially similar to language found in 40 CFR 60.5515 (subpart TTTT). Consistent with the statement quoted above from the proposal, that provision along with the explanation in this preamble clarifies that the GHG standard established in this rulemaking regulates the air pollutant GHGs, although the standard is expressed in the form of a limitation on emission of methane. Accordingly, the air pollutant that is subject to regulation under this standard for Title V purposes is GHGs.

As noted above, on June 23, 2014, the United States Supreme Court issued its opinion in UARG v. EPA, 134 S.Ct. 2427 (June 23, 2014) and, in accordance with that decision, the D.C. Circuit subsequently issued an amended judgment in *Coalition for Responsible Regulation, Inc.* v. *Environmental Protection Agency,* Nos. 09–1322, 10–073, 10–1092 and 10–1167 (D.C. Cir., April 10, 2015). With respect to Title V, the Supreme Court said in *UARG* v. *EPA* that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a Title V operating permit. In accordance with that decision, the D.C. Circuit's amended judgment in *Coalition for Responsible Regulation, Inc.* v. *Environmental Protection Agency,* vacated the Title V regulations under review in that case to the extent that they require a stationary source to obtain a Title V permit solely because the source emits or has the potential to emit GHGs above the applicable major source thresholds. The D.C. Circuit also directed the EPA to consider whether any further revisions to its regulations

[97] As discussed in other portions of this rulemaking, GHG are the pollutant subject to regulation by this rule. The standards are specific to GHGs expressed in the form of limitations on emissions of methane. Changes, consistent with 40 CFR part 60, subpart TTTT as suggested by several of the commenters, have been made in 40 CFR 60.5360a to make this clear.

are appropriate in light of *UARG* v. *EPA,* and, if so, to undertake to make such revisions. These court decisions make clear that promulgation of CAA section 111 requirements for GHGs will not result in the EPA imposing a requirement that stationary sources obtain a Title V permit solely because such sources emit or have the potential to emit GHGs above the applicable major source thresholds.[98]

To be clear, however, unless exempted by the Administrator through regulation under CAA section 502(a), any source, including an area source (a ''non-major source''), subject to an NSPS is required to apply for, and operate pursuant to, a Title V permit that ensures compliance with all applicable CAA requirements for the source, including any GHG-related applicable requirements. This aspect of the Title V program is not affected by *UARG* v. *EPA,* as the EPA does not read that decision to affect either the grounds other than those described above on which a Title V permit may be required or the applicable requirements that must be addressed in Title V permits.[99] For the source category in this rule, there is an exemption in 40 CFR 60.5370a from the obligation to obtain a Title V permit for sources that are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). However, sources that are subject to the CAA section 111 standards promulgated in this rule and that are otherwise required to obtain a Title V permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) will be required to apply for, and operate pursuant to, a Title V permit that ensures compliance with all applicable CAA requirements, including any GHG-related applicable requirements.

VIII. Summary of Significant Comments and Responses

This section summarizes the significant comments on our proposed amendments and our response to those comments.

A. Major Comments Concerning Listing of the Oil and Natural Gas Source Category

As previously explained, the EPA interprets the 1979 listing of this source category to cover the oil and natural gas industry broadly. To the extent there is any uncertainty, EPA proposed, as an alternative in the 2015 proposal, to revise the listing of this source category to include oil production and natural gas production, processing, and transmission and storage. We received several comments regarding the EPA's interpretation of the 1979 category listing and its alternative proposal to revise that listing. Provided below is one such comment and the EPA's response. Other comments on this subject and the EPA's responses thereto can be found in the RTC.

Comment: One commenter argues that, in the proposed rule, the EPA seeks to unlawfully expand the scope of the oil and natural gas sector source category, even beyond the expansion that the EPA undertook in 2012 with subpart OOOO, which the commenter had also opposed as unlawful. The commenter asserts that the EPA's attempt here to expand even further the types of emissions sources that would be subject to the NSPS is likewise unlawful. The commenter notes that, in this proposal, several types of never before regulated emissions sources would be regulated under NSPS, specifically, hydraulically fractured oil well completions, pneumatic pumps and fugitive emissions from well sites and compressor stations, and that some source types would also be regulated more generally for methane and VOC emissions, as only a small subset are currently regulated for VOC: Pneumatic controllers, centrifugal compressors and reciprocating compressors (except for compressors at well sites).

The commenter notes that the EPA's proposed NSPS would cover an even greater number of very small source types in the EPA's broadly defined ''oil and natural gas source category,'' which, according to the EPA, includes production, processing, transmission and storage. The commenter notes that the EPA again maintains, as it did in the original subpart OOOO rulemaking, that all emissions sources proposed for regulation are covered by its 1979 listing of the oil and natural gas category.

The commenter claims that the EPA is incorrect that the 1979 original source category determination can be read to include the numerous smaller emissions points covered by this proposal. According to the commenter, the 1979 listing was focused on major emitting operations and cannot be reasonably construed as encompassing small, discrete sources that exist separate and apart from a large facility, like a processing plant.

The commenter claims that the EPA made clear in the 1979 listing notice that the category was listed to satisfy section 111(f) of the Clean Air Act. According to the commenter, that section required the EPA to create a list of ''categories of major stationary sources'' that had not been listed as of August 7, 1977, under section 111(b)(1)(A) of the Act, and to promulgate NSPS for the listed categories according to a set schedule. The commenter asserts that the EPA explained in the listing rule that its list included ''major source categories,'' which the EPA defined to include ''those categories for which an average size plant has the potential to emit 100 tons or more per year of any one pollutant.''

Although the commenter notes that the EPA provided no further explanation in its original 1979 listing decision as to what facilities it intended to regulate under the ''crude oil and natural gas production'' source category, the commenter claims that ''there can be no doubt that the category originally included 'stationary sources' (*i.e.,* 'plants') that typically have a potential to emit at least 100 tons per year of a regulated pollutant.''[100] The commenter argues that this communicates two important limitations on the original listing decision: First, the EPA was focused on discrete ''plants'' or ''stationary sources''; and second, the EPA was focused on large emitting plants or stationary sources. The commenter argues that, as a result, the original listing decision cannot reasonably be interpreted to extend to the types of sources the EPA seeks to regulate in the proposal and that the additional source types that the EPA seeks to regulate in this proposal could not plausibly be considered part and parcel of major emitting plants.

The commenter notes that the EPA interpreted the 1979 listing to be broader than the ''production source segment'' because the EPA evaluated equipment that is used in various segments of the natural gas industry, such as stationary pipeline compressor engines. 80 FR 56600, September 18, 2015. The commenter argues that this

[98] The EPA intends to propose revisions to the Title V regulations in a future rulemaking action to respond to the Supreme Court decision and the D.C. Circuit's amended judgment. To the extent there are any issues related to the potential interaction between the promulgation of CAA section 111 requirements for GHGs and Title V applicability based on emissions above major source thresholds, the EPA anticipates there would be an opportunity to consider those during that rulemaking.

[99] See Memorandum from Janet G. McCabe, Acting Assistant Administrator, Office of Air and Radiation, and Cynthia Giles, Assistant Administrator, Office of Enforcement and Compliance Assurance, to Regional Administrators, Regions 1–10, *Next Steps and Preliminary Views on the Application of Clean Air Act Permitting Programs to Greenhouse Gases Following the Supreme Court's Decision in Utility Regulatory Group* v. *Environmental Protection Agency* (July 24, 2014) at 5.

[100] *API Comments on the Proposed Rulemaking—Standards of Performance for New Stationary Sources: Oil and Natural Gas Production and Natural Gas Transmission and Distribution,* at 2 (December 4, 2015).

does not evince an intent to regulate non-major source types, but only that the Agency evaluated equipment located at what it perceived to be major facilities.

The commenter further notes that, in the preamble to the proposed NSPS for natural gas processing plants, the EPA described the major emission points of this source category to include process, storage and equipment leaks. However, the commenter argues that this does not support what the commenter claims as ''broad regulation of even the smallest sources in the oil and natural gas industry.'' [101] The commenter notes that the emissions points regulated in that rulemaking—process units and compressors—were located at gas processing plants. The commenter argues that it is telling that the Agency decided to regulate only natural gas processing plants—the closest thing to a major emitting plant that can be found in this sector—in that NSPS.

Response: In 1979, the EPA published a list of source categories, including ''oil and natural gas production,'' pursuant to a new section 111(f) in the Clean Air Act amendment of 1977, which directed the EPA to list under 111(b)(1)(A) ''categories of major stationary sources'' and establish standards of performance for the listed source categories. As explained in the September 2015 proposal preamble and earlier in section IV.A of this preamble, the EPA interprets the 1979 listing to broadly cover the oil and natural gas industry. The commenter claims that the EPA's interpretation is incorrect because the 1979 listing included only large emitting plants or stationary sources. However, the commenter's interpretation fails for the following reasons.

The commenter's claim relies in large part on the EPA's definition of a ''major source category'' in the 1979 listing action, which was defined as ''an average size plant that has the potential to emit 100 tons or more per year of any one pollutant,'' 44 FR 49222 (August 21, 1979). However, despite the definition above, the EPA provided notice in the listing action that ''certain new sources of smaller than average size within these categories may have less than a 100 ton per year emission potential.'' 43 FR 38872, 38873 (August 31, 1978). The EPA thus made clear that the 1979 listing did not include only those meeting the major source threshold. The EPA's contemporaneous explanation indicates that, while the 1979 action focused on large emitting sources, the EPA recognized at the time that there are smaller sources that may warrant regulation.

The commenter next argues that the 1979 listing included only large plants because it included only ''stationary sources.'' However, ''stationary sources,'' as defined in section 111(a)(2), include not only buildings, structures and facilities (e.g., plants) but also installations, such as equipment, that emit or may emit any pollutant. Moreover, this definition contains no size limitation.

The commenter cites to the EPA's initial NSPS promulgation in 1985, which regulated only natural gas processing plants, as evidence that the 1979 listing included only large emitting stationary sources and, in the case of the oil and natural gas source category, only natural gas processing plants. However, the fact that the EPA regulated only natural gas processing plants in the 1985 NSPS does not establish that the listed oil and natural gas source category consists of only large natural gas processing plants. On the contrary, this argument ignores that the category, as listed, also includes crude oil production. Further, such narrow view is inconsistent with the EPA's clarification of the 1979 listing and the statutory definition of ''stationary sources,'' neither of which limits a listed category of stationary sources under section 111 only to large plants such as natural gas processing plants, as explained above.

The commenter's assertion is also refuted by the EPA's statements during the development of the 1985 NSPS. Specifically, in the preamble to the proposed rule for equipment leaks at natural gas processing plants, the EPA described the major emission points of this source category to include process, storage and equipment leaks, which can be found in various segments of the oil and natural gas industry. Further, as mentioned earlier, the EPA described the listed oil and natural gas source category to include emission points that the EPA did not regulate at that time, such as ''well systems field oil and gas separators, wash tanks, settling tanks and other sources.'' 49 FR at 2637. The EPA explained in that action that it could not address these emission at that time because ''best demonstrated control technology has not been identified.''

In light of the above, EPA reasonably interprets the 1979 listing to include the sources regulated under the 2012 oil and gas NSPS as well as those subject to today's action. The EPA established well completion performances standards for hydraulically fractured gas wells in the 2012 NSPS and for oil wells in today's action. These standards address some of the above mentioned well system emissions that the EPA could not regulate previously due to the lack of data. In addition, as mentioned above, the EPA had previously identified equipment leaks as a major emission point from this listed source category and established leaks standards for natural gas processing plants. Today's action further reduces emissions from equipment leaks by establishing work practice standards to detect and repair fugitive emissions at well sites and compressor stations. Emissions from equipment do not result only from leaks but also from normal operations that, if uncontrolled, are vented into the atmosphere. Therefore, both the 2012 NSPS and today's rule include performance standards for certain equipment used throughout the oil and natural gas industry, such as storage vessels, pneumatic controllers, pneumatic pumps, and compressors. Because these equipment are widely used across this industry, they contribute significant amount of emissions even if emissions from an individual piece of equipment may not be big.[102]

The commenter's main concern appears to be with the EPA regulating what the commenter claims to be ''very small emission sources'' and, therefore, unreasonable. However, section 111(b)(1)(A) requires that the EPA list source categories, not emission sources. In listing a source category, the EPA is not required to identify specific emission points within that source category. However, having listed a source category, the EPA is then required under section 111(b)(1)(B) to establish through rulemaking performance standards that reflect the best system of emission reductions, which would entail evaluation of emissions, control options, and other considerations (including their costs) for the sources to be regulated. Therefore, specific concerns with regulation of certain emission sources can be addressed during the rulemaking to establish such performance standards, where a commenter can argue that controlling a specific type of source is unreasonable under 111(b)(1)(B).

For the reasons stated above, the commenter fails to support its claim that the EPA's interpretation of the 1979 listing is unlawful. The commenter also fails to support its interpretation of the 1979 listing. The EPA's interpretation of

[101] *Id.*

[102] For example, based on industry wide estimate, high-bleed pneumatic controllers (from production through transmission and storage) emit in total of 87,285 tons of VOC and 350,000 tons of methane (8.7 million metric tons of CO_2e).

the 1979 listing therefore remains unchanged.

Comment: The commenter claims that the EPA fails to make the required statutory findings under section 111(b)(1)(A) to support its proposed revision to the 1979 listing. The commenter asserts that, under section 111(b)(1)(A), the EPA is authorized to regulate additional source types if and only if it: (1) Defines a discrete ''category'' of stationary sources; and (2) determines that emissions from the source category cause or significantly contribute to endangerment to health or the environment.

The commenter claims that the EPA makes no effort whatsoever to demonstrate that emissions from the particular additionally-regulated sources in subpart OOOOa cause or contribute to endangerment to health or the environment. Instead, the Agency simply asserts general public health effects associated with GHGs, VOC, and SO_2 and then evaluates emissions from oil and natural gas sources generally. See 80 FR 56601–08, September 18, 2015. For methane, the EPA merely breaks down emissions into four general ''segments'' (natural gas production, natural gas processing, natural gas transmission and storage, and petroleum production), but does not evaluate particular source type emissions within those segments. The EPA does nothing to break down its evaluation of emissions even by sector segment for SO_2 and VOC. This failure to investigate the key statutory listing criteria is patently arbitrary and plainly violates the requirement in section 307(d)(3) of the Clean Air Act to clearly set forth the basis and purpose of the proposal.

The commenter claims that under the EPA's logic, as long as certain types of stationary sources in a category, or segment of a category, cause or significantly contribute to endangerment to health or the environment, the Agency can lump together in the defined source category (or segment of a source category) all manner of ancillary equipment and operations, even if those ancillary equipment and operations do not in and of themselves significantly contribute to the previously identified endangerment. See 80 FR 56601, September 18, 2015. This is not a reasonable interpretation of section 111(b)(1)(A) because such an interpretation would bestow virtually unlimited regulatory authority upon the EPA, allowing the EPA to evade the express listing criteria by creating loose associations of nominally related sources in a sector.

Response: The commenter claims that the EPA must separately list and make the required findings under CAA section 111(b)(1)(A) for the ''additional source types'' from the oil and natural gas industry that were not covered by the 1979 listing. First of all, the EPA disagrees that there are such ''additional source types'' because, for the reasons stated in section IV.A of this preamble and the response to comment immediately above, the EPA interprets the 1979 listing to broadly cover the oil and natural gas industry. To the extent there is any uncertainty, the EPA rejects the commenter's claim that the 1979 listing covers only natural gas processing plants. But, more importantly, the EPA rejects this comment because it is contrary to the law.

CAA section 111(b)(1)(A) requires that the EPA list a category of sources ''if in [the Administrator's] judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health and welfare.'' [103] The provision is clear that the listing and endangerment findings requirements are to be made for source categories, not specific emission sources within the source category. The provision also does not require that the EPA identify all emission points within a source category when listing that category.

The commenter's claim that the EPA must separately list and make findings for particular emission source types within individual segments of the natural gas industry clearly contradicts with the plain language of section 111(b)(1)(A) which, as discussed above, is stated in terms of source category, not emission source types. Regardless, the EPA has satisfied the two criteria the commenter has identified as required by section 111(b)(1)(A): (1) Define a discrete category of stationary sources; and (2) determine that emissions from the source category cause or significantly contribute to endangerment to health or the environment. Although the EPA does not believe that revision to the 1979 category listing to be necessary for today's action, the EPA is finalizing as an alternative its proposed revision of the category listing to broadly include the oil and natural gas industry. In support of the revision, the final rule includes the Administrator's determination under section 111(b)(1)(A) that, in her judgment, this source category, as defined in this revision, contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.

[103] As previously mentioned, the required findings under section 111(b)(1)(A) is commonly referred to as the ''endangerment findings.''

The commenter also appears to claim that the EPA cannot revise the scope of a listed source category, but must instead separately list and make findings for what the commenter considers as ''additional source types'' within an already listed source category. The commenter offers no legal basis to support its claim because there is none. On the contrary, as explained below, the commenter claim impermissibly restricts the EPA's authority under section 111(b)(1)(A).

Section 111(b)(1)(A) requires that the EPA revise the category listing from time to time; it does not limit such revision to simply adding new source categories. The only criteria that section 111(b)(1)(A) states for the EPA to apply to category listing revision are the same as those for the initial category listing: That the category ''causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health and welfare.'' Thus, the statute leaves the EPA with the discretion to determine how to carry out such task, and that gives the EPA the flexibility to list and revise the list, including redefining the scope of a previously listed category, as long as long as the EPA meets the above criteria with the requisite endangerment findings for the source category as a whole. It allows the EPA to revise a category listing to include sources that, though not included in the initial listing (*e.g.,* the EPA might now have known about it at the time), reasonably belong in a listed source category. The commenter provides no compelling reason that such emission sources need a separate category listing and endangerment finding. In light of the above, the commenter's claim for a separate category listing and endangerment finding is not only unsupported by the statute, it unreasonably curtails the discretion section 111(b)(1)(A) provides the EPA in executing its category listing and revision authority under that provision. For the reasons stated above, the EPA disagrees with this comment.

B. Major Comments Concerning EPA's Authority To Establish GHG Standards in the Form of Limitations on Methane Emissions

As previously explained in section IV.D, the EPA's authority for regulating GHGs in this rule is CAA section 111. The standards in this rule that are specific to GHGs are expressed in the form of limitations on emissions of methane, and not the other constituent gases of the air pollutant GHGs. We received several comments regarding the EPA's interpretation of CAA section 111. Provided below is a summary of such comments and the EPA's response. Other comments on this subject and the EPA's responses thereto can be found in the RTC document.

Comment: Several commenters argued that the EPA cannot rely on the 2009 Endangerment Finding for GHG to justify the limitations of methane in this rule. The commenters made several arguments.

First, some commenters asserted that the EPA cannot regulate methane alone or specifically without a new Endangerment and Cause or Contribute Finding for the individual gas, because the original 2009 Finding defined the pollutant as the six well-mixed greenhouse gases. One commenter further stated that it is unlawful for the EPA to regulate only methane based on an endangerment finding that is largely attributable to other pollutants and that, of the six greenhouse gases, carbon dioxide is emitted in vastly greater quantities (even on a carbon dioxide equivalent basis) than methane.

Second, some commenters argue that a new endangerment finding is necessary for each pollutant regulated in a given source category. One commenter claims that section 111(b)(1)(A) of the CAA requires the EPA to list a category of stationary sources if, in the Administrator's judgment, the category causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. The commenter further argues that this CAA section unambiguously requires the EPA to list and regulate according to endangerment and significant contribution findings for particular pollutants. The commenter goes to state that it is unreasonable for the EPA to use a cause-or-contribute finding made for one pollutant thirty years ago in order to justify controlling a different pollutant today. The commenter asserts that a ''rational basis test'' is insufficient justification, and that the term ''rational basis'' is not found in section 111.

Third, some commenters argue that methane does not endanger human health or welfare. One commenter states that methane is naturally occurring and is non-toxic, that it does not accumulate in the body, that the only real risks that it poses are that it is flammable when present in high concentrations, and that inhaling high levels can cause oxygen deprivation. Another commenter claims that recent science supports a weakening of the case for human-caused global warming.

Finally, some commenters state that the impacts of the rule will be very small. One commenter argues that ''the oil and gas sector do [sic] not *significantly* cause or contribute to climate change'' because methane emissions from that sector ''account for only 3 percent of total United States domestic GHG emissions, just over 2 percent of the total United States GHG Inventory, and 0.3 percent of Global GHG emissions'' and transmission and storage is only a third of that total.

Response: As a general matter, commenters on this issue consistently mischaracterize the EPA's actions. The standards in this rule that are specific to GHGs are expressed in the form of limitations on emissions of methane. For these standards, GHG is the regulated pollutant. An endangerment finding is only required when the EPA lists a source category under section 111(b)(1)(A). Nothing in section 111 requires that the EPA make further endangerment findings with respect to each pollutant that it regulates under section 111(b)(1)(B). By considering whether there is a rational basis to regulate a given pollutant from a listed source category, the EPA ensures that it regulates pollutants that warrant regulation.

For purposes of this final rule, the EPA's rational basis is supported, in part, by the analysis that supported the 2009 Endangerment Finding. If, as commenters argue, the EPA is required to make additional findings of endangerment and cause-or-contribute for this final rule, then the analysis that supported the 2009 Endangerment Finding, along with other facts presented herein, including the information in sections IV.B and C, would be sufficient to make these findings.

While the 2009 Endangerment Finding defined the pollutant as the ''aggregate group of the well-mixed greenhouse gases'' the finding was also clear that a given source category does not have to emit every single one of these gases in order to contribute to the pollution in question. *See* 74 FR 66496–99 and 66541 (December 15, 2009). Specifically, as we explained in the 2009 Endangerment Finding, two of the six pollutants (PFCs and SF_6) are not emitted by motor vehicles, the source category in question in the 2009 Endangerment Finding. Moreover, while motor vehicles contribute to emissions of HFC–134a, there are many other HFCs which are not emitted by that source. Just as the GHG emissions from motor vehicles do not need to contain all six gases in order to be regulated, the GHG emissions from the oil and gas sector do not need to contain all six gases. Therefore, the EPA does not need to make an endangerment finding for methane alone: The 2009 Endangerment Finding that defines the aggregate group of six well-mixed gases as the air pollution addresses emissions of any individual component of that aggregate group and, therefore, supports the rational basis for this final rule.

Next, the assertion that methane has no risks beyond flammability is false. While methane is indeed produced from natural sources, the health and welfare risks of elevated concentrations of greenhouse gases (including methane) was detailed in the 2009 Endangerment Finding. Moreover, methane is a precursor to tropospheric ozone formation, which also impacts human health. As further context, according to the IPCC, historical methane emissions contribute the second most warming today of all the greenhouse gases, after carbon dioxide. This makes methane emission reductions an important contribution to reducing the atmospheric concentrations of the six well-mixed greenhouse gases.

Lastly, the climate benefits anticipated from the implementation of this rule are consequential in terms of the quantity of methane reduced, particularly in light of the potency of methane as a GHG. The reductions are additionally important as the United States oil and natural gas sector emits about 32 percent of United States methane emissions and about 3.4 percent of all United States GHGs. The final standards are expected to reduce methane emissions annually by about 6.9 million metric tons CO_2 Eq. in 2020 and by about 11 million metric tons CO_2 Eq. in 2025. To gives a sense of the magnitude of these reductions, the methane reductions expected in 2020 are equivalent to about 2.8 percent of the methane emissions for this sector reported in the United States GHG Inventory for 2014. Expected reductions in 2025 are equivalent to around 4.7 percent of 2014 emissions. As discussed in section IX.E, the estimated monetized benefits of methane emission reductions resulting from this rule are $160 million to approximately $950 million for reduced emissions in 2020, and $320 million to $1.8 billion for reduced emissions in 2025, depending on the discount rate used. The magnitude of these benefits estimates demonstrates that the methane reductions are consequential from an economic perspective, as well as physical perspective.

C. Major Comments Concerning Compressors

1. Wet Seal Centrifugal Compressors With Emission Rates Equal to or Lower Than Dry Seal Centrifugal Compressors

Comment: The EPA received several comments asserting that there are many wet seal centrifugal compressors that have emissions that are equal to, or lower than, dry seal compressors. One commenter notes that the EPA cites 6 standard cubic feet per minute (scfm) as the emission rate for dry seals and that a wide variety of wet seal systems are in use with varying rates of de-gas emissions and that if wet seal system can meet an emissions performance specification on par with dry seals (*i.e.,* 6 scfm), they should be exempt from the 95 percent reduction requirement. One commenter states that data indicate that a well-maintained wet seal will have a methane emission rate comparable to or lesser than dry seals and that the emission rate for commenter's compressors is significantly lower than the average rate identified in the EPA's National Emissions Inventory for this kind of source.

Response: The emissions factor used in our BSER analysis is an average factor calculated from available emissions information. As such, there are some wet seal centrifugal compressors that have a lower emission rate than the average emission rate. However, we have not been provided, nor do we have, any data indicating that there is a specific type or significant population of wet seal centrifugal compressors that have emission rates that are equal to or lower than dry seal compressors. We acknowledge that a well-maintained wet seal compressor may have lower emissions; however, as noted, the rule is based on an average emission factor derived from the best available information on a population of wet seal compressors. We have no data on which to base an exemption or different requirement for a subcategory of merely presumed low-emitting wet seal centrifugal compressors.

2. Regulation of Centrifugal and Reciprocating Compressors at Well Sites

Comment: The EPA received several comments opposing the exemption of centrifugal and reciprocating compressors located at well heads from the requirements of the rule. The commenters state that there are thousands of well head reciprocating compressors across the nation as well as some centrifugal compressors at well heads, and they pose a significant source of emissions unless properly controlled. The commenters contend that the reason the EPA claims to exclude these compressors is based on EPA data that show no centrifugal compressors located at well heads and on the determination that it is not cost effective to regulate these reciprocating compressors. Commenters state that the GHGRP data shows that there are centrifugal compressors located at well heads and that they should be regulated under the rule. Further, commenters assert that the EPA's cost effectiveness determination for reciprocating compressors is arbitrary because it was based on outdated emission factors and that if updated, the revised emissions would render the control for the well head compressors as cost-effective. Commenters suggest that the EPA should have relied on updated emission factors to estimate emissions from well-site compressors as it did to estimate emissions from gathering sector compressors, or at least explained why it failed to rely on updated emissions data to estimate emissions from well-site compressors.

Response: The emissions estimates presented in the proposal were based on the most robust data available at the time of their development. The EPA began collecting data through GHGRP on centrifugal compressors in the onshore petroleum and natural gas production segment in 2011. However, reporting of input data for compressors, including the count of centrifugal compressors at a facility, in onshore production was deferred until 2015 and published for the first time in October 2015. As a result, data on the number of centrifugal compressors were not available through GHGRP at the time of the development of the NSPS OOOOa proposal.

The EPA agrees with the commenter that the newly available data from GHGRP show the presence of centrifugal compressors in the onshore production segment, but the EPA disagrees with the commenter that it should cover these sources under the final rule. Although GHGRP data shows that 15 reporters indicated 69 centrifugal compressors at production facilities, the data do not provide a method to determine the number of centrifugal compressors with wet seals in onshore production. The GHGRP does not collect data on seal type (wet seal and dry seal) for onshore production. The EPA is not aware of other data sets on wet seals in the onshore production segment. Based on available data on the number of centrifugal compressors in onshore production, it is unlikely that there is a large population of centrifugal compressors with wet seals in onshore production.

With respect to emission factors for reciprocating compressors at well sites, the EPA proposed to exempt these compressors from the standards because we found that the cost of control for reciprocating compressors at well sites is not reasonable. Commenters on the 2014 Oil and Gas White Papers and on the subpart OOOOa proposal did not provide new data available for development of emission factors for reciprocating compressors at well sites. The EPA has not identified additional data sources for development of emission factors for reciprocating compressors at well sites and, therefore, has not updated its emissions estimate for this source. We continue to believe the cost of control for reciprocating compressors at well sites remains unreasonable. The final rule exempts centrifugal and reciprocating compressors at well sites.

3. Condition-Based Maintenance

Comment: The EPA solicited comment on an alternative to the proposed requirements which consists of monitoring of rod packing leakage to identify when the rate of rod packing leakage indicates that packing replacement is needed. Under such a condition-based maintenance provision, rod packing would be inspected or monitored based on a prescribed method and frequency and rod packing replacement, or repair would be required once a prescribed leak rate was observed. We requested additional information on the technical details of this condition-based concept.

Several commenters state that the rule should include an alternative maintenance program and allow operators flexibility to use a condition-based maintenance approach to reduce emissions rather than a prescribed maintenance schedule as currently included in the rule. In addition to controlling emissions, commenters assert that a condition-based maintenance may extend the operation of functional rod packing, eliminate premature and wasteful rod packing maintenance/replacement and, possibly, where rod packing leakage increases quicker than is typical, condition-based maintenance can result in earlier maintenance than EPA's proposed prescribed maintenance schedule. Commenters note that condition-based maintenance has been a proven successful technique for reducing methane emissions through the Natural Gas STAR program, where rod packing leaks were periodically monitored and the value of the incremental leaked gas (relative to leak rates for "new" packing) was compared to the rod packing maintenance cost. When the incremental lost gas value exceeded the maintenance/replacement cost, the rod packing maintenance was determined to be cost-effective.

Other commenters noted that because operators in transmission and storage segment do not own the gas, a different performance metric could be used and recommended a metric based on a defined leak rate or change in leak rate over time. Commenters recommended possibly setting a threshold at a leak rate above 2 scfm, combined with annual monitoring, which would require rod packing maintenance/replacement within nine months or during the next unit shutdown, whichever is sooner and which is consistent with a draft California Air Resources Board (CARB) regulation for oil and gas operations.

Response: The EPA disagrees with the commenters that the rule should include an alternative maintenance program and allow operators flexibility to use condition-based maintenance approach to reduce emissions rather than a prescribed maintenance schedule. While we received comment supporting the addition of a threshold-based or condition-based maintenance provision, we did not receive sufficient technical details to properly evaluate this alternative for inclusion in the rule. Although condition-based maintenance has been shown to be effective under the Natural Gas STAR program, the criteria on which rule requirements could be based would require significantly more data and analysis. Specifically, in order to evaluate such a provision for the rule, we would need to determine an appropriate leak-rate threshold which would trigger rod packing replacement. Commenters suggested 2 scfm demonstrated acceptable rod packing leakage; however, the commenters provided no substantive data as to the reason for this threshold. Commenters also recommended that we model the provision after the California Air Resources Board proposed regulation which was based on input from rod packing vendors. Although some valuable information was provided, the level of technical data and information necessary to analyze all aspects of such a provision were not provided. Therefore, we are unable to evaluate the condition-based maintenance provision for inclusion in the rule at this time.

D. Major Comments Concerning Pneumatic Controllers

1. Studies That Indicate Emission Rates for Low-Bleed Pneumatic Controllers That Are Higher Than the EPA Estimates

Comment: The EPA received comment that several recent studies report that pneumatic controllers emit more than they are designed to emit and that their emission rate is higher than the currently estimated EPA emission rate for pneumatic controllers. Specifically, the commenters noted that studies indicated that controllers were observed to have emissions inconsistent with the manufacturer's design and were likely operating incorrectly due to maintenance or equipment issues. Low-bleed pneumatic controllers were observed to have emission rates that were 270 percent higher than the EPA's emission factor for these devices, in some cases approaching the emission rate of high-bleed controllers.

Response: The emissions estimates presented in the proposal were based on the most robust data available at the time of their development. The EPA is familiar with the studies discussed in the comments summarized here and several of those studies were discussed in the EPA's Oil and Gas White Paper. The EPA has reviewed available data; because of the lack of emissions data that are straightforward to use in assessment of emissions from specific bleed rate categories (*i.e.,* high-bleed and low-bleed), the EPA has retained the emission factors for pneumatic controllers used in the proposal analysis and has retained the requirements for pneumatic controllers.

2. Capture and Control of Emissions From Pneumatic Controllers

Comment: The EPA received comment that pneumatic controllers should be required to capture emissions through a closed vent system and route the captured emissions to a process or a control device, similar to the approach the EPA has taken in its proposed standards for pneumatic pumps and compressors. The commenters cite recent Wyoming proposed rules for existing pneumatic controllers that allow operators of existing high-bleed controllers to route emissions to a process and the California Air Resources Board (CARB) proposed rules which requires that operators capture emissions and route to a process or control device. Commenters state that this approach would work for all types of pneumatic controllers and that this approach would be cost effective based on the costs identified for pneumatic pumps in the TSD.

Response: The EPA disagrees with the commenters that capturing and routing emissions from pneumatic controllers to a process or control device is a viable control option under our BSER analysis. While the commenter stated that a few permits in Wyoming indicate that a facility is capturing emissions from controllers and routing to a control device, we believe that there is insufficient information and data available for the EPA to establish the control option as the BSER. For more information, please see the RTC.

E. Major Comments Concerning Pneumatic Pumps

1. Compliance Date

Comment: Commenters stated that the EPA requires that new or modified pneumatic pumps at a site that currently lack an emission control device will become an affected facility if a control device is later installed; and, the facility must be in compliance within 30 days of installation of the new control device. One commenter states that 30 days does not provide such sources sufficient time to come into compliance. The commenter suggests that the rule be revised to require compliance within 30 days of startup of the control device so that the operator can ensure that the control device is properly tested after installation without concern over triggering non-compliance for pneumatic pump controls.

Response: We agree that additional time is appropriate for designing connections and testing after control device installation. Therefore, we have revised the compliance date in the final rule with respect to control devices that are installed on site after installation of the pneumatic pump affected facility. In the final rule, the compliance date for pneumatic pump affected facilities to be routed to a newly installed onsite control device 30 days after startup of the control device.

2. Subsequent Removal of Control Device

Comment: Several commenters expressed concern that the rule did not provide a way to remove control equipment from a site when it is no longer needed for the purpose for which it was installed. Further, they requested that the EPA clarify that a source ceases to be an affected facility if the control device is no longer needed for other equipment. The commenters cite an example where the exiting control device onsite is installed for a subpart OOOO storage vessel and subsequently the storage vessel's potential to emit falls below 6 tpy. If this were to occur, the storage vessel would no longer be subject to regulation and the control device would no longer be necessary.

Response: The EPA agrees that the intent of the proposal was not to require existing control devices that are no longer required for their original purposes to remain at a site only to control pneumatic pump affected facility emissions. Therefore, the final rule clarifies that subsequent to the removal of a control device and provided that there is no ability to route to a process, a pneumatic pump affected facility is no longer required to comply with § 60.5393a(b)(1) or (2). However, these units will continue to be affected facilities and we are requiring pneumatic pump affected facilities to continue following the relevant recordkeeping requirements of § 60.5420a even after an existing control device is removed.

3. Limited-Use Pneumatic Pumps

Comment: Commenters state that there are natural gas-driven pneumatic pumps which are used intermittently to transfer bulk liquids. These limited use pumps may be manually operated as needed or may be triggered by a level controller or other sensor. Specific examples provided by the commenters include engine skid sump pumps, pipeline sump pumps, tank bottom pumps, flare knockout drum pumps, and separator knockout drum pumps that are used to pump liquids from one place to another. The commenters contend that these pumps do not run continuously or even seasonally for long periods but only run periodically as needed. Thus, these pumps do not exhaust large volumes of gas in the aggregate. For this reason, the commenters requested that the final rule include an exemption for limited-use pneumatic pumps.

Response: In the TSDs to the proposed and final rule, the emission factors we used for pneumatic pumps assumed that the pumps operated 40 percent of the time. While we understood that pneumatic pumps typically do not run continuously, we did assume that the 40 percent usage was distributed evenly throughout the year. However, based upon the comments we received, the usage of some pneumatic pumps is much more limited than we previously determined and not spread evenly throughout the year. We did not intend to regulate these limited-use pneumatic pumps and are not including limited-use pneumatic pumps in the definition of pneumatic pump affected facilities that are located at well sites. Specifically, if a pump located at a well site operates for any period of time each day for less than a total of 90 days per year, this limited-use pneumatic pump is not an affected facility under this rule. We believe this requirement is sufficient to address the commenters' concerns for both intermittent use and temporary use pneumatic pumps.

Because we believe there are multiple viable alternatives available at natural gas processing plants that are not available at well sites, we do not believe it is necessary to exclude limited-use pneumatic pumps located at natural gas processing plants from the definition of pneumatic pump affected facility. Based on our best available information, both instrument air and electricity are readily available at natural gas processing plants. We believe owners and operators will choose instrument air over natural gas-driven pumps since their other pumps will be air powered. We also believe owners and operators can utilize electric pumps for intermittent activities cited by the commenters such as sump pumps and transfer pumps where it is safe to use an electric pump. Given these options, we conclude that it is not necessary to exclude limited-use pneumatic pumps located at natural gas processing plants from the definition of pneumatic pump affected facility in the final rule.

4. Removal of Tagging Requirements

Comment: Several commenters requested that the EPA remove the tagging requirement for pneumatic pump affected facilities. As written, the proposed rule required that operators tag pumps that are affected facilities and those that are not affected facilities. The commenters contend that the tagging requirement appears to add little value and is confusing. Commenters suggest operators should only be required to maintain a list of make, model, and serial number, rather than individual tags and that a list of make, model, and serial number will achieve the same results desired by the EPA, without presenting the unnecessary operational hurdles associated with individual tagging and recordkeeping.

Response: The EPA has reviewed the proposed tagging requirements and agrees with the commenters that the recordkeeping in lieu of tagging for pneumatic pumps affected facilities is sufficient. Therefore, the EPA has removed the tagging requirements for pneumatic pump affected facilities in the final rule.

5. Lean Glycol Circulation Pumps

Comment: The EPA solicited comments on the level of uncontrolled emissions from lean glycol circulation pumps and how they are vented through the dehydrator system. We received comments corroborating our understanding at proposal and in the white papers that emissions from these pumps are vented through the rich glycol separator vent or the reboiler still vent and are already regulated under 40 CFR part 63 subparts HH and HHH.

Response: The EPA's understanding during the proposal was that the lean glycol pumps are integral to the operation of the dehydrator, and as such, emissions from glycol dehydrator pumps are not separately quantified because these emissions are released from the same stack as the rest of the emissions from the dehydrator system, including HAP emission that are being controlled to meet the standards under the National Emission Standards for Hazardous Air Pollutants (NESHAP) at 40 CFR part 63 subparts HH and HHH. It is also our understanding from white paper commenters that replacing the natural gas in gas-assisted lean glycol pumps with instrument air is not feasible and would create significant safety concerns. Commenters on the white paper stated that the only option for these types of pumps are to replace them with electric motor driven pumps; however, solar and battery systems large enough to power these types of pumps are not currently feasible. Therefore, we have clarified that lean glycol circulation pumps are not affected facilities under the final pneumatic pumps standards.

F. Major Comments Concerning Well Completions

1. Request for a Limited Use of Combustion

Comment: Several commenters support the requirements for reducing completion emissions at oil wells; however, they express concern that the proposed rule does not go far enough in establishing a hierarchy of preference for the beneficial use options provided in the rule (i.e., routing the recovered gas from the separator into a gas flow line or collection system, re-injecting the recovered gas into the well or another well, use of the recovered gas as an onsite fuel source or use of the recovered gas for another useful purpose that a purchased fuel or raw material would serve) over what the commenters perceive to be the least-preferable option to route the emission to a combustion control device. Further, one commenter states that the technical infeasibility exemption in the rule is vague and could detract significantly from the overall value of this standard if not narrowly limited in application. The commenter notes that because of the swiftly increasing production of oil (along with associated natural gas) in the United States which produces very high initial rates of oil and associated gas, it is vital that the rule's requirements apply rigorously.

Response: The EPA agrees that REC should be preferred over combustion due to the secondary environmental impact from combustion. The final rule reflects such preference by requiring REC unless it is technically infeasible, in which event the recovered gas is to be routed to a completion combustion device. Further, to ensure that the exemption from REC due to technical infeasibility is limited to those situations where the operator can demonstrate that each of the options to capture and use gas beneficially is not feasible and why, we have expanded recordkeeping requirements in the final rule to include: (1) Detailed documentation of the reasons for the claim of technical infeasibility with respect to all four options provided in § 60.5375a(a)(1)(ii), including but not limited to, names and locations of the nearest gathering line; capture, re-injection, and reuse technologies considered; aspects of gas or equipment prohibiting use of recovered gas as a fuel onsite; and (2) technical considerations prohibiting any other beneficial use of recovered gas on site.

We believe these additional provisions will support a more diligent and transparent application of the intent of the technical infeasibility exemption from the REC requirement in the final rule. This information must be included in the annual report made available to the public 30 days after submission through CEDRI and WebFIRE, allowing for public review of best practices and periodic auditing to ensure flaring is limited and emissions are minimized.

G. Major Comments Concerning Fugitive Emissions From Well Sites and Compressor Stations

1. Modification Definitions for Well Sites

Comment: Several commenters assert that the definition of ''modification'' of a well site under the proposed rule in § 60.5365a(i) is overly broad because it would bring many existing well sites under the Rule's requirements. The commenters believe that drilling a new well or hydraulically fracturing an existing well does not increase the probability of a leak from an individual component and no new components result from these activities, thus the potential emissions rate does not change and should not be consider a modification.

Response: The EPA believes the addition of a new well or the hydraulically fracturing or refracturing of an existing well will increase emissions from the well site for the following reasons. These events are followed by production from these wells which generate additional emissions at the well sites. Some of these additional emissions will pass through leaking fugitive emission components at the well sites (in addition to the emissions already leaking from those components). Further, it is not uncommon that an increase in production would require additional equipment and, therefore, additional fugitive emission components at the well sites. We also believe that defining ''modification'' to include these two events, rather than requiring complex case-by-case analysis to determine whether there is emission increase in each event, will ease implementation burden for owners and operators. For the reasons stated above, EPA is finalizing the definition of ''modification'' of a well site, as proposed.

2. Monitoring Plan

Comment: Commenters expressed concerns about the elements of the proposed monitoring plans and encouraged the EPA to consult with the oil and gas industry and states to adopt requirements that would meet their specific needs. Commenters suggested that an area-wide monitoring plan should be allowed instead of a corporate-wide or site specific plan. The area plan would allow owners to write a plan that covers various areas for each specific region since operators may rely on contractors in one area due to location while company-owned monitoring equipment may be used within another area.

Response: The EPA participated in numerous meetings with industry, environmental and state stakeholders to discuss the proposed rule. During these meetings industry stakeholders further explained why a corporate-wide monitoring plan would be difficult to develop due to their corporate structures, well site locations, basin characteristics and many other factors. They also indicated that a site-specific plan would be redundant since many well sites within a district or field office are similar and would utilize the same personnel, contractors or monitoring equipment. The industry stakeholders provided input on specific elements of the monitoring plan, such as the walking path requirement. Based on the comments that we received and subsequent stakeholder meetings, we have made changes to the monitoring plan and have further explained our intent for the walking path. We have also modified the digital photograph recordkeeping requirements for sources of fugitive emissions. See section VI.f.1.h of this preamble for further discussion.

H. Major Comments Concerning Final Standards Reflecting Next Generation Compliance and Rule Effectiveness Strategies

1. Electronic Reporting

Comment: While some commenters express support, several commenters oppose electronic reporting of compliance-related records. Some of the commenters state that they have an obligation under the rule to maintain these records and make them available to the regulatory agency upon request, and this should be sufficient. Providing all the records requested under the proposed rule would likely cause a backlog of correspondence between the regulatory agency and the industry. Other commenters expressed concern that sensitive company information could be present in the records, and other parties could use a FOIA request to obtain the records.

Additional commenters pointed out that the EPA should not require electronic reporting until CEDRI is modified to accommodate the unique nature of the oil and natural gas production industry. As the commenters understand the operational characteristics of CEDRI, the system links reports for each affected facility to the site at which they are located. Under subparts OOOO and OOOOa, there is no unique site identifier. This would result in owners and operators having to deconstruct the annual report in order to obtain the affected facility level data needed for CEDRI. The EPA did not account for this burden and cost. The commenters request that should electronic reporting be required, that CEDRI be revised to accept the annual reports as currently specified in the proposed rule as a pdf file or hardcopy until these issues can be resolved. Commenters also request that CEDRI be modified to accept area-wide reports rather than site-level reports. Additionally, commenters noted that the definition of ''certifying official'' under CEDRI is different than in the proposed rule.

Finally, since the EPA did not propose regulatory language for these requirements, some commenters believe that the EPA cannot finalize these requirements without first proposing the regulatory language.

Response: The EPA notes that regulatory language for the electronic reporting requirements was available in § 60.5420a, § 60.5422a and § 60.5423a of the proposed rule.

The EPA thanks the commenters for the support for electronic reporting. Electronic reporting is in ever-increasing use and is universally considered to be faster, more efficient and more accurate for all parties once the initial systems have been established and start-up costs completed. Electronic reporting of environmental data is already common practice in many media offices at the EPA; programs such as the Toxics Release Inventory (TRI), the Greenhouse Gas Reporting Program, Acid Rain and NO_X Budget Trading Programs and the Toxic Substances Control Act (TSCA) New Chemicals Program all require electronic submissions to the EPA. The EPA has previously implemented similar electronic reporting requirements in over 50 different subparts within parts 60 and 63. WebFIRE, the public access site for these data, currently houses over 5000 reports that have been submitted to the EPA via CEDRI.

The EPA notes that reporting is an essential element in compliance assurance, and this is especially true in this sector. Because of the large number of sites and the remoteness of sites, it is unlikely that the delegated agencies will be able to visit all sites. By providing reports electronically in a standardized format, the system benefits air agencies by streamlining review of data, facilitating large scale data analysis, providing access to reports and providing cost savings through a reduction in storage costs. The narrative and upload fields within the CEDRI forms can even be used to provide information to satisfy extra reporting requirements that state and local air agencies may impose.

The EPA is sensitive to the complexity of the oil and gas regulations and the unique challenges presented by this sector. CEDRI forms are designed to be consistent with the requirements of the underlying subparts and are unique to each regulation. The forms are reviewed multiple times before being finalized, and they are subjected to a beta testing period that allows end-users to provide feedback on issues with the forms prior to requiring their use. Also, if a form has not yet been completed by the time the rule is effective, affected facilities will not be required to use CEDRI until the form has been available for at least 90 days. The EPA notes that we have recently developed a bulk upload feature for several subparts within CEDRI. The bulk upload feature allows users to enter data for sites across the country in a single file instead of having to submit individual reports for each site. This feature should alleviate some of the commenters' concerns.

The EPA is aware that facility personnel must learn the new reporting system, but the savings realized by simplified data entry outweighs the initial period of learning the system. Electronic reporting can eliminate paper-based, manual processes, thereby saving time and resources, simplifying data entry, eliminating redundancies, minimizing data reporting errors and providing data quickly and accurately. Reporting form standardization can also lead to cost savings by laying out the data elements specified by the regulations in a step-by-step process, thereby helping to ensure completeness of the data and allowing for accurate assessment of data quality. Additionally, the EPA's electronic reporting system will be able to access existing information in previously submitted reports and data stored in other EPA databases. These data can be incorporated into new reports, which will lead to reporting burden reduction through labor savings.

In 2011, in response to Executive Order 13563, the EPA developed a plan to periodically review its regulations to determine if they should be modified, streamlined, expanded, or repealed in an effort to make regulations more effective and less burdensome.[104] The plan includes replacing outdated paper reporting with electronic reporting. In keeping with this plan and the White House's Digital Government Strategy,[105] in 2013 the EPA issued an agency-wide policy specifying that EPA will start with the assumption that reporting will be electronic and not paper. The EPA believes that the electronic submittal of the reports addressed in this rulemaking increases the usefulness of the data contained in those reports, is in keeping with current trends in data availability, further assists in the protection of public health and the environment and will ultimately result in less burden on the regulated community. Therefore, the EPA is retaining the requirement to report these data electronically.

2. Third-Party Verification for Closed Vent Systems

Comment: Several commenters express opposition to a third-party verification system for the design of closed vent systems. Some of the commenters explain that they design their closed vent system using in-house staff. Many of the details regarding actual flow volumes and gas composition are unknown at the initial design stage, so it would not be possible to certify the design's effectiveness prior to construction. Also, storage vessels are designed to have some level of losses, so it would also not be possible to certify that the closed vent system routes all emissions to the control device.

Several of the commenters also express concern that the verification process discussed in the preamble to the proposed rule would create a complex bureaucratic scheme with no measurable benefits. Many of the commenters believe such a verification process would add a significant labor and cost burden that the EPA has not quantified. The EPA's contention that third-party verification ''may'' improve compliance is presented without any analysis or support and does not justify the costs of such a program.

Concerning the impartiality requirements outlined by the EPA, some of the commenters believe that it would be impossible to find someone who is qualified to do verification that could pass those requirements due to the interrelationship between the production and support companies over decades of working with one another. Some commenters contend that the EPA overestimates the availability of qualified third-party consultants, assuming that an impartial one could be found, that understands the industry well enough to competently review designs for closed vent systems.

Some of the commenters remind the EPA of the conclusions the Agency reached after proposing a similar third-party verification system for the Greenhouse Gas Reporting Program, in which the EPA expressed concerns about establishing third-party verification protocols, developing a system to accredit third-party verifiers, and developing a system to ensure impartiality.

Response: The EPA continues to believe that independent third party verification can furnish more, and sometimes better, data about regulatory compliance. With better data about compliance, regulatory agencies, including the EPA, would have more

[104] EPA's Final Plan for Periodic Retrospective Reviews, August 2011. Available at: *http://www.epa.gov/regdarrt/retrospective/documents/eparetroreviewplan-aug2011.pdf.*

[105] Digital Government: Building a 21st Century Platform to Better Serve the American People, May 2012. Available at: *https://www.whitehouse.gov/sites/default/files/omb/egov/digital-government/digital-government-strategy.pdf.*

information to determine what types of regulations are effective and how to spend their resources. A critical element to independent third party verification is to ensure third-party verifiers are truly independent from their clients and perform competently. We continue to believe that this model best limits the risk of bias or ''capture'' due to the third-party verifier identifying or aligning his interests too closely with those of the client. However, in other rulemakings, we have explored and implemented an alternative to the independent third party verification, where engineering design is the element we wish to ensure is examined and implemented without bias. This is the ''qualified professional engineer'' model. In the ''Resource Conservation and Recovery Act (RCRA) Burden Reduction Initiative'' (Burden Reduction Rule) (71 FR 16826, April 4, 2006) and the ''Oil Pollution Prevention and Response; Non-Transportation-Related Onshore and Offshore Facilities rule (67 FR 47042, July 17, 2002), the Agency came to similar conclusions. First, that professional engineers, whether independent or employees of a facility, being professionals, will uphold the integrity of their profession and only certify documents that meet the prescribed regulatory requirements and that the integrity of both the professional engineer and the professional oversight of boards licensing professional engineers are sufficient to prevent any abuses. And second, that in-house professional engineers may be the persons most familiar with the design and operation of the facility and that a restriction on in-house professional certifications might place an undue and unnecessary financial burden on owners or operators of facilities by forcing them to hire an outside engineer. Also in the ''Burden Reduction Rule'' the Agency concluded that a professional engineer is able to give fair and technical review because of the oversight programs established by the state licensing boards that will subject the professional engineer to penalties, including the loss of license and potential fines if certifications are provided when the facts do not warrant it. A qualified professional engineer maintains the most important components of any certification requirement: (1) That the engineer be qualified to perform the task based on training and experience; and (2) that she or he be a professional engineer licensed to practice engineering under the title Professional Engineer which requires following a code of ethics with the potential of losing his/her license for negligence (see 71 FR 16868, April 4, 2006). The personal liability of the professional engineer provides strong support for both the requirement that certifications must be performed by licensed professional engineers. The Agency is convinced that an employee of a facility, who is a qualified professional engineer and who has been licensed by a state licensing board, would be no more likely to be biased than a qualified professional engineer who is not an employee of the owner or operator. The EPA has concluded that the programs established by state licensing boards provide sufficient guarantees that a professional engineer, regardless of whether he/she is ''independent'' of the facility, will give a fair technical review. As an additional protection, the Agency has re-evaluated the design criteria for closed vent systems to ensure that the requirements are sufficiently objective and technically precise, while providing site specific flexibility, that a qualified professional engineer will be able to certify that they have been met.

It is important to reiterate that state licensing boards can investigate complaints of negligence or incompetence on the part of professional engineers and may impose fines and other disciplinary actions, such as cease-and-desist orders or license revocation. (See 71 FR 16868.) In light of the third party oversight provided by the state licensing boards in combination with the numerous recordkeeping and recording requirements established in this rule, the Agency is confident that abuses of the certification requirements will be minimal and that human health and the environment will be protected.

In other rulemakings, which have allowed for a qualified professional engineer in lieu of an independent reviewer, the Agency has required that the professional engineer be licensed in the state in which the facility is located. (See ''Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities; Final Rule'' (Coal Ash Rule) (80 FR 21302, April 17, 2015)). The Agency has made this decision, in that rule, for a number of reasons, but primarily because state licensing boards can provide the necessary oversight on the actions of the professional engineer and investigate complaints of negligence or incompetence as well as impose fines and other disciplinary actions such as cease-and-desist orders or license revocation. The Agency concluded that oversight may not be as rigorous if the professional engineer is operating under a license issued from another state. While we believe this is the appropriate outcome for the Coal Ash Rule, in part due to the regional and geological conditions specific to the landfill design, we do not believe that we need to provide this restriction for the closed vent system design under this rulemaking. Closed vent system design elements are not predicated on regional characteristics but instead follow generally and widely understood engineering analysis such as volumetric flow, back pressure and pressure drops. We do believe that the professional engineer should be licensed in a minimum of one of the states in which the certifying official does business.

Whether to specify independent third-party reporting, some other type of third-party or self-reporting, or a Professional Engineer is a case-specific decision that will vary depending on the nature of the rule, the characteristics of the sector(s) and regulated entities, and the applicable regulatory requirements. Based on all relevant factors for this rule, the EPA has determined that a qualified Professional Engineer approach is appropriate and that it is unnecessary to require the individual making certifications under this rule to be ''independent third parties.'' Thus the final rule does not prohibit an employee of the facility from making the certification, provided they are a professional engineer that is licensed by a state licensing board.

3. The EPA's Authority and Costs for Standards Reflecting Next Generation Compliance and Rule Effectiveness

Comment: Several commenters believe that standards reflecting Next Generation Compliance and rule effectiveness strategies discussed in the preamble to the proposed rule are not legal and represent an overreach of its authority. While the EPA has authority to require reasonable recordkeeping, reporting and monitoring under the CAA, there is nothing in the CAA that can be construed to authorize the EPA to force the regulated community to hire a third-party contractor to do the EPA's work. The commenters point out that the EPA admitted in the preamble to the 2011 proposal of subpart OOOO that ensuring compliance with the well completion requirements would be very difficult and burdensome for regulatory agencies. The commenters believe that the EPA is using the requirements to relieve the regulatory agencies of some of this burden. One commenter stated that the requirements amount to an unfunded enforcement mandate on the facilities it is supposed to be regulating.

The commenters also state that the compliance requirements would violate the Anti-Deficiency Act because the third-party verification requirements would circumvent budget appropriations for EPA enforcement activities (see 31 U.S.C. 1341(a)(1)(A)).

Some of the commenters also object to the EPA justifying increased monitoring, recordkeeping and reporting requirements on consent decrees in enforcement actions. The commenters point out that consent decrees impose more stringent requirements on facilities that have been found to be in violation of a regulatory requirement; therefore, consent decree requirements would be inappropriate for generally applicable regulations. The commenters state that the EPA has provided no justification for imposing heightened requirements on all facilities regardless of their compliance history.

Several commenters also state that the EPA must propose the regulatory language for all of the compliance provisions reflecting Next Generation Compliance and rule effectiveness strategies before they can be finalized and doing otherwise would raise a notice and comment issue. One commenter added that the EPA's intent is to apply such compliance requirements to more industries than just oil and natural gas production. Therefore, the EPA must separately propose the compliance requirements in their entirety, including estimated costs and benefits, before using them in any specific rulemakings.

Many commenters believe the standards reflecting Next Generation and rule effectiveness strategies will add significant labor and cost burdens over and above the compliance costs that the EPA already estimated for complying with the proposed rule. For example, one commenter calculates that their company will have to generate 270,000 closed vent system monthly inspection reports in the first five years of the rule if current requirements are finalized. Another commenter estimates the cost of installing continuous pressure monitoring equipment at a single site to be $20,000, resulting in potential company-wide costs of about $15 million. One commenter adds, based on their own experience with third-party auditors, the cost of an audit can range from $8,000 to $15,000 per audit, per facility. In general, the commenters state that the compliance requirements raise technical and operational complexities which can only result in increased costs. Some of the commenters note that these costs would be untenable for small businesses.

Some of the commenters also expressed concern about a lack of necessary IT infrastructure, such as data acquisition hardware, data management software, and appropriate software, at remote oil and natural gas production and transmission facilities. The commenters also point out the lack of electricity at these sites. The commenters point out that dealing with these issues further increase the costs associated with these compliance measures.

Response: The EPA believes that the comment regarding our legal authority may be based upon a misunderstanding of EPA's Next Generation Compliance and rule effectiveness strategies. The EPA describes these strategies as follows:

''Today's pollution challenges require a modern approach to compliance, taking advantage of new tools and approaches while strengthening vigorous enforcement of environmental laws. Next Generation Compliance is EPA's integrated strategy to do that, designed to bring together the best thinking from inside and outside EPA.'' [106] Among the referenced modern approaches to compliance is to ''[d]esign regulations and permits that are easier to implement, with a goal of improved compliance and environmental outcomes.''

Thus EPA's Next Generation Compliance and rule effectiveness strategies, in and of themselves, impose no requirements or obligations on the regulated community. The strategies establish no regulatory terms for any sector or facility nor create rights or responsibilities in any party. Rather, the strategies describe general compliance assurance and regulatory design principles, approaches, and tools that EPA may consider in conducting rulemaking, permitting, and compliance assurance, and enforcement activities.

Regarding comments that in order to avoid notice and comment issues the EPA must propose regulatory language before finalizing any regulatory language, the EPA disagrees. Section 307(d)(3) of the CAA states that ''notice of proposed rulemaking shall be published in the **Federal Register**, as provided under section 553(b) of title 5, United States Code . . . .'' There is nothing in the remainder of section 307(d) that requires the EPA to publish the regulatory text. Similarly, section 553(b) of the Administrative Procedure Act (APA) does not require agencies to publish the actual regulatory text. See EMILY's List v. FEC, 362 F. Supp. 2d 43, 53 (D.D.C. 2005), where ''[t]he Court notes that section 553 itself does not require the Agency to publish the text of a proposed rule, since the Agency is permitted to publish 'either the terms or substance of the proposed rule or a description of the subjects and issues involved.' ''. For this rulemaking, the EPA has provided notice and opportunity to comment for all of the specific regulatory requirements applicable to the sector and facilities covered by the rulemaking, either through proposed regulatory language or a description in the preamble.

The EPA notes that the proposal for independent third party verification—replaced in the final rule with qualified Professional Engineer requirements—reflects the responsibility of regulated entities to comply with the new NSPS. CAA Section 111(a)(1) defines ''a standard of performance'' as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirement) the Administrator determines has been adequately demonstrated.'' Further, in directing the Administrator to propose and promulgate regulations under section 111(b)(1)(B), Congress provided that the Administrator should take comment and then finalize the standards with such modifications ''as he deems appropriate.'' The D.C. Circuit has considered similar statutory phrasing from CAA section 231(a)(3) and concluded that ''[t]his delegation of authority is both explicit and extraordinarily broad.'' National Assoc. of Clean Air Agencies v. EPA, 489 F.3d 1221, 1229 (D.C. Cir. 2007).

In addition, the information to be collected for the proposed NSPS is based on notification, performance tests, recordkeeping and reporting requirements which will be mandatory for all operators subject to the final standards. Recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414) which provides that for ''any standard of performance under section 7411,'' the Administrator may require the sources to, among other things, ''install, use, and maintain such monitoring equipment, and use such audit procedures, or methods'' and submit compliance certifications in accordance with subsection (a)(3) of this section,'' as the Administrator may require. CAA section 114(a)(1)(A)–(G).

As discussed in section VI and in this section, the EPA has determined that to comply with the new NSPS and meet its

[106] USEPA; Next Generation Compliance Web page at *https://www.epa.gov/compliance/next-generation-compliance*.

emissions standard, regulated entities must obtain certifications from qualified Professional Engineers to demonstrate technical infeasibility to connect a pneumatic pump to an existing control device and to ensure the proper closed vent system design. The EPA believes for the sources covered by this rule, a professional engineer can furnish more, and sometimes better, data about regulatory compliance, especially where engineering design (*e.g.*, closed vent system design) is the element we want to ensure is examined and implemented without bias.

The EPA notes that nothing in this rule relieves the EPA of any of its responsibilities under the CAA or implies that the EPA will not continue to use its enforcement authorities under the CAA or devote resources to monitoring and enforcing this rule. This rule simply ensures that regulated parties will have the tools available to assess and ensure their own compliance.

The EPA wishes to explain that unfunded mandates are typically rules that impose significant obligations, without funding, on state, local, or tribal governments.[107] Interpreting this comment as applying to the obligations this NSPS imposes on entities to which it will apply, all rules, by definition, impose some obligations and responsibilities on subject facilities. In this preamble, the EPA explains the benefits, costs, and justification for each regulatory requirement.

As discussed above, the EPA explains the emission standards in this NSPS apply to the subject regulated entities. The EPA remains responsible for ensuring and enforcing compliance with the rule. The EPA notes that nothing in this rule relieves the EPA of any of its responsibilities under the CAA to ensure and enforce regulatory compliance.

The EPA agrees, that if the EPA were to seek to apply the standards in this rule—or any other regulatory standards, reflecting the Agency's Next Generation Compliance and rule effectiveness strategies or otherwise—to additional sectors beyond oil and natural gas production, the EPA would need to separately propose and justify the standards. As discussed above, however, the EPA's Next Generation Compliance and rule effectiveness strategies, in and of themselves, impose no requirements on the regulated community. The strategies prescribe no specific regulatory terms for any sector or facility nor do they create rights or responsibilities in any party. Rather, they describe compliance assurance and regulatory design strategies and approaches that the EPA will consider in conducting rulemaking, permitting, and compliance assurance, and enforcement activities that are inappropriate for notice and comment rulemaking. If the EPA believes that these strategies and approaches should be applied in other circumstances and to other industry sectors, the Agency will do this through other regulatory actions.

The EPA agrees with the commenters that certain of the Next Generation and rule effectiveness strategies are the result of information that the Agency has gained from implementation of past consent decrees (*e.g.*, closed vent system design and fugitives monitoring program audit). It is not unusual for the Agency to require additional monitoring practices, and recordkeeping and reporting requirements through consent, as this provides us an opportunity to identify the effectiveness of these standards from those companies that have engaged in violative conduct. Furthermore, through our enforcement efforts, when we see common and widespread compliance problems that can be addressed through improved monitoring, reporting and recordkeeping practices, it is our duty to include these tools in rulemaking, resulting in greater environmental benefit. As discussed elsewhere in this preamble, we are not requiring an ''independent third party'' verification of closed vent system design, nor are we requiring that the fugitive emissions monitoring program be audited. However, because of the widespread issues we have found with closed vent system design, the Agency will require a certification by a qualified professional engineer.

Regarding the comment about necessary IT infrastructure, such as data acquisition hardware, data management software, and appropriate software, at remote oil and natural gas production and transmission facilities and the lack of electricity at these sites, the Agency does not believe that the next generation and rule effectiveness initiatives we are proposing directly require IT infrastructure beyond that already required by other aspects of the rule. Likewise, onsite electrical availability for remote well sites is not an issue for the Next Generation and Rule Effectiveness strategies that we are finalizing.

IX. Impacts of the Final Amendments

A. What are the air impacts?

For this action, the EPA estimated the emission reductions that will occur due to the implementation of the final emission limits. The EPA estimated emission reductions based on the control technologies proposed as the BSER. This analysis estimates regulatory impacts for the analysis years of 2020 and 2025. The analysis of 2020 represents the accumulation of new and modified sources from the first full year of compliance, 2016, through 2020 to illustrate the near-term impacts of the rule. The regulatory impact estimates for 2020 include sources newly affected in 2020 as well as the accumulation of affected sources from 2016 to 2019 that are also assumed to be in continued operation in 2020, thus incurring compliance costs and emissions reductions in 2020. We also estimate impacts in 2025 to illustrate the continued compound effect of this rule over a longer period. The regulatory impact estimates for 2025 include sources newly affected in 2025 as well as the accumulation of affected sources from 2016 to 2024 that are also assumed to be in continued operation in 2025, thus incurring compliance costs and emissions reductions in 2025.

In 2020, we have estimated that the final NSPS would reduce about 300,000 tons of methane emissions and 150,000 tons of VOC emissions from affected facilities. In 2025, we have estimated that the proposed NSPS would reduce about 510,000 tons of methane emissions and 210,000 tons of VOC emissions from affected facilities. The NSPS is also expected to concurrently reduce about 1,900 tons HAP in 2020 and 3,900 tons HAP in 2025.

As described in the TSD and RIA for this rule, the EPA projected affected facilities using a combination of historical data from the United States GHG Inventory, and projected activity levels, taken from the Energy Information Administration (EIA's) Annual Energy Outlook (AEO). The EPA also considered state regulations with similar requirements to the final NSPS in projecting affected sources for impacts analyses supporting this rule.

B. What are the energy impacts?

Energy impacts in this section are those energy requirements associated with the operation of emission control devices. Potential impacts on the national energy economy from the rule are discussed in the economic impacts section. There would be little national energy demand increase from the operation of any of the environmental

[107] See USEPA, Rulemakings by Effect: Unfunded Mandates Web site at *https://yosemite.epa.gov/opei/rulegate.nsf/content/effectsunfunded.html?OpenDocument&Count=1000&ExpandView*.

controls expected to be used for compliance with the final NSPS.

The final NSPS encourages the use of emission controls that recover hydrocarbon products, such as methane, that can be used onsite as fuel or reprocessed within the production process for sale. We estimate that the standards will result in a total cost of about $320 million in 2020 and $530 million in 2025 (in 2012 dollars).

C. What are the compliance costs?

The EPA estimates the total capital cost of the final NSPS will be $250 million in 2020 and $360 million in 2025. The estimate of total annualized engineering costs of the final NSPS is $390 million in 2020 and $640 million in 2025. This annual cost estimate includes capital, operating, maintenance, monitoring, reporting, and recordkeeping costs. This estimated annual cost does not take into account any producer revenues associated with the recovery of salable natural gas. The EPA estimates that about 16 billion cubic feet in 2020 and 27 billion cubic feet of natural gas in 2025 will be recovered by implementing the NSPS. In the engineering cost analysis, we assume that producers are paid $4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. After accounting for these revenues, the estimate of total annualized engineering costs of the final NSPS are estimated to be $320 million in 2020 and $530 million in 2025.[108] The price assumption is influential on estimated annualized engineering costs. A simple sensitivity analysis indicates $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $16 million in 2020 and $27 million in 2025.

D. What are the economic and employment impacts?

The EPA used the National Energy Modeling System (NEMS) to estimate the impacts of the final rule on the United States energy system. The NEMS is a publically-available model of the United States energy economy developed and maintained by the EIA and is used to produce the AEO, a reference publication that provides detailed forecasts of the United States energy economy.

The EPA estimate that natural gas and crude oil drilling levels decline slightly over the 2020 to 2025 period relative to the baseline (by about 0.17 percent for natural gas wells and about 0.02 percent for crude oil wells). Natural gas production decreases slightly over the 2020 to 2025 period relative to the baseline (by about 0.03 percent), while crude oil production does not vary appreciably. Crude oil wellhead prices for onshore lower 48 production are not estimated to change appreciably over the 2020 to 2025 period relative to the baseline. However, wellhead natural gas prices for onshore lower 48 production are estimated to increase slightly over the 2020 to 2025 period relative to the baseline (about 0.20 percent). Net imports of natural gas are estimated to increase slightly over the 2020 to 2025 period relative to the baseline (by about 0.11 percent). Crude oil net imports are not estimated to change appreciably over the 2020 to 2025 period relative to the baseline.

Executive Order 13563 directs federal agencies to consider the effect of regulations on job creation and employment. According to the Executive Order, ''our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation. It must be based on the best available science.'' (Executive Order 13563, 2011) While a standalone analysis of employment impacts is not included in a standard benefit-cost analysis, such an analysis is of particular concern in the current economic climate given continued interest in the employment impact of regulations such as this final rule.

The EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment, control activities, and labor associated with new reporting and recordkeeping requirements. We estimated up-front and continual, annual labor requirements by estimating hours of labor required for compliance and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). The up-front labor requirement to comply with the proposed NSPS is estimated at about 270 FTEs in both 2020 and 2025. The annual labor requirement to comply with final NSPS is estimated at about 1,100 FTEs in 2020 and 1,800 FTEs in 2025.

We note that this type of FTE estimate cannot be used to identify the specific number of employees involved or whether new jobs are created for new employees versus displacing jobs from other sectors of the economy.

E. What are the benefits of the final standards?

The final rule is expected to result in significant reductions in emissions. In 2020, the final rule is anticipated to reduce 300,000 short tons, or 280,000 metric tons, of methane (a GHG and a precursor to tropospheric ozone formation), 150,000 tons of VOC (a precursor to both PM (2.5 microns and less) ($PM_{2.5}$) and ozone formation), and 1,900 tons of HAP. In 2025, the final rule is anticipated to reduce 510,000 short tons (460,000 metric tons) of methane, 210,000 tons of VOC, and 3,900 tons of HAP. These pollutants are associated with substantial health effects, climate effects, and other welfare effects.

The final standards are expected to reduce methane emissions annually by about 6.9 million metric tons CO_2 Eq. in 2020 and by about 11 million metric tons CO_2 Eq. in 2025. It is important to note that the emission reductions are based upon predicted activities in 2020 and 2025; however, the EPA did not forecast sector-level emissions in 2020 and 2025 for this rulemaking. To give a sense of the magnitude of the reductions, the methane reductions expected in 2020 are equivalent to about 2.8 percent of the methane emissions for this sector reported in the United States GHG Inventory for 2014 (about 232 million metric tons CO Eq. from petroleum and natural gas production and gas processing, transmission, and storage). Expected reductions in 2025 are equivalent to around 4.7 percent of 2014 emissions. As it is expected that emissions from this sector would increase over time, the estimates compared against the 2014 emissions would likely overestimate the percent of reductions from total emissions in 2020 and 2025.

Methane is a potent GHG that, once emitted into the atmosphere, absorbs terrestrial infrared radiation that contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form tropospheric ozone and stratospheric water vapor, both of which also contribute to global warming. When accounting for the impacts of changing methane, tropospheric ozone, and stratospheric water vapor concentrations, the Intergovernmental Panel on Climate Change (IPCC) 5th Assessment Report (2013) found that historical emissions of methane accounted for about 30 percent of the total current warming influence (radiative forcing) due to historical emissions of GHGs. Methane is therefore a major contributor to the climate

[108] To the extent that NSPS affected facilities would have controlled emissions voluntarily through the Methane Challenge or other initiatives, the estimated costs and benefits of the NSPS would be lower than those included in the RIA analysis.

change impacts described previously. In 2013, total methane emissions from the oil and natural gas industry represented nearly 29 percent of the total methane emissions from all sources and account for about 3 percent of all CO_2-equivalent emissions in the United States, with the combined petroleum and natural gas systems being the largest contributor to United States anthropogenic methane emissions.

We calculated the global social benefits of methane emission reductions expected from the final NSPS standards for oil and natural gas sites using estimates of the social cost of methane (SC–CH_4), a metric that estimates the monetary value of impacts associated with marginal changes in methane emissions in a given year. The SC–CH_4 estimates applied in this analysis were developed by Marten et al. (2014) and are discussed in greater detail below.

A similar metric, the social cost of CO_2 (SC–CO_2), provides important context for understanding the Marten et al. SC–CH_4 estimates.[109] The SC–CO_2 is a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. Similar to the SC–CH_4, it includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. Estimates of the SC–CO_2 have been used by the EPA and other federal agencies to value the impacts of CO_2 emissions changes in benefit cost analysis for GHG-related rulemakings since 2008.

The SC–CO_2 estimates were developed over many years, using the best science available, and with input from the public. Specifically, an interagency working group (IWG) that included the EPA and other executive branch agencies and offices used three integrated assessment models (IAMs) to develop the SC–CO_2 estimates and recommended four global values for use in regulatory analyses. The SC–CO_2 estimates were first released in February 2010 and updated in 2013 using new versions of each IAM. The 2010 SC–CO_2 Technical Support Document (2010 TSD) provides a complete discussion of the methods used to develop these estimates and the current SC–CO_2 TSD presents and discusses the 2013 update (including recent minor technical corrections to the estimates).[110]

The SC–CO_2 TSDs discuss a number of limitations to the SC–CO_2 analysis, including the incomplete way in which the IAMs capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. Currently, IAMs do not assign value to all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature due to a lack of precise information on the nature of damages and because the science incorporated into these models understandably lags behind the most recent research. Nonetheless, these estimates and the discussion of their limitations represent the best available information about the social benefits of CO_2 reductions to inform benefit-cost analysis. The EPA and other agencies continue to engage in research on modeling and valuation of climate impacts with the goal to improve these estimates and continue to consider feedback on the SC–CO_2 estimates from stakeholders through a range of channels, including public comments on Agency rulemakings, a separate Office of Management and Budget (OMB) public comment solicitation, and through regular interactions with stakeholders and research analysts implementing the SC–CO_2 methodology. See the RIA of this rule for additional details.

A challenge particularly relevant to this rule is that the IWG did not estimate the social costs of non-CO_2 GHG emissions at the time the SC–CO_2 estimates were developed. In addition, the directly modeled estimates of the social costs of non-CO_2 GHG emissions previously found in the published literature were few in number and varied considerably in terms of the models and input assumptions they employed [111] (EPA 2012). In the past, EPA has sought to understand the potential importance of monetizing non-CO_2 GHG emissions changes through sensitivity analysis using an estimate of the GWP of methane to convert emission impacts to CO_2 equivalents, which can then be valued using the SC–CO_2 estimates. This approach approximates the social cost of methane (SC–CH_4) using estimates of the SC–CO_2 and the GWP of methane.[112]

The published literature documents a variety of reasons that directly modeled estimates of SC–CH_4 are an analytical improvement over the estimates from the GWP approximation approach. Specifically, several recent studies found that GWP-weighted benefit estimates for methane are likely to be lower than the estimates derived using directly modeled social cost estimates for these gases.[113] The GWP reflects only the relative integrated radiative forcing of a gas over 100 years in comparison to CO_2. The directly modeled social cost estimates differ from the GWP-scaled SC–CO_2 because the relative differences in timing and magnitude of the warming between gases are explicitly modeled, the non-linear effects of temperature change on economic damages are included, and rather than treating all impacts over a hundred years equally, the modeled damages over the time horizon considered (300 years in this case) are discounted to present value terms. A detailed discussion of the limitations of the GWP approach can be found in the RIA.

In general, the commenters on previous rulemakings strongly encouraged the EPA to incorporate the monetized value of non-CO_2 GHG impacts into the benefit cost analysis. However, they noted the challenges associated with the GWP approach, as discussed above, and encouraged the use of directly modeled estimates of the SC–CH_4 to overcome those challenges.

Since then, a paper by Marten et al. (2014) has provided the first set of published SC–CH_4 estimates in the peer-reviewed literature that are consistent with the modeling assumptions underlying the SC–CO_2 estimates.[114] [115]

---

[109] Previous analyses have commonly referred to the social cost of carbon dioxide emissions as the social cost of carbon or SCC. To more easily facilitate the inclusion of non-CO_2 GHGs in the discussion and analysis the more specific SC–CO_2 nomenclature is used to refer to the social cost of CO_2 emissions.

[110] Both the 2010 SC–CO_2 TSD and the current TSD are available at: *https://www.whitehouse.gov/omb/oira/social-cost-of-carbon*.

[111] U.S. EPA. 2012. Regulatory Impact Analysis Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. April. *http://www.epa.gov/ttn/ecas/regdata/RIAs/oil_natural_gas_final_neshap_nsps_ria.pdf.* Accessed March 30, 2015.

[112] For example, see (1) U.S. EPA. (2012). ''Regulatory impact analysis supporting the 2012 U.S. Environmental Protection Agency final new source performance standards and amendments to the national emission standards for hazardous air pollutants for the oil and natural gas industry.'' Retrieved from *http://www.epa.gov/ttn/ecas/regdata/RIAs/oil_natural_gas_final_neshap_nsps_ria.pdf* and (2) U.S. EPA. (2012). ''Regulatory impact analysis: Final rulemaking for 2017–2025 light-duty vehicle greenhouse gas emission standards and corporate average fuel economy standards.'' Retrieved from *http://www.epa.gov/otaq/climate/documents/420r12016.pdf*.

[113] See Waldhoff et al. (2011); Marten and Newbold (2012); and Marten et al. (2014).

[114] Marten et al. (2014) also provided the first set of SC–N_2O estimates that are consistent with the assumptions underlying the IWG SC–CO_2 estimates.

Continued

Specifically, the estimation approach of Marten et al. used the same set of three IAMs, five socioeconomic and emissions scenarios, equilibrium climate sensitivity distribution, three constant discount rates, and aggregation approach used by the IWG to develop the SC–CO_2 estimates.

The SC–CH_4 estimates from Marten et al. (2014) are presented below in Table 8. More detailed discussion of the SC–CH_4 estimation methodology, results and a comparison to other published estimates can be found in the RIA and in Marten et al.

TABLE 8—SOCIAL COST OF CH_4, 2012–2050 [a]

[In 2012$ per metric ton] (Source: Marten et al., 2014 [b])

Year	SC–CH_4			
	5% Average	3% Average	2.5% Average	3% 95th percentile
2012	$430	$1000	$1400	$2800
2015	490	1100	1500	3000
2020	580	1300	1700	3500
2025	700	1500	1900	4000
2030	820	1700	2200	4500
2035	970	1900	2500	5300
2040	1100	2200	2800	5900
2045	1300	2500	3000	6600
2050	1400	2700	3300	7200

Notes:

[a] There are four different estimates of the SC–CH_4, each one emissions-year specific. The first three shown in the table are based on the average SC–CH_4 from three integrated assessment models at discount rates of 5, 3, and 2.5 percent. The fourth estimate is the 95th percentile of the SC–CH_4 across all three models at a 3 percent discount rate. See RIA for details.

[b] The estimates in this table have been adjusted to reflect the minor technical corrections to the SC–CO_2 estimates described above. See the Corrigendum to Marten et al. (2014), *http://www.tandfonline.com/doi/abs/10.1080/14693062.2015.1070550.*

The application of these directly modeled SC–CH_4 estimates from Marten et al. (2014) in a benefit-cost analysis of a regulatory action is analogous to the use of the SC–CO_2 estimates. In addition, the limitations for the SC-CO_2 estimates discussed above likewise apply to the SC–CH_4 estimates, given the consistency in the methodology.

In early 2015, the EPA conducted a peer review of the application of the Marten et al. (2014) non-CO_2 social cost estimates in regulatory analysis and received responses that supported this application. See the RIA for a detailed discussion.

The EPA also carefully considered the full range of public comments and associated technical issues on the Marten et al. SC–CH_4 estimates received through this rulemaking. The comments addressed the technical details of the SC–CO_2 estimates and the Marten et al. SC–CH_4 estimates as well as their application to this rulemaking analysis. The commenters also provided constructive recommendations to improve the SC–CO_2 and SC–CH_4 estimates in the future. Based on the evaluation of the public comments on this rulemaking, the favorable peer review of the Marten et al. application, and past comments urging the EPA to value non-CO_2 GHG impacts in its rulemakings, the EPA concluded that the estimates represent the best scientific information on the impacts of climate change available in a form appropriate for incorporating the damages from incremental methane emissions changes into regulatory analysis. The EPA has included those benefits in the main benefits analysis. See the RTC document for the complete response to comments received on the SC-CH_4 as part of this rulemaking.

The methane benefits calculated using Marten et al. (2014) are presented in Table 9 for years 2020 and 2025. Applying this approach to the methane reductions estimated for the NSPS, the 2020 methane benefits vary by discount rate and range from about $160 million to approximately $960 million; the mean SC–CH_4 at the 3-percent discount rate results in an estimate of about $360 million in 2020. The methane benefits increase in the 2025, ranging from $320 million to $1.8 billion, depending on discount rate used; the mean SC–CH_4 at the 3-percent discount rate results in an estimate of about $690 million in 2025.

TABLE 9—ESTIMATED GLOBAL BENEFITS OF METHANE REDUCTIONS

[In millions, 2012$]

Discount rate and statistic	Year	
	2020	2025
Million metric tonnes of methane reduced	0.28	0.46
Million metric tonnes of CO_2 Eq.	6.9	11
5% (average)	$160	$320
3% (average)	$360	$690
2.5% (average)	$480	$890
3% (95th percentile)	$960	$1,800

[115] Marten, A.L., E.A. Kopits, C.W. Griffiths, S.C. Newbold & A. Wolverton (2014, online publication; 2015, print publication). Incremental CH_4 and N_2O mitigation benefits consistent with the United States Government's SC–CO_2 estimates, Climate Policy, DOI: 10.1080/14693062.2014.912981.

In addition to the limitation discussed above, and the referenced documents, there are additional impacts of individual GHGs that are not currently captured in the IAMs used in the directly modeled approach of Marten et al. (2014) and, therefore, not quantified for the rule. For example, in addition to being a GHG, methane is a precursor to ozone. The ozone generated by methane has important non-climate impacts on agriculture, ecosystems, and human health. The RIA describes the specific impacts of methane as an ozone precursor in more detail and discusses studies that have estimated monetized benefits of these methane generated ozone effects. The EPA continues to monitor developments in this area of research.

With the data available, we are not able to provide credible health benefit estimates for the reduction in exposure to HAP, ozone and $PM_{2.5}$ for these rules, due to the differences in the locations of oil and natural gas emission points relative to existing information and the highly localized nature of air quality responses associated with HAP and VOC reductions. This is not to imply that there are no benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available.[116] In addition to health improvements, there will be improvements in visibility effects, ecosystem effects and climate effects, as well as additional product recovery.

Although we do not have sufficient information or modeling available to provide quantitative estimates for this rulemaking, we include a qualitative assessment of the health effects associated with exposure to HAP, ozone and $PM_{2.5}$ in the RIA for this rule. These qualitative effects are briefly summarized below, but for more detailed information, please refer to the RIA, which is available in the docket. One of the HAP of concern from the oil and natural gas sector is benzene, which is a known human carcinogen. VOC emissions are precursors to both $PM_{2.5}$ and ozone formation. As documented in previous analyses (U.S. EPA, 2006 [117], U.S. EPA, 2010 [118], and U.S. EPA, 2014 [119]), exposure to $PM_{2.5}$ and ozone is associated with significant public health effects. $PM_{2.5}$ is associated with health effects, including premature mortality for adults and infants, cardiovascular morbidity such as heart attacks, and respiratory morbidity such as asthma attacks, acute bronchitis, hospital admissions and emergency room visits, work loss days, restricted activity days and respiratory symptoms, as well as visibility impairment.[120] Ozone is associated with health effects, including hospital and emergency department visits, school loss days and premature mortality, as well as injury to vegetation and climate effects.[121]

Finally, the control techniques to meet the standards are anticipated to have minor secondary emissions impacts, which may partially offset the direct benefits of this rule. The magnitude of these secondary air pollutant impacts is small relative to the direct emission reductions anticipated from this rule.

In particular, the EPA has estimated that an increase in flaring of natural gas in response to this rule will produce a variety of emissions, including about 1.0 million short tons of CO_2 in 2020 and about 1.2 million short tons of CO_2 in 2025. The EPA has not estimated the monetized value of the secondary emissions of CO_2 because much of the VOCs and methane that would have been released in the absence of the flare would have eventually oxidized into CO_2 in the atmosphere. Note that the CO_2 produced from the methane oxidizing in the atmosphere is not included in the calculation of the SC–CH_4.

For VOC emissions, the oxidization period is relatively short, on the order of a couple of weeks. However, for methane, the oxidization period is longer, on the order of a decade, and the EPA recognizes that because the growth rate of the SC-CO_2 estimates are lower than their associated discount rates, the estimated impact of CO_2 produced in the future via oxidized methane from fossil-based emissions may be less than the estimated impact of CO_2 released immediately from combustion. This would imply a small disbenefit associated with the earlier release of CO_2 during combustion of the methane emissions.

In the proposal, the EPA solicited comment on the appropriateness of monetizing the impact of the earlier release of CO_2 due to combusting methane emissions from oil and gas sites and an illustrative analysis that described a potential approach to approximate this value using the SC-CO_2. The EPA did not receive any comments regarding the appropriate methodology for conducting such an analysis, but did receive one comment letter that voiced general support for monetizing the secondary impacts. In consideration of this comment and recognizing the challenges and uncertainties related to estimation of these secondary emissions impacts for this rulemaking, EPA has continued to examine this issue in the context of this regulatory analysis (*i.e.,* the combusting of fossil-based methane at oil and gas sites) and explored ways to improve the illustrative analysis. See RIA for details.

X. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *http://www2.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is an economically significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an analysis of the potential

[116] Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with the effect that those emissions have on ambient $PM_{2.5}$ levels and the health effects associated with $PM_{2.5}$ exposure (Fann, Fulcher, and Hubbell, 2009). While these ranges of benefit-per-ton estimates can provide useful context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in that study are derived from total VOC emissions across all sectors. Coupled with the larger uncertainties about the relationship between VOC emissions and $PM_{2.5}$ and the highly localized nature of air quality responses associated with HAP and VOC reductions, these factors lead us to conclude that the available VOC benefit-per-ton estimates are not appropriate to calculate monetized benefits of these rules, even as a bounding exercise.

[117] U.S. EPA. *RIA. National Ambient Air Quality Standards for Particulate Matter,* Chapter 5. Office of Air Quality Planning and Standards, Research Triangle Park, NC. October 2006. Available on the Internet at *http://www.epa.gov/ttn/ecas/regdata/RIAs/Chapter%205—Benefits.pdf.*

[118] U.S. EPA. *RIA. National Ambient Air Quality Standards for Ozone.* Office of Air Quality Planning and Standards, Research Triangle Park, NC. January 2010. Available on the Internet at *http://www.epa.gov/ttn/ecas/regdata/RIAs/s1-supplemental_analysis_full.pdf.*

[119] U.S. EPA. *RIA. National Ambient Air Quality Standards for Ozone.* Office of Air Quality Planning and Standards, Research Triangle Park, NC. December 2014. Available on the Internet at *http://www.epa.gov/ttnecas1/regdata/RIAs/20141125ria.pdf.*

[120] U.S. EPA. *Integrated Science Assessment for Particulate Matter (Final Report).* EPA–600–R–08–139F. National Center for Environmental Assessment—RTP Division. December 2009. Available at *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546.*

[121] U.S. EPA. *Air Quality Criteria for Ozone and Related Photochemical Oxidants (Final).* EPA/600/R–05/004aF–cF. Washington, DC: U.S. EPA. February 2006. Available on the Internet at *http://cfpub.epa.gov/ncea/CFM/recordisplay.cfm?deid=149923.*

costs and benefits associated with this action.

In addition, the EPA prepared a Regulatory Impact Analysis (RIA) of the potential costs and benefits associated with this action. The RIA available in the docket describes in detail the empirical basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. Table 10 shows the results of the cost and benefits analysis for the final rule.

TABLE 10—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS AND NET BENEFITS FOR THE FINAL OIL AND NATURAL GAS NSPS IN 2020 AND 2025

[Millions of 2012$]

	2020	2025
Total Monetized Benefits [1]	$360 million	$690 million.
Total Costs [2]	$320 million	$530 million.
Net Benefits [3]	$35 million	$170 million.
Non-monetized Benefits	Non-monetized climate benefits. Health effects of $PM_{2.5}$ and ozone exposure from 150,000 tons of VOC in 2020 and 210,000 tons of VOC in 2025. Health effects of HAP exposure from 1,900 tons of HAP in 2020 and 3,900 tons of HAP in 2025. Health effects of ozone exposure from 300,000 tons of methane in 2020 and 510,000 tons methane in 2025. Visibility impairment. Vegetation effects.	

[1] We estimate methane benefits associated with four different values of a one ton methane reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). For the purposes of this table, we show the benefits associated with the model average at 3 percent discount rate, however we emphasize the importance and value of considering the full range of social cost of methane values. We provide estimates based on additional discount rates in preamble section IX.E and in the RIA. The CO_2-equivalent (CO_2 Eq.) methane emission reductions are 6.9 million metric tons in 2020 and 11 million metric tons in 2025. Also, the specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits.

[2] The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue from additional natural gas recovery as a result of the NSPS. When rounded, the cost estimates are the same for the 3 percent discount rate as they are for the 7 percent discount rate cost estimates, so rounded net benefits do not change when using a 3 percent discount rate.

[3] Figures may not sum due to rounding.

B. Paperwork Reduction Act (PRA)

The Office of Management and Budget (OMB) has previously approved the information collection activities contained in 40 CFR part 60, subpart OOOO under the PRA and has assigned OMB control number 2060–0673 and ICR number 2437.01; a summary can be found at 77 FR 49537. The information collection requirements in the final action titled, Standards of Performance for Crude Oil and Natural Gas Facilities for Construction, Modification, or Reconstruction (40 CFR part 60 subpart OOOOa) have been submitted for approval to the OMB under the PRA. The ICR document prepared by the EPA has been assigned EPA ICR Number 2523.01. You can find a copy of the ICR in the docket for this rule, and is briefly summarized below.

The information to be collected for the final NSPS is based on notification, performance tests, recordkeeping and reporting requirements which will be mandatory for all operators subject to the final standards. Recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). The information will be used by the delegated authority (state agency, or Regional Administrator if there is no delegated state agency) to ensure that the standards and other requirements are being achieved. Based on review of the recorded information at the site and the reported information, the delegated permitting authority can identify facilities that may not be in compliance and decide which facilities, records, or processes may need inspection. All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

Potential respondents under subpart OOOOa are owners or operators of new, modified or reconstructed oil and natural gas affected facilities as defined under the rule. None of the facilities in the United States are owned or operated by state, local, tribal or the Federal government. All facilities are privately owned for-profit businesses. The requirements in this action result in industry recording keeping and reporting burden associated with review of the requirements for all affected entities, gathering relevant information, performing initial performance tests and repeat performance tests if necessary, writing and submitting the notifications and reports, developing systems for the purpose of processing and maintaining information, and train personnel to be able to respond to the collection of information.

The estimated average annual burden (averaged over the first 3 years after the effective date of the standards) for the recordkeeping and reporting requirements in subpart OOOOa for the 2,554 owners and operators that are subject to the rule is 98,438 labor hours, with an annual average cost of $3,361,074. The annual public reporting and recordkeeping burden for this collection of information is estimated to average 20 hours per response. Respondents must monitor all specified criteria at each affected facility and maintain these records for 5 years. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act (RFA)

Pursuant to sections 603 and 609(b) of the RFA, the EPA prepared an initial regulatory flexibility analysis (IRFA) for the proposed rule and convened a Small Business Advocacy Review (SBAR) Panel to obtain advice and recommendations from small entity representatives that potentially would be subject to the rule's requirements. Summaries of the IRFA and Panel recommendations are presented in the proposed rule at 80 FR 56593.

As required by section 604 of the RFA, the EPA prepared a final regulatory flexibility analysis (FRFA) for this action. The FRFA addresses the issues raised by public comments on the IRFA for the proposed rule. The complete FRFA is available for review in the RIA in the public docket and is summarized here.

1. Statutory Authority

The legal authority for this rule stems from section 111 of the CAA, which requires the EPA to issue ''standards of performance'' for new sources in the list of categories of stationary sources that cause or contribute significantly to air pollution and which may reasonably be anticipated to endanger public health or welfare. See section III.A of this preamble for more information.

2. Significant Issues Raised and Agency Responses

The EPA received comments on the proposed standards related to the potential impacts on small entities and requests for comments that were included based on the SBAR Panel Recommendations. See sections VI and VIII of this preamble and the RTC Document in Docket ID EPA–HQ–OAR–2010–0505 for more detailed responses.

Low production wells: Several commenters supported the proposed exemption of low production well sites from the fugitive monitoring requirements. Commenters noted that marginal wells generate relatively low revenue and these wells are often drilled and operated by small companies.

Response: While these commenters did provide support for the proposed low production well exemption, other commenters indicated that low production well sites have the potential to emit substantial amounts of fugitive emissions, and that a significant number of wells would be excluded from fugitive emissions monitoring based on this exemption. We did not receive data showing that low production well sites have lower emissions than non-low production well sites. In fact, the data that were provided indicated that the potential emissions from these well sites could be as significant as the emissions from non-low production well sites since the type of equipment and the well pressures are more than likely the same. In discussions with stakeholders, they indicated that well site fugitive emissions are not based on production, but rather on the number of pieces of equipment and components. Therefore, we believe that the emissions from low production and non-low production well sites are comparable and we did not finalize the proposed exclusion of low production well sites from fugitive emissions monitoring.

REC costs: Commenters stated that small operators have higher well completion costs, and typically conduct completions less frequently. Generally, small operators lack the purchasing power to get the discounted prices service companies offer to larger operators. However, small entity commenters did not provide specific cost information.

Response: The BSER analysis is based on the averages of nationwide data. It is possible for a small operator to have higher than the nationwide average completion costs, however, the daily completion cost provided by the commenters is not significantly different than the EPA's estimate. Therefore, we do not believe that the cost of RECs disfavor small businesses.

Phase-in period for RECs: Commenters stated that the EPA should create a compliance phase-in period of at least 6 months for the REC requirements, to accommodate small operators. Commenters stated that REC equipment is in short supply, and this will drive up REC costs. Commenters stated that small entities lack the purchasing power of larger operators, which makes it difficult to obtain the needed equipment before the compliance period begins.

Response: We agree that compliance with the REC requirements in the final rule could be burdensome for some in the near term due to the unavailability of REC equipment. As discussed in section VI of the preamble, the final rule provides a phase-in approach that would allow a quick build-up of the REC supplies in the near term.

Alternatives to OGI technology: Several commenters indicated that the EPA should allow alternatives to OGI technology as the cost is excessive for small operators.

Response: In the final rule, the EPA is allowing Method 21 with a repair threshold of 500 ppm as an alternative to OGI. We believe this alternative will alleviate some of the burden on small entities.

Basing monitoring frequency on the percentage of leaking components: Commenters indicated that using a percentage of components, rather than a set number of components, to determine the frequency of surveys is also unfair to small entities since a small site will have fewer fugitive emission components than a larger site. Commenters stated that smaller entities are much more likely to operate these smaller sites, and thus are more likely to have higher frequency survey requirements under the percentage-based system.

Response: The EPA agrees that imposing a performance based monitoring schedule would require operators to develop a program that would require extensive administration to ensure compliance. We believe that the potential for a performance–based approach to encourage greater compliance is outweighed in this case by these additional burdens and the complexity it would add. Therefore, the EPA is finalizing a fixed monitoring frequency instead of performance based monitoring.

Timing of initial fugitive monitoring periods: Commenters stated that the requirement to conduct surveys for affected facilities using OGI technology within 30 days of the well completion or within 30 days of modification is overly restrictive. Additionally, commenters stated that small operators may not be able to find vendors available to survey a small number of wells within the required timeframe. One commenter stated that contractors will be in high demand and may give scheduling preference to larger clients versus small business entities.

Response: The EPA considered these and other comments and concluded that the proposed time of 30 days within a well completion or modification is not enough time to complete the necessary preparations for the initial monitoring survey. In addition, other commenters pointed out that first date of production should be the trigger, rather than the date of well completion. Therefore, for the collection of fugitive emissions components at a new or modified well site, we are finalizing that the initial monitoring survey must take place by June 3, 2017 or within 60 days of the startup of production, whichever is later. We believe this extended timeframe for compliance will alleviate some of the burden on smaller operators.

Third party compliance: Commenters believe that requiring third party compliance audits will be a significant burden on small entities. One commenter said that a third-party audit requirement will dramatically increase the costs of the program and have a negative competitive impact on smaller, less funded operators.

Response: While the EPA continues to believe that independent third party verification can furnish more, and sometimes better, data about regulatory compliance, we have explored alternatives to the independent third party verification. Specifically, the ''qualified professional engineer'' model was assessed to focus on the element of engineering design. The final rule requires a professional engineer certification of technical infeasibility of connecting a pneumatic pump to an existing control device, and a professional engineer design of closed vent systems. These certifications will ensure that the owner or operator has effectively assessed appropriate factors before making a claim of infeasibility and that the closed vent system is properly designed to verify that all emissions from the unit being controlled in fact reach the control device and allow for proper control. We believe this simplified approach will reduce the burden imposed on all affected facilities, including those owned by small businesses.

3. Affected Small Entities

To identify potentially affected entities under the proposed NSPS, the EPA combined information from industry databases to identify firms drilling and completing wells in 2012, as well as identified their oil and natural gas production levels for that year.

The analysis indicates about 2,031 small entities may be subject to the requirements for hydraulically fractured and re-fractured oil well completions and fugitive emissions requirements at well sites.

4. Reporting, Recordkeeping and Other Compliance Requirements

The information to be collected for the NSPS is based on notification, performance tests, recordkeeping and reporting requirements which will be mandatory for all operators subject to the final standards. The estimated average annual burden (averaged over the first 3 years after the effective date of the standards) for the recordkeeping and reporting requirements in subpart OOOOa for the 2,554 owners and operators that are subject to the rule is 98,438 labor hours, with an annual average cost of $3,361,074. The annual public reporting and recordkeeping burden for this collection of information is estimated to average 20 hours per response. Respondents must monitor all specified criteria at each affected facility and maintain these records for 5 years. Burden is defined at 5 CFR 1320.3(b).

The EPA summarized the potential regulatory cost impacts of the proposed rule and alternatives in Section 3 of the RIA. The analysis in the FRFA drew upon the same analysis and assumptions as the analyses presented in the RIA. The FRFA analysis is presented in its entirely in Section 6.3 of the RIA.

The EPA based the analysis in the FRFA on impacts estimates for the proposed requirements for hydraulically fractured and re-fractured oil well completions and well site fugitive emissions, which represent about 98 percent of the estimated compliance costs of the NSPS in 2020 and 2025. Not incorporating impacts from other provisions in this analysis underestimates impacts, but the EPA believes that detailed analysis of the two provisions impacts on small entities is illustrative of impacts on small entities from the rule in its entirety. The cost of compliance for small firms is estimated to be about $110 million in 2020 and $190 million in 2025.

We also estimate cost-to-sales ratios for small firms. For some firms, we estimate their 2012 sales levels by multiplying their 2012 oil and natural gas production levels reported in an industry database by the assumed oil and natural gas prices at the wellhead. For natural gas, we assumed the $4/Mcf for natural gas. For oil prices, we estimated revenues using two alternative prices, $70/bbl and $50/bbl. In the results, we call the case using $70/bbl the ''primary scenario'' and the case using the $50/bbl the ''low oil price scenario''. For projected 2020 and 2025 potentially affected activities, we allocated compliance costs across entities based upon the costs estimated in the TSD and used in the RIA.

The percent of small firms with cost-to-sales ratios greater than 1 percent and greater than 3-percent increase from 2020 to 2025 as affected sources accumulate under the NSPS. Cost-to-sales ratios exceeding 1 percent and 3 percent. Also, cost-to-sales ratios fall as the oil price falls from the main scenario to the low oil price scenario.

The analysis above is subject to a number of caveats and limitations. These are discussed in detail in the IRFA, as well as in Section 3 of the RIA.

5. Steps Taken To Minimize Impact on Small Entities

The EPA considered three major options for this rule. The finalized option includes reduced emission completion (REC) and completion combustion requirements for a subset of newly completed oil wells that are hydraulically fractured or refractured and requirements that fugitive emissions survey and repair programs be performed semiannually at affected well sites and quarterly at affected transmission and storage or compressor stations. One option examined includes an exemption from low production well site fugitive requirements, but was rejected because we believe that low production well sites have similar equipment and components as sites that are not categorized as low production. Without data supporting a difference in emissions between low production well sites and not low production well sites, the EPA believes exempting low production well sites would reduce the effectiveness of the rule, especially considering the high proportion of small firms in the industry. The more stringent option required quarterly monitoring for all sites under the fugitive emissions programs, which leads to greater emissions reductions, however it also increases net costs and results in lower net benefits compared to the finalized option.

Significant comments with regard to the small business analysis received by the EPA include the topics of low production well exemptions, well completion costs, compliance phase-in periods, alternatives to OGI technology, monitoring frequency and timing, and third party compliance.

Though all comments were seriously considered, the EPA is unable to incorporate all suggestions without compromising the effectiveness of the final regulation. Changes to the rule from proposal that may benefit small entities due to comments received include allowing both OGI and Method 21 as acceptable monitoring technology, replacing a performance based monitoring schedule with a fixed frequency, lengthening the time of initial fugitive monitoring from within 30 days to the later of either June 3, 2017 or within 60 days of the startup of production, whichever is later, and simplifying the third party verification of technical infeasibility requirements. Though these are not monetized, we believe the flexibility and simplifications these changes have added to the rule result in a reduced burden on small entities.

In addition, the EPA is preparing a Small Entity Compliance Guide to help small entities comply with this rule. The guide will be available on the World Wide Web 60 days after publication of the final rule at *https://www3.epa.gov/airquality/oilandgas/implement.html.*

D. Unfunded Mandates Reform Act of 1995 (UMRA)

This action contains a federal mandate under UMRA, 2 U.S.C. 1531–1538, that may result in expenditures of $100 million or more for state, local and tribal governments, in the aggregate, or the private sector in any one year. More specifically, this action contains a federal private sector mandate that may result in the expenditures of $100 million or more for the private section in any one year. Accordingly, the EPA has prepared the following written statement in compliance with sections 202 and 205 of UMRA. This rule is not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

1. Statutory Authority

The legal authority for this rule stems from section 111 of the CAA, which requires the EPA to issue ''standards of performance'' for new sources in the list of categories of stationary sources that cause or contribute significantly to air pollution and which may reasonably be anticipated to endanger public health or welfare. See section III.A of this preamble for more information.

2. Costs and Benefits

As discussed in sections II.A.3, IX.C and IX.E of this preamble, this rule results in a net benefit. Including the resources from recovered natural gas that would otherwise be vented, the quantified net benefits of the regulation are estimated to be $35 million in 2020 and $170 million in 2025 in 2012 dollars using a 3 percent discount rate for climate benefits. The estimated total annualized engineering costs of the final rule, accounting for the recovered natural gas are $320 million in 2020 and $530 million in 2025. The EPA estimates the final rule will lead to monetized benefits of about $360 million in 2020 and $690 million in 2025, at the model average at a 3 percent discount rate. More in depth information on costs and benefits, including non-monetized or quantified benefits, of the final regulation can be found in the RIA.

3. Effects on National Economy

As seen in section IX.D of this preamble, the EPA used the National Energy Modeling System (NEMS) to estimate the impacts of the final rule on the United States energy system. Estimates show slight declines in natural gas and crude oil drilling, and natural gas production over the 2020 to 2025 period under the rule, while wellhead natural gas prices are estimated to increase slightly over the 2020 to 2025 period under the rule. Crude oil production and crude oil wellhead prices are not estimated to change appreciably over the 2020 to 2025 period under the rule. Net imports of natural gas are estimated to increase slightly over the 2020 to 2025 period, while net imports of crude oil are not estimated to change appreciably.

Also discussed in section IX.D, the up-front labor requirement to comply with the proposed NSPS is estimated at about 270 FTEs in 2020 and 2025. The annual labor requirement to comply with final NSPS is estimated at about 1,100 FTEs in 2020 and 1,800 FTEs in 2025. For more in depth information on both the estimated energy markets impacts and estimated job creation and employment impacts of this rule, see the RIA.

4. Regulatory Alternatives

Alternate regulatory options examined in the RIA include decreasing fugitive survey requirements to annual at well sites and semiannual at all other affected locations (termed Option 1 in the RIA), and increasing fugitive survey frequency at all wells to quarterly (termed Option 3 in the RIA). The finalized regulation results in estimated net benefits of $35 million in 2020 and $170 million in 2025. Reducing fugitive survey requirements, Option 1, leads to lower costs as well as lower benefits and results in estimated net benefits of $54 million in 2020 and $180 million in 2025. Increasing the survey frequency leads to an increase in capital costs with a non-commensurate increase in monetized benefits, resulting in estimated net benefits of −$75 million in 2020, and −$38 million in 2025. Both of these regulatory options result in lower net benefits in 2025 compared to the finalized regulation. For a more in depth analysis of these options, see the RIA.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government. These final rules primarily affect private industry and would not impose significant economic costs on state or local governments.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Subject to Executive Order 13175 (65 FR 67249; November 9, 2000), the EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or the EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement.

The EPA has concluded that this action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law, thus Executive Order 13175 does not apply to this rule. The EPA believes that the affected facilities impacted by this rulemaking on tribal lands are owned by private entities, and tribes will not be directly impacted by the compliance costs associated with this rulemaking. There would only be tribal implications associated with this rulemaking in the case where a unit is owned by a tribal government or a tribal government is given delegated authority to enforce the rulemaking.

The EPA offered consultation with tribal officials early in the regulation development process to permit them an opportunity to have meaningful and timely input. Consultation letters were sent to the tribal leaders of 567 federally recognized tribes, provided information regarding this rule, and offered consultation. The EPA did not receive any requests for tribal consultation on this rulemaking. In addition, the EPA has conducted meaningful involvement with tribal stakeholders throughout the rulemaking process and provided an update on the Methane Strategy on the January 29, 2015 and September 10, 2015 National Tribal Air Association and EPA Air Policy monthly calls. Consistent with previous actions affecting the oil and natural gas sector, there is significant tribal interest because of the growth of the oil and natural gas production in Indian country. The EPA specifically solicited comment on the proposed action from tribal officials and considered comments received from tribal officials in the development of this final action. Please see the RTC document in the public docket.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

This action is subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it is an economically significant regulatory action as defined by Executive Order 12866, and the EPA believes that the environmental health or safety risk addressed by this action has a disproportionate effect on children. Accordingly, the Agency has evaluated the environmental health and welfare effects of climate change on children.

Greenhouse gases including methane contribute to climate change and are emitted in significant quantities by the oil and gas sector. The EPA believes that the GHG emission reductions resulting from implementation of these final rules will further improve children's health.

The assessment literature cited in the EPA's 2009 Endangerment Finding concluded that certain populations and life stages, including children, the elderly, and the poor, are most vulnerable to climate-related health effects. The assessment literature since 2009 strengthens these conclusions by providing more detailed findings regarding these groups' vulnerabilities and the projected impacts they may experience.

These assessments describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. In addition, children are among those especially susceptible to most allergic diseases, as well as health effects associated with heat waves, storms, and floods. Additional health concerns may arise in low income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households.

More detailed information on the impacts of climate change to human health and welfare is provided in section IV.B of this preamble.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211 (66 FR 28355, May 22, 2001) provides that agencies will prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget, a Statement of Energy Effects for certain actions identified as ''significant energy actions.'' Section 4(b) of Executive Order 13211 defines ''significant energy actions'' as any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: (1)(i) That is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.

This action is not a ''significant energy action'' as defined in Executive Order 13211 (66 FR 28355, May 22, 2001), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The basis for these determinations follows.

The EPA used the NEMS to estimate the impacts of the final rule on the United States energy system. The NEMS is a publically-available model of the United States energy economy developed and maintained by the Energy Information Administration of the DOE and is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the United States energy economy.

The EPA estimates that natural gas and crude oil drilling levels decline slightly over the 2020 to 2025 period under the final NSPS (by about 0.17 percent for natural gas wells and 0.02 percent for crude oil wells). Crude oil production does not vary appreciably under the rule, while natural gas production declines slightly over the 2020 to 2025 period (about 0.03 percent). Crude oil wellhead prices for onshore lower 48 production are not estimated to change appreciably over the 2020 to 2025 period. However, wellhead natural gas prices for onshore lower 48 production are estimated to increase slightly over the 2020 to 2025 period (about 0.20 percent). Net imports of natural gas are estimated to increase slightly in 2020 (by about 0.12 percent) and in 2025 (by about 0.11 percent). Crude oil net imports are not estimated to change in 2020, but decrease slightly in 2025 (by about 0.02 percent). Net imports of crude oil do not change appreciably over the 2020 to 2025 period.

Additionally, the NSPS establishes several performance standards that give regulated entities flexibility in determining how to best comply with the regulation. In an industry that is geographically and economically heterogeneous, this flexibility is an important factor in reducing regulatory burden. For more information on the estimated energy effects of this final rule, please see the Regulatory Impact Analysis, which is in the docket for this rule.

I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

This action involves technical standards. Therefore, the EPA conducted searches for the Oil and Natural Gas Sector: Emission Standards for New and Modified Sources through the Enhanced National Standards Systems Network (NSSN) Database managed by the American National Standards Institute (ANSI). Searches were conducted for EPA Methods 1, 1A, 2, 2A, 2C, 2D, 3A, 3B, 3C, 4, 6, 10, 15, 16, 16A, 18, 21, 22, and 25A of 40 CFR part 60 Appendix A. No applicable voluntary consensus standards were identified for EPA Methods 1A, 2A, 2D, 21, and 22 and none were brought to its attention in comments. All potential standards were reviewed to determine the practicality of the voluntary consensus standards (VCS) for this rule.

Two VCS were identified as an acceptable alternative to EPA test methods for the purpose of this rule. First, ANSI/ASME PTC 19–10–1981, Flue and Exhaust Gas Analyses (Part 10) was identified to be used in lieu of EPA Methods 3B, 6, 6A, 6B, 15A and 16A manual portions only and not the instrumental portion. This standard includes manual and instructional methods of analysis for carbon dioxide, carbon monoxide, hydrogen sulfide, nitrogen oxides, oxygen, and sulfur dioxide. Second, ASTM D6420–99 (2010), ''Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry'' is an acceptable alternative to EPA Method 18 with the following caveats, only use when the target compounds are all known and the target compounds are all listed in ASTM D6420 as measurable. ASTM D6420 should never be specified as a total VOC Method. (ASTM D6420–99 (2010) is not incorporated by reference in 40 CFR part 60.) The search identified 19 VCS that were potentially applicable for this rule in lieu of EPA reference methods. However, these have been determined to not be practical due to lack of equivalency, documentation, validation of data and other important technical and policy considerations. For additional information, please see the April 6, 2016, memo titled, ''Voluntary Consensus Standard Results for Oil and Natural Gas Sector: Emission Standards for New and Modified Sources'' in the public docket.

In this rule, the EPA is finalizing regulatory text for 40 CFR part 60, subpart OOOOa that includes incorporation by reference in accordance with requirements of 1 CFR 51.5 as discussed below. Ten standards are incorporated by reference.

• ASTM D86–96, Distillation of Petroleum Products (Approved April 10, 1996) covers the distillation of natural gasolines, motor gasolines, aviation gasolines, aviation turbine fuels, special boiling point spirits, naphthas, white spirit, kerosines, gas oils, distillate fuel oils, and similar petroleum products, utilizing either manual or automated equipment.

• ASTM D1945–03 (Reapproved 2010), Standard Test Method for Analysis of Natural Gas by Gas Chromatography covers the determination of the chemical composition of natural gases and similar gaseous mixtures within a certain range of composition. This test method may be abbreviated for the analysis of lean natural gases containing negligible amounts of hexanes and higher hydrocarbons, or for the determination of one or more components.

• ASTM D3588–98 (Reapproved 2003), Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuel covers procedures for calculating heating value, relative density, and compressibility factor at base conditions for natural gas mixtures from compositional analysis. It applies to all common types of utility gaseous fuels.

• ASTM D4891–89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion covers the determination of the heating value of natural gases and similar gaseous mixtures within a certain range of composition.

• ASTM D6522–00 (Reapproved December 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers covers the determination of nitrogen oxides, carbon monoxide, and oxygen concentrations in controlled and uncontrolled emissions from natural gas-fired reciprocating engines, combustion turbines, boilers, and process heaters.

• ASTM E168–92, General Techniques of Infrared Quantitative Analysis covers the techniques most often used in infrared quantitative analysis. Practices associated with the collection and analysis of data on a computer are included as well as practices that do not use a computer.

• ASTM E169–93, General Techniques of Ultraviolet Quantitative Analysis (Approved May 15, 1993) provide general information on the techniques most often used in ultraviolet and visible quantitative analysis. The purpose is to render unnecessary the repetition of these descriptions of techniques in individual methods for quantitative analysis.

• ASTM E260–96, General Gas Chromatography Procedures (Approved April 10, 1996) is a general guide to the application of gas chromatography with packed columns for the separation and analysis of vaporizable or gaseous organic and inorganic mixtures and as a reference for the writing and reporting of gas chromatography methods.

• ASME/ANSI PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus] (Issued August 31, 1981) covers measuring the oxygen or carbon dioxide content of the exhaust gas.

• EPA–600/R–12/531, EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (Issued May 2012) is mandatory for certifying the calibration gases being used for the calibration and audit of ambient air quality analyzers and continuous emission monitors that are required by numerous parts of the CFR.

The EPA determined that the ASTM and ASME/ANSI standards, notwithstanding the age of the standards, are reasonably available because it they are available for purchase from the following addresses: American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959; or ProQuest, 300 North Zeeb Road, Ann Arbor, MI 48106 and the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990. The EPA determined that the EPA standard is reasonably available because it is publically available through the EPA's Web site: *http://nepis.epa.gov/Adobe/PDF/P100EKJR.pdf*.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes the human health or environmental risk addressed by this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income, or indigenous populations. The EPA has determined this because the rulemaking increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority, low-income, or indigenous populations. The EPA has provided meaningful participation opportunities for minority, low-income, indigenous populations and tribes during the rulemaking process by conducting community calls and webinars. Documentation of these activities can be found in the public docket for this rulemaking.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping.

Dated: May 12, 2016.

Gina McCarthy,

Administrator.

For the reasons set out in the preamble, title 40, chapter I of the Code of Federal Regulations is amended as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 4701, et seq.

■ 2. Section 60.17 is amended by:

■ a. Revising paragraph (g)(14).

■ b. Revising paragraphs (h)(19), (75), (137), (167), (184), (193), (196), and (199).

■ c. Adding paragraph (j)(2).

The revisions and addition read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(g) * * *

(14) ASME/ANSI PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], (Issued August 31, 1981), IBR approved for §§ 60.56c(b), 60.63(f), 60.106(e), 60.104a(d), (h), (i), and (j), 60.105a(d), (f), and (g), § 60.106a(a), § 60.107a(a), (c), and (d), tables 1 and 3 to subpart EEEE, tables 2 and 4 to subpart FFFF, table 2 to subpart JJJJ, § 60.285a(f), §§ 60.4415(a), 60.2145(s) and (t), 60.2710(s), (t), and (w), 60.2730(q), 60.4900(b), 60.5220(b), tables 1 and 2 to subpart LLLL, tables 2 and 3 to subpart MMMM, 60.5406(c), 60.5406a(c), 60.5407a(g), 60.5413(b), 60.5413a(b) and 60.5413a(d).

* * * * *

(h) * * *

(19) ASTM D86–96, Distillation of Petroleum Products, (Approved April 10, 1996), IBR approved for §§ 60.562–2(d), 60.593(d), 60.593a(d), 60.633(h), 60.5401(f), 60.5401a(f).

* * * * *

(75) ASTM D1945–03 (Reapproved 2010), Standard Method for Analysis of Natural Gas by Gas Chromatography, (Approved January 1, 2010), IBR approved for §§ 60.107a(d), 60.5413(d), 60.5413a(d).

* * * * *

(137) ASTM D3588–98 (Reapproved 2003), Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, (Approved May 10, 2003), IBR approved for §§ 60.107a(d), 60.5413(d), and 60.5413a(d).

* * * * *

(167) ASTM D4891–89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, (Approved June 1, 2006), IBR approved for §§ 60.107a(d), 60.5413(d), and 60.5413a(d).

* * * * *

(184) ASTM D6522–00 (Reapproved 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, (Approved October 1, 2005), IBR approved for table 2 to subpart JJJJ, §§ 60.5413(b) and (d), and 60.5413a(b).

* * * * *

(193) ASTM E168–92, General Techniques of Infrared Quantitative Analysis, IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), 60.632(f), 60.5400, 60.5400a(f).

* * * * *

(196) ASTM E169–93, General Techniques of Ultraviolet Quantitative Analysis, (Approved May 15, 1993), IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), 60.632(f), 60.5400(f), and 60.5400a(f).

* * * * *

(199) ASTM E260–96, General Gas Chromatography Procedures, (Approved April 10, 1996), IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), 60.632(f), 60.5400(f), 60.5400a(f) 60.5406(b), and 60.5406a(b)(3).

* * * * *

(j) * * *

(2) EPA–600/R–12/531, EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards, May 2012, IBR approved for §§ 60.5413(d) and 60.5413a(d).

* * * * *

■ 3. Part 60 is amended by revising the heading for Subpart OOOO to read as follows:

Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution for which Construction, Modification or Reconstruction Commenced after August 23, 2011, and on or before September 18, 2015

■ 4. Section 60.5360 is revised to read as follows:

§ 60.5360 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from affected facilities that commence construction, modification or reconstruction after August 23, 2011, and on or before September 18, 2015.

■ 5. Section 60.5365 is amended by:
■ a. Revising the introductory text.
■ b. Revising paragraph (e)(4).
■ c. Adding paragraph (e)(5).
■ d. Revising paragraph (h)(4).

The revisions and addition read as follows:

§ 60.5365 Am I subject to this subpart?

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (g) of this section for which you commence construction, modification or reconstruction after August 23, 2011, and on or before September 18, 2015.

* * * * *

(e) * * *

(4) The following requirements apply immediately upon startup, startup of production, or return to service. A storage vessel affected facility that is reconnected to the original source of liquids is a storage vessel affected facility subject to the same requirements that applied before being removed from service. Any storage vessel that is used to replace any storage vessel affected facility is subject to the same requirements that apply to the storage vessel affected facility being replaced.

(5) 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 affected facility.

(h) * * *

(4) A gas well facility initially constructed after August 23, 2011, and on or before September 18, 2015 is considered an affected facility regardless of this provision.

■ 6. Section 60.5370 is amended by revising paragraph (b) and adding paragraph (d) to read as follows:

§ 60.5370 When must I comply with this subpart?

* * * * *

(b) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

* * * * *

(d) You are deemed to be in compliance with this subpart if you are in compliance with all applicable provisions of subpart OOOOa of this part.

§ 60.5410 [Amended]

■ 7. Section 60.5410 is amended by removing and reserving paragraph (b)(6).

■ 8. Section 60.5411 is amended by revising paragraphs (a)(3)(i)(A) and (c)(3)(i)(A) to read as follows:

§ 60.5411 What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing materials from storage vessels and centrifugal compressor wet seal degassing systems?

* * * * *

(a) * * *

(3) * * *

(i) * * *

(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 § 60.5416(a)(4) 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. You must maintain records of each time the alarm is activated according to § 60.5420(c)(8).

* * * * *

(c) * * *

(3) * * *

(i) * * *

(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 and that 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. You must maintain records of each time the alarm is activated according to § 60.5420(c)(8).

* * * * *

■ 9. Section 60.5412 is amended by:

■ a. Revising paragraphs (a)(1)(ii) and (d)(1) introductory text; and

■ b. Adding paragraph (d)(1)(iv).

The revisions and addition read as follows:

§ 60.5412 What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my storage vessel or centrifugal compressor affected facility?

* * * * *

(a) * * *

(1) * * *

(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 requirements of § 60.5413.

* * * * *

(d) * * *

(1) Each enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed to reduce the mass content of VOC emissions by 95.0 percent or greater. Each flare must be designed and operated in accordance with the requirements of § 60.5413(a)(1). You must follow the requirements in paragraphs (d)(1)(i) through (iv) of this section.

* * * * *

(iv) 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 (d)(1)(iv)(A) through (D) of this section.

(A) 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 § 60.5413.

(B) 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 requirements of § 60.5413.

(C) You must operate at a minimum temperature of 760 °Celsius, provided the control device has demonstrated, during the performance test conducted under § 60.5413, that combustion zone temperature is an indicator of destruction efficiency.

(D) 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.

* * * * *

■ 10. Section 60.5413 is amended by revising paragraphs (d)(9)(iv) and (e)(3) to read as follows:

§ 60.5413 What are the performance testing procedures for control devices used to demonstrate compliance at my storage vessel or centrifugal compressor affected facility?

* * * * *

(d) * * *

(9) * * *

(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,'' (incorporated by reference as specified in § 60.17).

* * * * *

(e) * * *

(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, 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.

* * * * *

■ 11. Section 60.5415 is amended by revising paragraphs (b)(2)(vii)(B) and (c)(4) to read as follows:

§ 60.5415 How do I demonstrate continuous compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?

* * * * *

(b) * * *

(2) * * *

(vii) * * *

(B) 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 Method 22, 40 CFR part 60, appendix A, 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) * * *

(4) You must operate the rod packing emissions collection system under negative pressure and continuously comply with the closed vent requirements in § 60.5416(a) and (b).

* * * * *

■ 12. Section 60.5416 is amended by revising paragraph (c)(3)(i) to read as follows:

§ 60.5416 What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my storage vessel and centrifugal compressor affected facilities?

* * * * *

(c) * * *

(3) * * *

(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 activated according to § 60.5420(c)(8).

* * * * *

■ 13. Section 60.5420 is amended by:

■ a. Revising paragraph (c) introductory text; and

■ b. Revising paragraph (c)(6); and

■ c. Adding paragraph (c)(14).

The revision and addition reads as follows:

§ 60.5420 What are my notification, reporting, and recordkeeping requirements?

* * * * *

(c) *Recordkeeping requirements.* You must maintain the records identified as specified in § 60.7(f) and in paragraphs (c)(1) through (14) of this section. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years.

* * * * *

(6) Records of each closed vent system inspection required under

§ 60.5416(a)(1) and (2) for centrifugal or reciprocating compressors or § 60.5416(c)(1) for storage vessels.

* * * * *

(14) A log of records as specified in §§ 60.5412(d)(1)(iii) and 60.5413(e)(4) for all inspection, repair and maintenance activities for each control device failing the visible emissions test.

■ 14. Section 60.5430 is amended by:

■ a. Adding, in alphabetical order, a definition for the term ''capital expenditure;'' and

■ b. Revising the definition for ''group 2 storage vessel.''

■ The addition and revision read as follows:

§ 60.5430 What definitions apply to this subpart?

* * * * *

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(1) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where

(i) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation: $A = Y \times (B \div 100)$;

(ii) The percent Y is determined from the following equation: $Y = 1.0 - 0.575 \log X$, where X is 2011 minus the year of construction; and

(iii) The applicable basic annual asset guideline repair allowance, B, is 4.5.

(2) [Reserved]

* * * * *

Group 2 storage vessel means a storage vessel, as defined in this section, for which construction, modification or reconstruction has commenced after April 12, 2013, and on or before September 18, 2015.

* * * * *

■ 15. Amend Table 3 to Subpart OOOO by revising entries ''§ 60.15'' and ''§ 60.18'' to read as follows:

TABLE 3 TO SUBPART OOOO OF PART 60—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART OOOO

General provisions citation	Subject of citation	Applies to subpart?	Explanation
* * * * * * *			
§ 60.15	Reconstruction	Yes	Except that § 60.15(d) does not apply to gas wells, pneumatic controllers, centrifugal compressors, reciprocating compressors or storage vessels.
* * * * * * *			
§ 60.18	General control device requirements.	Yes	Except that the period of visible emissions shall not exceed a total of 1 minute during any 15-minute period instead of 5 minutes during any 2 consecutive hours as required in § 60.18(c).
* * * * * * *			

■ 16. Add subpart OOOOa, consisting of sections 60.5360a through 60.5499a, to part 60 to read as follows:

Subpart OOOOa—Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after September 18, 2015

Sec.

Subpart OOOOa—Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015

§ 60.5360a What is the purpose of this subpart?

(a) This subpart establishes emission standards and compliance schedules for the control of the pollutant greenhouse gases (GHG). The greenhouse gas standard in this subpart is in the form of a limitation on emissions of methane from affected facilities in the crude oil and natural gas source category that commence construction, modification, or reconstruction after September 18, 2015. This subpart also establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from affected facilities in the crude oil and natural gas source category that commence construction, modification or reconstruction after September 18, 2015. The effective date of the rule is August 2, 2016.

(b) *Prevention of Significant Deterioration (PSD) and title V thresholds for Greenhouse Gases.* (1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any State Implementation Plan (SIP) approved by the EPA that is interpreted to incorporate, or specifically incorporates, § 51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Clean Air Act as defined in 40 CFR 52.21(b)(49).

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in 40 CFR 71.2.

§ 60.5365a Am I subject to this subpart?

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (j) of this section for which you commence construction, modification, or reconstruction after September 18, 2015.

(a) Each well affected facility, which is a single well that conducts a well completion operation following hydraulic fracturing or refracturing. The provisions of this paragraph do not affect the affected facility status of well sites for the purposes of § 60.5397a. The provisions of paragraphs (a)(1) through (4) of this section apply to wells that are hydraulically refractured: (1) A well that conducts a well completion operation following hydraulic refracturing is not an affected facility, provided that the requirements of § 60.5375a(a)(1) through (4) are met. However, hydraulic refracturing of a well constitutes a modification of the well site for purposes of paragraph (i)(3)(iii) of this section, regardless of affected facility status of the well itself.

(2) A well completion operation following hydraulic refracturing not conducted pursuant to § 60.5375a(a)(1) through (4) is a modification to the well.

(3) Except as provided in § 60.5365a(i)(3)(iii), refracturing of a well, by itself, does not affect the modification status of other equipment, process units, storage vessels, compressors, pneumatic pumps, or pneumatic controllers.

(4) A well initially constructed after September 18, 2015, that conducts a well completion operation following hydraulic refracturing is considered an affected facility regardless of this provision.

(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(d) Each pneumatic controller affected facility:

(1) Each pneumatic controller affected facility not located at a natural gas processing plant, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 scfh.

(2) Each pneumatic controller affected facility located at a natural gas processing plant, which is a single continuous bleed natural gas-driven pneumatic controller.

(e) Each storage vessel affected facility, which is a single storage vessel with the potential for VOC emissions equal to or greater than 6 tpy as determined according to this section. 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 specified in this subsection. 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.

(1) For each new, modified or reconstructed storage vessel you must determine the potential for VOC emissions within 30 days after liquids first enter the storage vessel, except as provided in paragraph (e)(3)(iv) of this section. For each new, modified or reconstructed storage vessel receiving liquids pursuant to the standards for well affected facilities in § 60.5375a, including wells subject to § 60.5375a(f), you must determine the potential for VOC emissions within 30 days after startup of production of the well.

(2) A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than 6 tpy shall remain an affected facility under this subpart.

(3) For storage vessels not subject to a legally and practically enforceable limit in an operating permit or other requirement established under 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 affected facility status, provided you comply with the requirements in paragraphs (e)(3)(i) through (iv) of this section.

(i) You meet the cover requirements specified in § 60.5411a(b).

(ii) You meet the closed vent system requirements specified in § 60.5411a(c) and (d).

(iii) You must maintain records that document compliance with paragraphs (e)(3)(i) and (ii) of this section.

(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 (e)(3)(i) and (ii) 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.

(4) The following requirements apply immediately upon startup, startup of production, or return to service. A storage vessel affected facility that is reconnected to the original source of liquids is a storage vessel affected facility subject to the same requirements that applied before being removed from service. Any storage vessel that is used to replace any storage vessel affected facility is subject to the same requirements that apply to the storage vessel affected facility being replaced.

(5) 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 affected facility.

(f) The group of all equipment within a process unit is an affected facility.

(1) Addition or replacement of equipment for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(2) 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 §§ 60.5400a, 60.5401a, 60.5402a, 60.5421a, and 60.5422a 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 provisions of §§ 60.5400a, 60.5401a, 60.5402a, 60.5421a, and 60.5422a.

(3) The equipment within a process unit of an affected facility located at onshore natural gas processing plants and described in paragraph (f) of this section are exempt from this subpart if they are subject to and controlled according to subparts VVa, GGG, or GGGa of this part.

(g) Sweetening units located at onshore natural gas processing plants that process natural gas produced from either onshore or offshore wells.

(1) Each sweetening unit that processes natural gas is an affected facility; and

(2) Each sweetening unit that processes natural gas followed by a sulfur recovery unit is an affected facility.

(3) Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H_2S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in § 60.5423a(c) but are not required to comply with §§ 60.5405a through 60.5407a and §§ 60.5410a(g) and 60.5415a(g).

(4) Sweetening facilities producing acid gas that is completely re-injected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere are not subject to §§ 60.5405a through 60.5407a, 60.5410a(g), 60.5415a(g), and 60.5423a.

(h) Each pneumatic pump affected facility:

(1) For natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven diaphragm pump.

(2) For well sites, each pneumatic pump affected facility, which is a single natural gas-driven diaphragm pump. A single natural gas-driven diaphragm pump that is in operation less than 90 days per calendar year is not an affected facility under this subpart provided the owner/operator keeps records of the days of operation each calendar year and submits such records to the EPA Administrator (or delegated enforcement authority) upon request. For the purposes of this section, any period of operation during a calendar day counts toward the 90 calendar day threshold.

(i) Except as provided in § 60.5365a(i)(2), the collection of fugitive emissions components at a well site, as defined in § 60.5430a, is an affected facility.

(1) [Reserved]

(2) A well site that only contains one or more wellheads is not an affected facility under this subpart. The affected facility status of a separate tank battery surface site has no effect on the affected facility status of a well site that only contains one or more wellheads.

(3) For purposes of § 60.5397a, a "modification" to a well site occurs when:

(i) A new well is drilled at an existing well site;

(ii) A well at an existing well site is hydraulically fractured; or

(iii) A well at an existing well site is hydraulically refractured.

(j) The collection of fugitive emissions components at a compressor station, as defined in § 60.5430a, is an affected facility. For purposes of § 60.5397a, a "modification" to a compressor station occurs when:

(1) An additional compressor is installed at a compressor station; or

(2) One or more compressors at a compressor station is replaced by one or more compressors of greater total horsepower than the compressor(s) being replaced. When one or more compressors is replaced by one or more compressors of an equal or smaller total horsepower than the compressor(s) being replaced, installation of the replacement compressor(s) does not trigger a modification of the compressor station for purposes of § 60.5397a.

§ 60.5370a When must I comply with this subpart?

(a) You must be in compliance with the standards of this subpart no later than August 2, 2016 or upon startup, whichever is later.

(b) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. The provisions for exemption from compliance during periods of startup, shutdown and malfunctions provided for in 40 CFR 60.8(c) do not apply to this subpart.

(c) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

§ 60.5375a What GHG and VOC standards apply to well affected facilities?

If you are the owner or operator of a well affected facility as described in § 60.5365a(a) that also meets the criteria for a well affected facility in § 60.5365(a) of subpart OOOO of this part, you must reduce GHG (in the form of a limitation on emissions of methane) and VOC emissions by complying with paragraphs (a) through (g) of this section. If you own or operate a well affected facility as described in § 60.5365a(a) that does not meet the criteria for a well affected facility in § 60.5365(a) of subpart OOOO of this part, you must reduce GHG and VOC emissions by complying with paragraphs (f)(3), (f)(4) or (g) for each well completion operation with hydraulic fracturing prior to November 30, 2016, and you must comply with paragraphs (a) through (g) of this section for each well completion operation with hydraulic fracturing on or after November 30, 2016.

(a) Except as provided in paragraph (f) and (g) of this section, for each well completion operation with hydraulic fracturing you must comply with the requirements in paragraphs (a)(1) through (4) of this section. You must maintain a log as specified in paragraph (b) of this section.

(1) For each stage of the well completion operation, as defined in § 60.5430a, follow the requirements specified in paragraphs (a)(1)(i) through (iii) of this section.

(i) During the initial flowback stage, route the flowback into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the initial flowback stage is not subject to control under this section.

(ii) During the separation flowback stage, route all recovered liquids from the separator to one or more well completion vessels or storage vessels, re-inject the recovered liquids into the well or another well, or route the recovered liquids to a collection system. Route the recovered gas from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an onsite fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. If it is technically infeasible to route the recovered gas as required above, follow the requirements in paragraph (a)(3) of this section. If, at any time during the separation flowback stage, it is technically infeasible for a separator to function, you must comply with paragraph (a)(1)(i) of this section.

(iii) You must have a separator onsite during the entirety of the flowback period, except as provided in paragraphs (a)(1)(iii)(A) through (C) of this section.

(A) A well that is not hydraulically fractured or refractured with liquids, or that does not generate condensate, intermediate hydrocarbon liquids, or produced water such that there is no liquid collection system at the well site is not required to have a separator onsite.

(B) If conditions allow for liquid collection, then the operator must immediately stop the well completion operation, install a separator, and restart the well completion operation in accordance with § 60.5375a(a)(1).

(C) The owner or operator of a well that meets the criteria of paragraph (a)(1)(iii)(A) or (B) of this section must submit the report in § 60.5420a(b)(2) and maintain the records in § 60.5420a(c)(1)(iii).

(2) [Reserved]

(3) If it is technically infeasible to route the recovered gas as required in § 60.5375a(a)(1)(ii), then you must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

(4) You have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.

(b) You must maintain a log for each well completion operation at each well affected facility. The log must be completed on a daily basis for the duration of the well completion operation and must contain the records specified in § 60.5420a(c)(1)(iii).

(c) You must demonstrate initial compliance with the standards that apply to well affected facilities as required by § 60.5410a(a).

(d) You must demonstrate continuous compliance with the standards that apply to well affected facilities as required by § 60.5415a(a).

(e) You must perform the required notification, recordkeeping and reporting as required by § 60.5420a(a)(2), (b)(1) and (2), and (c)(1).

(f) For each well affected facility specified in paragraphs (f)(1) and (2) of this section, you must comply with the requirements of paragraphs (f)(3) and (4) of this section.

(1) Each well completion operation with hydraulic fracturing at a wildcat or delineation well.

(2) Each well completion operation with hydraulic fracturing at a non-wildcat low pressure well or non-delineation low pressure well.

(3) You must comply with either paragraph (f)(3)(i) or (f)(3)(ii) of this section, unless you meet the requirements in paragraph (g) of this section. You must also comply with paragraph (b) of this section.

(i) Route all flowback to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

(ii) Route all flowback into one or more well completion vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the flowback before the separator can function is not subject to control under this section. Capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame. (4) You must submit the notification as specified in § 60.5420a(a)(2), submit annual reports as specified in § 60.5420a(b)(1) and (2) and maintain records specified in § 60.5420a(c)(1)(iii) for each wildcat and delineation well. You must submit the notification as specified in § 60.5420a(a)(2), submit annual reports as specified in § 60.5420a(b)(1) and (2), and maintain records as specified in § 60.5420a(c)(1)(iii) and (vii) for each low pressure well.

(g) For each well affected facility with less than 300 scf of gas per stock tank barrel of oil produced, you must comply with paragraphs (g)(1) and (2) of this section.

(1) You must maintain records specified in § 60.5420a(c)(1)(vi).

(2) You must submit reports specified in § 60.5420a(b)(1) and (2).

§ 60.5380a What GHG and VOC standards apply to centrifugal compressor affected facilities?

You must comply with the GHG and VOC standards in paragraphs (a) through (d) of this section for each centrifugal compressor affected facility.

(a)(1) You must reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent.

(2) 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 § 60.5411a(b). The cover must be connected through a closed vent system that meets the requirements of § 60.5411a(a) and (d) and the closed vent system must be routed to a control device that meets the conditions specified in § 60.5412a(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(b) You must demonstrate initial compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5410a(b).

(c) You must demonstrate continuous compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5415a(b).

(d) You must perform the reporting as required by § 60.5420a(b)(1) and (3), and the recordkeeping as required by § 60.5420a(c)(2), (6) through (11), and (17), as applicable.

§ 60.5385a What GHG and VOC standards apply to reciprocating compressor affected facilities?

You must reduce GHG (in the form of a limitation on emissions of methane) and VOC emissions by complying with the standards in paragraphs (a) through (d) of this section for each reciprocating compressor affected facility.

(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 upon initial startup of your reciprocating compressor affected facility, 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 date of startup for a new reciprocating compressor for which the rod packing has not yet been replaced.

(3) Collect the methane and VOC emissions from the rod packing using a rod packing emissions collection system that operates under negative pressure and route the rod packing emissions to a process through a closed vent system that meets the requirements of § 60.5411a(a) and (d).

(b) You must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5410a(c).

(c) You must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5415a(c).

(d) You must perform the reporting as required by § 60.5420a(b)(1) and (4) and the recordkeeping as required by § 60.5420a(c)(3), (6) through (9), and (17), as applicable.

§ 60.5390a What GHG and VOC standards apply to pneumatic controller affected facilities?

For each pneumatic controller affected facility you must comply with the GHG and VOC standards, based on natural gas as a surrogate for GHG and VOC, 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 this requirement.

(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 affected facility 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 month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller, as required in § 60.5420a(c)(4)(ii).

(b)(1) Each pneumatic controller affected facility at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller as required in § 60.5420a(c)(4)(iv).

(c)(1) Each pneumatic controller affected facility at a location other than at a natural gas processing plant must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller affected facility at a location other than at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that controller as required in § 60.5420a(c)(4)(iii).

(d) You must demonstrate initial compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5410a(d).

(e) You must demonstrate continuous compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5415a(d).

(f) You must perform the reporting as required by § 60.5420a(b)(1) and (5) and the recordkeeping as required by § 60.5420a(c)(4).

§ 60.5393a What GHG and VOC standards apply to pneumatic pump affected facilities?

For each pneumatic pump affected facility you must comply with the GHG and VOC standards, based on natural gas as a surrogate for GHG and VOC, in either paragraph (a) or (b) of this section, as applicable, on or after November 30, 2016.

(a) Each pneumatic pump affected facility at a natural gas processing plant must have a natural gas emission rate of zero.

(b) For each pneumatic pump affected facility at a well site you must comply with paragraph (b)(1) or (2) of this section.

(1) If the pneumatic pump affected facility is located at a greenfield site as

defined in § 60.5430a, you must reduce natural gas emissions by 95.0 percent, except as provided in paragraphs (b)(3) and (4) of this section.

(2) If the pneumatic pump affected facility is not located at a greenfield site as defined in § 60.5430a, you must reduce natural gas emissions by 95.0 percent, except as provided in paragraphs (b)(3), (4) and (5) of this section.

(3) 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) or (b)(2) of this section. If you do not have a control device installed on site by the compliance date and you do not have the ability to route to a process, then you must comply instead with the provisions of paragraphs (b)(3)(i) and (ii) of this section.

(i) Submit a certification in accordance with § 60.5420a(b)(8)(i)(A) in your next annual report, certifying that there is no available control device or process on site and maintain the records in § 60.5420a(c)(16)(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 comply with paragraph (b)(2)(i) of this section and must submit the information in § 60.5420a(b)(8)(ii) in your next annual report and maintain the records in § 60.5420a(c)(16)(i), (ii), and (iii). You must be in compliance with the requirements of paragraph (b)(2) of this section within 30 days of startup of the control device or within 30 days of the ability to route to a process.

(4) If the control device available on site is unable to achieve a 95 percent reduction and there is no ability to route the emissions to a process, you must still route the pneumatic pump affected facility's emissions to that existing control device. If you route the pneumatic pump affected facility to a control device installed on site that is designed to achieve less than a 95 percent reduction, you must submit the information specified in § 60.5420a(b)(8)(i)(C) in your next annual report and maintain the records in § 60.5420a(c)(16)(iii).

(5) If an owner or operator at a non-greenfield site determines, 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)(5)(i) through (iv) of this section must be met.

(i) The owner or operator shall conduct the assessment of technical infeasibility in accordance with the criteria in paragraph (b)(5)(iii) of this section and have it certified by a qualified professional engineer in accordance with paragraph (b)(5)(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 § 60.5393a(b)(5)(iii). 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 onsite or to a process shall 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. The assessment of technical infeasibility shall be prepared 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) The owner or operator shall maintain the records § 60.5420a(c)(16)(iv).

(6) 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) or (b)(2) of this section, and instead must comply with paragraph (b)(3) of this section and report the change in next annual report in accordance with § 60.5420a(b)(8)(ii).

(c) If you use a control device or route to a process to reduce emissions, you must connect the pneumatic pump affected facility through a closed vent system that meets the requirements of § 60.5411a(a) and (d).

(d) You must demonstrate initial compliance with standards that apply to pneumatic pump affected facilities as required by § 60.5410a(e).

(e) You must perform the reporting as required by § 60.5420a(b)(1) and (8) and the recordkeeping as required by § 60.5420a(c)(6) through (10), (16), and (17), as applicable.

§ 60.5395a What VOC standards apply to storage vessel affected facilities?

Except as provided in paragraph (e) of this section, you must comply with the VOC standards in this section for each storage vessel affected facility.

(a) You must comply with the requirements of paragraphs (a)(1) and (2) of this section. After 12 consecutive months of compliance with paragraph (a)(2) of this section, you may continue to comply with paragraph (a)(2) of this section, or you may comply with paragraph (a)(3) of this section, if applicable. If you choose to meet the requirements in paragraph (a)(3) of this section, you are not required to comply with the requirements of paragraph (a)(2) of this section except as provided in paragraphs (a)(3)(i) and (ii) of this section.

(1) Determine the potential for VOC emissions in accordance with § 60.5365a(e).

(2) Reduce VOC emissions by 95.0 percent within 60 days after startup. For storage vessel affected facilities receiving liquids pursuant to the standards for well affected facilities in § 60.5375a(a)(1)(i) or (ii), you must achieve the required emissions reductions within 60 days after startup of production as defined in § 60.5430a.

(3) Maintain the uncontrolled actual VOC emissions from the storage vessel affected facility 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, and the calculations must be based on the average throughput for the month. You may no longer comply with this paragraph and must instead comply with paragraph (a)(2) of this section if your storage vessel affected facility meets the conditions specified in paragraphs (a)(3)(i) or (ii) of this section.

(i) If a well feeding the storage vessel affected facility undergoes fracturing or refracturing, you must comply with paragraph (a)(2) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel affected facility.

(ii) If the monthly emissions determination required in this section indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility, you must comply with paragraph (a)(2) of this section within 30 days of the monthly determination.

(b) *Control requirements.* (1) Except as required in paragraph (b)(2) of this section, if you use a control device to reduce VOC emissions from your storage vessel affected facility, you must equip the storage vessel with a cover that meets the requirements of § 60.5411a(b) and is connected through a closed vent system that meets the requirements of § 60.5411a(c) and (d), and you must route emissions to a control device that meets the conditions specified in § 60.5412a(c) or (d). 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 § 60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb.

(c) Requirements for storage vessel affected facilities that are removed from service or returned to service. If you remove a storage vessel affected facility from service, you must comply with paragraphs (c)(1) through (3) of this section. A storage vessel is not an affected facility under this subpart for the period that it is removed from service.

(1) For a storage vessel affected facility to be removed from service, you must comply with the requirements of paragraphs (c)(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 as required in § 60.5420a(b)(6)(v) in your next annual report, identifying each storage vessel affected facility removed from service during the reporting period and the date of its removal from service.

(2) If a storage vessel identified in paragraph (c)(1)(ii) of this section is returned to service, you must determine its affected facility status as provided in § 60.5365a(e).

(3) For each storage vessel affected facility returned to service during the reporting period, you must submit a notification in your next annual report as required in § 60.5420a(b)(6)(vi), identifying each storage vessel affected facility and the date of its return to service.

(d) Compliance, notification, recordkeeping, and reporting. You must comply with paragraphs (d)(1) through (3) of this section.

(1) You must demonstrate initial compliance with standards as required by § 60.5410a(h) and (i).

(2) You must demonstrate continuous compliance with standards as required by § 60.5415a(e)(3).

(3) You must perform the required reporting as required by § 60.5420a(b)(1) and (6) and the recordkeeping as required by § 60.5420a(c)(5) through (8), (12) through (14), and (17), as applicable.

(e) *Exemptions.* This subpart does not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, and 40 CFR part 63, subparts G, CC, HH, or WW.

§ 60.5397a What fugitive emissions GHG and VOC standards apply to the affected facility which is the collection of fugitive emissions components at a well site and the affected facility which is the collection of fugitive emissions components at a compressor station?

For each affected facility under § 60.5365a(i) and (j), you must reduce GHG (in the form of a limitation on emissions of methane) and VOC emissions by complying with the requirements of paragraphs (a) through (j) of this section. These requirements are independent of the closed vent system and cover requirements in § 60.5411a.

(a) You must monitor all fugitive emission components, as defined in § 60.5430a, in accordance with paragraphs (b) through (g) of this section. You must repair all sources of fugitive emissions in accordance with paragraph (h) of this section. You must keep records in accordance with paragraph (i) of this section and report in accordance with paragraph (j) of this section. For purposes of this section, fugitive emissions are defined as: Any visible emission from a fugitive emissions component observed using optical gas imaging or an instrument reading of 500 ppm or greater using Method 21.

(b) You must develop an emissions monitoring plan that covers the collection of fugitive emissions components at well sites and compressor 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 (8) of this section, at a minimum.

(1) Frequency for conducting surveys. Surveys must be conducted at least as frequently as required by paragraphs (f) and (g) of this section.

(2) Technique for determining fugitive emissions (*i.e.,* Method 21 at 40 CFR part 60, appendix A–7, or optical gas imaging).

(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. Your repair schedule must meet the requirements of paragraph (h) 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 either be performed by the facility, by the manufacturer, or by a third party. For the purposes of complying with the fugitives 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 ≤60g/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 Method 21 of appendix A–7 of this part, 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 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 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 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 (4) of this section, at a minimum, as applicable.

(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, your plan must also include a list of fugitive emissions components to be monitored and 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 paragraph (g)(3)(i) of this section, and the written plan for fugitive emission components designated as unsafe-to-monitor in accordance with paragraph (g)(3)(ii) of this section.

(e) Each monitoring survey shall observe each fugitive emissions component, as defined in § 60.5430a, for fugitive emissions.

(f)(1) You must conduct an initial monitoring survey within 60 days of the startup of production, as defined in § 60.5430a, for each collection of fugitive emissions components at a new well site or by June 3, 2017, whichever is later. For a modified collection of fugitive emissions components at a well site, the initial monitoring survey must be conducted within 60 days of the first day of production for each collection of fugitive emission components after the modification or by June 3, 2017, whichever is later.

(2) You must conduct an initial monitoring survey within 60 days of the startup of a new compressor station for each new collection of fugitive emissions components at the new compressor station or by June 3, 2017, whichever is later. For a modified collection of fugitive components at a compressor station, the initial monitoring survey must be conducted within 60 days of the modification or by June 3, 2017, whichever is later.

(g) A monitoring survey of each collection of fugitive emissions components at a well site or at a compressor station must be performed at the frequencies specified in paragraphs (g)(1) and (2) of this section, with the exceptions noted in paragraphs (g)(3) and (4) 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 compressor 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 (g)(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 paragraphs (b), (c), and (d) of this section.

(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 (g)(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 paragraphs (b), (c), and (d) of this section.

(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 (g)(2) of this section are waived for any collection of fugitive emissions components at a compressor 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 (g)(2) of this section shall not be waived for two consecutive quarterly monitoring periods.

(h) Each identified source of fugitive emissions shall be repaired or replaced in accordance with paragraphs (h)(1) and (2) of this section. For fugitive emissions components also subject to the repair provisions of §§ 60.5416a(b)(9) through (12) and (c)(4) through (7), those provisions apply instead to those closed vent system and covers, and the repair provisions of paragraphs (h)(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 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.

(3) Each repaired or replaced fugitive emissions component must be resurveyed as soon as practicable, but no later than 30 days after being repaired, 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 either Method 21 or optical gas imaging within 30 days of finding such fugitive emissions.

(ii) For each repair 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 Method 21 to resurvey the repaired fugitive emissions components are subject to the resurvey provisions specified in paragraphs (h)(3)(iii)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the 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 Method 21 are used.

(B) Operators must use the 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 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 (h)(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.

(i) Records for each monitoring survey shall be maintained as specified § 60.5420a(c)(15).

(j) Annual reports shall be submitted for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station that include the information specified in § 60.5420a(b)(7). Multiple collection of fugitive emissions components at a well site or at a compressor station may be included in a single annual report.

§ 60.5398a What are the alternative means of emission limitations for GHG and VOC from well completions, reciprocating compressors, the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in GHG (in the form of a limitation on emission of methane) and VOC emissions at least equivalent to the reduction in GHG and VOC emissions achieved under § 60.5375a, § 60.5385a, and § 60.5397a, the Administrator will publish, in the **Federal Register**, a notice permitting the use of that alternative means for the purpose of compliance with § 60.5375a, § 60.5385a, and § 60.5397a. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities.

(d) Determination of equivalence to the design, equipment, work practice or operational requirements of this section will be evaluated by the following guidelines:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months to demonstrate the equivalence of the alternative means of emission limitation. The application must include the following information:

(i) A description of the technology or process.

(ii) The monitoring instrument and measurement technology or process.

(iii) A description of performance based procedures (*i.e.,* method) and data quality indicators for precision and bias; the method detection limit of the technology or process.

(iv) For affected facilities under § 60.5397a, the action criteria and level at which a fugitive emission exists.

(v) Any initial and ongoing quality assurance/quality control measures.

(vi) Timeframes for conducting ongoing quality assurance/quality control.

(vii) Field data verifying viability and detection capabilities of the technology or process.

(viii) Frequency of measurements.

(ix) Minimum data availability.

(x) Any restrictions for using the technology or process.

(xi) Operation and maintenance procedures and other provisions necessary to ensure reduction in methane and VOC emissions at least equivalent to the reduction in methane and VOC emissions achieved under § 60.5397a.

(xii) Initial and continuous compliance procedures, including recordkeeping and reporting.

(2) For each determination of equivalency requested, the emission reduction achieved by the design, equipment, work practice or operational requirements shall be demonstrated.

(3) For each affected facility for which a determination of equivalency is requested, the emission reduction achieved by the alternative means of emission limitation shall be demonstrated.

(4) Each owner or operator applying for a determination of equivalence to a work practice standard shall commit in writing to work practice(s) that provide for emission reductions equal to or

greater than the emission reductions achieved by the required work practice.

(e) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the **Federal Register**.

(f) An application submitted under this section will be evaluated as set forth in paragraphs (f)(1) and (2) of this section.

(1) The Administrator will compare the demonstrated emission reduction for the alternative means of emission limitation to the demonstrated emission reduction for the design, equipment, work practice or operational requirements and, if applicable, will consider the commitment in paragraph (d) of this section.

(2) The Administrator may condition the approval of the alternative means of emission limitation on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as the design, equipment, work practice or operational requirements. (g) Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design or operational standard within the meaning of section 111(h)(1) of the CAA.

§ 60.5400a What equipment leak GHG and VOC standards apply to affected facilities at an onshore natural gas processing plant?

This section applies to the group of all equipment, except compressors, within a process unit.

(a) You must comply with the requirements of §§ 60.482–1a(a), (b), and (d), 60.482–2a, and 60.482–4a through 60.482–11a, except as provided in § 60.5401a.

(b) You may elect to comply with the requirements of §§ 60.483–1a and 60.483–2a, as an alternative.

(c) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of methane and VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of § 60.5402a.

(d) You must comply with the provisions of § 60.485a except as provided in paragraph (f) of this section.

(e) You must comply with the provisions of §§ 60.486a and 60.487a except as provided in §§ 60.5401a, 60.5421a, and 60.5422a.

(f) You must use the following provision instead of § 60.485a(d)(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 (incorporated by reference as specified in § 60.17) must be used.

§ 60.5401a What are the exceptions to the equipment leak GHG and VOC standards for affected facilities at onshore natural gas processing plants?

(a) You may comply with the following exceptions to the provisions of § 60.5400a(a) and (b).

(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 § 60.485a(b) except as provided in § 60.5400a(c) and in paragraph (b)(4) of this section, and § 60.482–4a(a) through (c) of subpart VVa of this part.

(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 § 60.482–9a.

(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 nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are onsite, instead of within 5 days as specified in paragraph (b)(1) of this section and § 60.482–4a(b)(1).

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section may be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Sampling connection systems are exempt from the requirements of § 60.482–5a.

(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 that are located at a nonfractionating 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 §§ 60.482–2a(a)(1), 60.482–7a(a), 60.482–11a(a), and paragraph (b)(1) of this section.

(e) 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 §§ 60.482–2a(a)(1), 60.482–7a(a), 60.482–11a(a), and paragraph (b)(1) of this section.

(f) An owner or operator may use the following provisions instead of § 60.485a(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °Celsius (302 °Fahrenheit) as determined by ASTM Method D86–96 (incorporated by reference as specified in § 60.17).

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °Celsius (302 °Fahrenheit) as determined by ASTM Method D86–96 (incorporated by reference as specified in § 60.17).

(g) An owner or operator may use the following provisions instead of § 60.485a(b)(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 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 § 60.486a(e)(8). Divide these readings by the initial calibration values for each scale 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.

§ 60.5402a What are the alternative means of emission limitations for GHG and VOC equipment leaks from onshore natural gas processing plants?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in GHG and VOC emissions at least equivalent to the reduction in GHG and VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the **Federal Register**, a notice permitting the use of that alternative means for the purpose of compliance with that standard. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.

(d) An application submitted under paragraph (c) of this section must meet the following criteria:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.

(2) The application must include operation, maintenance and other provisions necessary to assure reduction in methane and VOC emissions at least equivalent to the reduction in methane and VOC emissions achieved under the design, equipment, work practice or operational standard in paragraph (a) of this section by including the information specified in paragraphs (d)(1)(i) through (x) of this section.

(i) A description of the technology or process.

(ii) The monitoring instrument and measurement technology or process.

(iii) A description of performance based procedures (i.e. method) and data quality indicators for precision and bias; the method detection limit of the technology or process.

(iv) The action criteria and level at which a fugitive emission exists.

(v) Any initial and ongoing quality assurance/quality control measures.

(vi) Timeframes for conducting ongoing quality assurance/quality control.

(vii) Field data verifying viability and detection capabilities of the technology or process.

(viii) Frequency of measurements.

(ix) Minimum data availability.

(x) Any restrictions for using the technology or process.

(3) The application must include initial and continuous compliance procedures including recordkeeping and reporting.

§ 60.5405a What standards apply to sweetening unit affected facilities at onshore natural gas processing plants?

(a) During the initial performance test required by § 60.8(b), you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_i) to be determined from Table 1 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

(b) After demonstrating compliance with the provisions of paragraph (a) of this section, you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_c) to be determined from Table 2 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

§ 60.5406a What test methods and procedures must I use for my sweetening unit affected facilities at onshore natural gas processing plants?

(a) In conducting the performance tests required in § 60.8, you must use the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b).

(b) During a performance test required by § 60.8, you must determine the minimum required reduction efficiencies (Z) of SO_2 emissions as required in § 60.5405a(a) and (b) as follows:

(1) The average sulfur feed rate (X) must be computed as follows:

$$X = KQ_aY$$

Where:

X = average sulfur feed rate, Mg/D (LT/D).
Q_a = average volumetric flow rate of acid gas from sweetening unit, dscm/day (dscf/day).
Y = average H_2S concentration in acid gas feed from sweetening unit, percent by volume, expressed as a decimal.
K = (32 kg S/kg-mole)/((24.04 dscm/kg-mole)(1000 kg S/Mg)).
= 1.331×10^{-3}Mg/dscm, for metric units.
= (32 lb S/lb-mole)/((385.36 dscf/lb-mole)(2240 lb S/long ton)).
= 3.707×10^{-5} long ton/dscf, for English units.

(2) You must use the continuous readings from the process flowmeter to determine the average volumetric flow rate (Q_a) in dscm/day (dscf/day) of the acid gas from the sweetening unit for each run.

(3) You must use the Tutwiler procedure in § 60.5408a or a chromatographic procedure following ASTM E260–96 (incorporated by reference as specified in § 60.17) to determine the H_2S concentration in the acid gas feed from the sweetening unit (Y). At least one sample per hour (at equally spaced intervals) must be taken during each 4-hour run. The arithmetic mean of all samples must be the average H_2S concentration (Y) on a dry basis for the run. By multiplying the result from the Tutwiler procedure by 1.62×10^{-3}, the units gr/100 scf are converted to volume percent.

(4) Using the information from paragraphs (b)(1) and (3) of this section, Tables 1 and 2 of this subpart must be used to determine the required initial (Z_i) and continuous (Z_c) reduction efficiencies of SO_2 emissions.

(c) You must determine compliance with the SO_2 standards in § 60.5405a(a) or (b) as follows:

(1) You must compute the emission reduction efficiency (R) achieved by the sulfur recovery technology for each run using the following equation:

$$R = (100S)/(S + E)$$

(2) You must use the level indicators or manual soundings to measure the liquid sulfur accumulation rate in the product storage vessels. You must use readings taken at the beginning and end of each run, the tank geometry, sulfur density at the storage temperature, and sample duration to determine the sulfur production rate (S) in kg/hr (lb/hr) for each run.

(3) You must compute the emission rate of sulfur for each run as follows:

$$E = C_eQ_{sd}/K_1$$

Where:

E = emission rate of sulfur per run, kg/hr.
C_e = concentration of sulfur equivalent (SO^{2+} reduced sulfur), g/dscm (lb/dscf).
Q_{sd} = volumetric flow rate of effluent gas, dscm/hr (dscf/hr).
K_1 = conversion factor, 1000 g/kg (7000 gr/lb).

(4) The concentration (C_e) of sulfur equivalent must be the sum of the SO_2 and TRS concentrations, after being converted to sulfur equivalents. For each run and each of the test methods specified in this paragraph (c) of this section, you must use a sampling time of at least 4 hours. You must use Method 1 of appendix A–1 of this part to select the sampling site. The sampling point in the duct must be at

the centroid of the cross-section if the area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 in) if the cross-sectional area is 5 m^2 or more, and the centroid is more than 1 m (39 in) from the wall.

(i) You must use Method 6 of appendix A–4 of this part to determine the SO_2 concentration. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration must be multiplied by 0.5×10^{-3} to convert the results to sulfur equivalent. In place of Method 6 of Appendix A of this part, you may use ANSI/ASME PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 60.17).

(ii) You must use Method 15 of appendix A–5 of this part to determine the TRS concentration from reduction-type devices or where the oxygen content of the effluent gas is less than 1.0 percent by volume. The sampling rate must be at least 3 liters/min (0.1 ft^3/min) to insure minimum residence time in the sample line. You must take sixteen samples at 15-minute intervals. The arithmetic average of all the samples must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iii) You must use Method 16A of appendix A–6 of this part or Method 15 of appendix A–5 of this part or ANSI/ASME PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 60.17) to determine the reduced sulfur concentration from oxidation-type devices or where the oxygen content of the effluent gas is greater than 1.0 percent by volume. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iv) You must use Method 2 of appendix A–1 of this part to determine the volumetric flow rate of the effluent gas. A velocity traverse must be conducted at the beginning and end of each run. The arithmetic average of the two measurements must be used to calculate the volumetric flow rate (Q_{sd}) for the run. For the determination of the effluent gas molecular weight, a single integrated sample over the 4-hour period may be taken and analyzed or grab samples at 1-hour intervals may be taken, analyzed, and averaged. For the moisture content, you must take two samples of at least 0.10 dscm (3.5 dscf) and 10 minutes at the beginning of the 4-hour run and near the end of the time period. The arithmetic average of the two runs must be the moisture content for the run.

§ 60.5407a What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?

(a) If your sweetening unit affected facility is located at an onshore natural gas processing plant and is subject to the provisions of § 60.5405a(a) or (b) you must install, calibrate, maintain, and operate monitoring devices or perform measurements to determine the following operations information on a daily basis:

(1) The accumulation of sulfur product over each 24-hour period. The monitoring method may incorporate the use of an instrument to measure and record the liquid sulfur production rate, or may be a procedure for measuring and recording the sulfur liquid levels in the storage vessels with a level indicator or by manual soundings, with subsequent calculation of the sulfur production rate based on the tank geometry, stored sulfur density, and elapsed time between readings. The method must be designed to be accurate within ±2 percent of the 24-hour sulfur accumulation.

(2) The H_2S concentration in the acid gas from the sweetening unit for each 24-hour period. At least one sample per 24-hour period must be collected and analyzed using the equation specified in § 60.5406a(b)(1). The Administrator may require you to demonstrate that the H_2S concentration obtained from one or more samples over a 24-hour period is within ±20 percent of the average of 12 samples collected at equally spaced intervals during the 24-hour period. In instances where the H_2S concentration of a single sample is not within ±20 percent of the average of the 12 equally spaced samples, the Administrator may require a more frequent sampling schedule.

(3) The average acid gas flow rate from the sweetening unit. You must install and operate a monitoring device to continuously measure the flow rate of acid gas. The monitoring device reading must be recorded at least once per hour during each 24-hour period. The average acid gas flow rate must be computed from the individual readings.

(4) The sulfur feed rate (X). For each 24-hour period, you must compute X using the equation specified in § 60.5406a(b)(1).

(5) The required sulfur dioxide emission reduction efficiency for the 24-hour period. You must use the sulfur feed rate and the H_2S concentration in the acid gas for the 24-hour period, as applicable, to determine the required reduction efficiency in accordance with the provisions of § 60.5405a(b).

(b) Where compliance is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device, you must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors as follows:

(1) A continuous monitoring system to measure the total sulfur emission rate (E) of SO_2 in the gases discharged to the atmosphere. The SO_2 emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405a(b) will be between 30 percent and 70 percent of the measurement range of the instrument system.

(2) Except as provided in paragraph (b)(3) of this section: A monitoring device to measure the temperature of the gas leaving the combustion zone of the incinerator, if compliance with § 60.5405a(a) is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device. The monitoring device must be certified by the manufacturer to be accurate to within ±1 percent of the temperature being measured.

(3) When performance tests are conducted under the provision of § 60.8 to demonstrate compliance with the standards under § 60.5405a, the temperature of the gas leaving the incinerator combustion zone must be determined using the monitoring device. If the volumetric ratio of sulfur dioxide to sulfur dioxide plus total reduced sulfur (expressed as SO_2) in the gas leaving the incinerator is equal to or less than 0.98, then temperature monitoring may be used to demonstrate that sulfur dioxide emission monitoring is sufficient to determine total sulfur emissions. At all times during the operation of the facility, you must maintain the average temperature of the gas leaving the combustion zone of the incinerator at or above the appropriate level determined during the most recent performance test to ensure the sulfur compound oxidation criteria are met. Operation at lower average temperatures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. You may request that the minimum incinerator temperature be reestablished by conducting new performance tests under § 60.8.

(4) Upon promulgation of a performance specification of continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants, you may, as an alternative to paragraph (b)(2) of this section, install, calibrate, maintain, and operate a continuous emission monitoring system for total reduced sulfur compounds as required in paragraph (d) of this section in addition to a sulfur dioxide emission monitoring system. The sum of the equivalent sulfur mass emission rates from the two monitoring systems must be used to compute the total sulfur emission rate (E).

(c) Where compliance is achieved through the use of a reduction control system not followed by a continually operated incineration device, you must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds as SO_2 equivalent in the gases discharged to the atmosphere. The SO_2 equivalent compound emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405a(b) will be between 30 and 70 percent of the measurement range of the system. This requirement becomes effective upon promulgation of a performance specification for continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants.

(d) For those sources required to comply with paragraph (b) or (c) of this section, you must calculate the average sulfur emission reduction efficiency achieved (R) for each 24-hour clock interval. The 24-hour interval may begin and end at any selected clock time, but must be consistent. You must compute the 24-hour average reduction efficiency (R) based on the 24-hour average sulfur production rate (S) and sulfur emission rate (E), using the equation in § 60.5406a(c)(1).

(1) You must use data obtained from the sulfur production rate monitoring device specified in paragraph (a) of this section to determine S.

(2) You must use data obtained from the sulfur emission rate monitoring systems specified in paragraphs (b) or (c) of this section to calculate a 24-hour average for the sulfur emission rate (E). The monitoring system must provide at least one data point in each successive 15-minute interval. You must use at least two data points to calculate each 1-hour average. You must use a minimum of 18 1-hour averages to compute each 24-hour average.

(e) In lieu of complying with paragraphs (b) or (c) of this section, those sources with a design capacity of less than 152 Mg/D (150 LT/D) of H_2S expressed as sulfur may calculate the sulfur emission reduction efficiency achieved for each 24-hour period by:

$$R = \frac{K_2 S}{X}$$

Where:

R = The sulfur dioxide removal efficiency achieved during the 24-hour period, percent.

K_2 = Conversion factor, 0.02400 Mg/D per kg/hr (0.01071 LT/D per lb/hr).

S = The sulfur production rate during the 24-hour period, kg/hr (lb/hr).

X = The sulfur feed rate in the acid gas, Mg/D (LT/D).

(f) The monitoring devices required in paragraphs (b)(1), (b)(3) and (c) of this section must be calibrated at least annually according to the manufacturer's specifications, as required by § 60.13(b).

(g) The continuous emission monitoring systems required in paragraphs (b)(1), (b)(3), and (c) of this section must be subject to the emission monitoring requirements of § 60.13 of the General Provisions. For conducting the continuous emission monitoring system performance evaluation required by § 60.13(c), Performance Specification 2 of appendix B of this part must apply, and Method 6 of appendix A–4 of this part must be used for systems required by paragraph (b) of this section. In place of Method 6 of appendix A–4 of this part, ASME PTC 19.10–1981 (incorporated by reference—see § 60.17) may be used.

§ 60.5408a What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?

The Tutwiler procedure may be found in the Gas Engineers Handbook, Fuel Gas Engineering practices, The Industrial Press, 93 Worth Street, New York, NY, 1966, First Edition, Second Printing, page 6/25 (Docket A–80–20–A, Entry II–I–67).

(a) When an instantaneous sample is desired and H_2S concentration is 10 grains per 1000 cubic foot or more, a 100 ml Tutwiler burette is used. For concentrations less than 10 grains, a 500 ml Tutwiler burette and more dilute solutions are used. In principle, this method consists of titrating hydrogen sulfide in a gas sample directly with a standard solution of iodine.

(b) *Apparatus.* (See Figure 1 of this subpart.) A 100 or 500 ml capacity Tutwiler burette, with two-way glass stopcock at bottom and three-way stopcock at top that connect either with inlet tubulature or glass-stoppered cylinder, 10 ml capacity, graduated in 0.1 ml subdivision; rubber tubing connecting burette with leveling bottle.

(c) *Reagents.* (1) Iodine stock solution, 0.1N. Weight 12.7 g iodine, and 20 to 25 g cp potassium iodide (KI) for each liter of solution. Dissolve KI in as little water as necessary; dissolve iodine in concentrated KI solution, make up to proper volume, and store in glass-stoppered brown glass bottle.

(2) Standard iodine solution, 1 ml=0.001771 g I. Transfer 33.7 ml of above 0.1N stock solution into a 250 ml volumetric flask; add water to mark and mix well. Then, for 100 ml sample of gas, 1 ml of standard iodine solution is equivalent to 100 grains H_2S per cubic feet of gas.

(3) Starch solution. Rub into a thin paste about one teaspoonful of wheat starch with a little water; pour into about a pint of boiling water; stir; let cool and decant off clear solution. Make fresh solution every few days.

(d) *Procedure.* Fill leveling bulb with starch solution. Raise (L), open cock (G), open (F) to (A), and close (F) when solutions starts to run out of gas inlet. Close (G). Purge gas sampling line and connect with (A). Lower (L) and open (F) and (G). When liquid level is several ml past the 100 ml mark, close (G) and (F), and disconnect sampling tube. Open (G) and bring starch solution to 100 ml mark by raising (L); then close (G). Open (F) momentarily, to bring gas in burette to atmospheric pressure, and close (F). Open (G), bring liquid level down to 10 ml mark by lowering (L). Close (G), clamp rubber tubing near (E) and disconnect it from burette. Rinse graduated cylinder with a standard iodine solution (0.00171 g I per ml); fill cylinder and record reading. Introduce successive small amounts of iodine through (F); shake well after each addition; continue until a faint permanent blue color is obtained. Record reading; subtract from previous reading, and call difference D.

(e) With every fresh stock of starch solution perform a blank test as follows: Introduce fresh starch solution into burette up to 100 ml mark. Close (F) and (G). Lower (L) and open (G). When liquid level reaches the 10 ml mark, close (G). With air in burette, titrate as during a test and up to same end point. Call ml of iodine used C. Then,

Grains H_2S per 100 cubic foot of gas = 100 (D–C)

(f) Greater sensitivity can be attained if a 500 ml capacity Tutwiler burette is used with a more dilute (0.001N) iodine solution. Concentrations less than 1.0 grains per 100 cubic foot can be determined in this way. Usually, the starch-iodine end point is much less distinct, and a blank determination of end point, with H_2S-free gas or air, is required.

BILLING CODE 6560–50–P

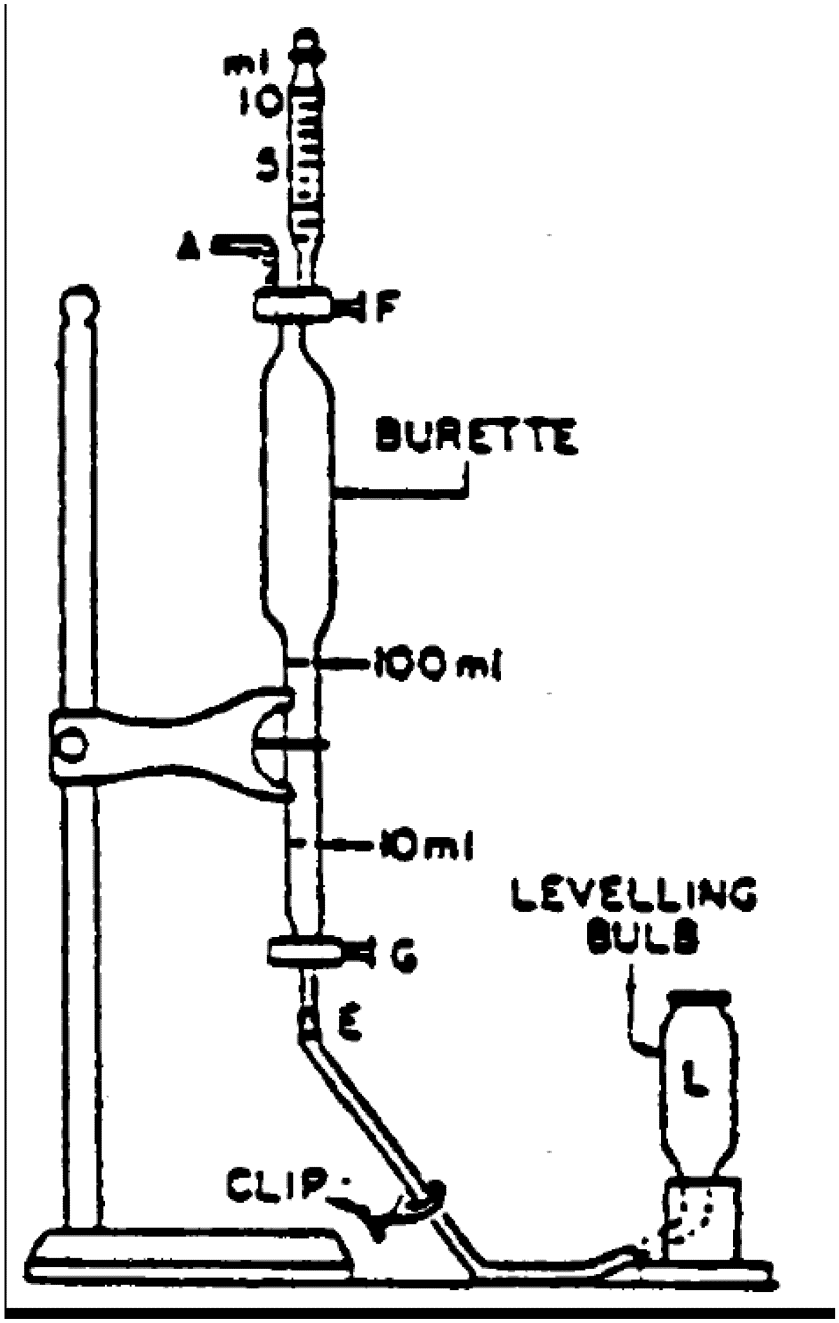

Figure 1. Tutwiler burette (lettered items mentioned in text).

BILLING CODE 6560–50–C

§ 60.5410a How do I demonstrate initial compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, collection of fugitive emissions components at a compressor station, and equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?

You must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (j) of this section. The initial compliance period begins on August 2, 2016, or upon initial startup, whichever is later, and ends no later than 1 year after the initial startup date for your affected facility or no later than 1 year after August 2, 2016. The initial compliance period may be less than one full year.

(a) To achieve initial compliance with the methane and VOC standards for each well completion operation conducted at your well affected facility you must comply with paragraphs (a)(1) through (4) of this section.

(1) You must submit the notification required in § 60.5420a(a)(2).

(2) You must submit the initial annual report for your well affected facility as required in § 60.5420a(b)(1) and (2).

(3) You must maintain a log of records as specified in § 60.5420a(c)(1)(i) through (iv), as applicable, for each well completion operation conducted during the initial compliance period. If you meet the exemption for wells with a GOR less than 300 scf per stock barrel of oil produced, you do not have to maintain the records in § 60.5420a(c)(1)(i) through (iv) and must maintain the record in § 60.5420a(c)(1)(vi).

(4) For each well affected facility subject to both § 60.5375a(a)(1) and (3), as an alternative to retaining the records specified in § 60.5420a(c)(1)(i) through (iv), you may maintain records in accordance with § 60.5420a(c)(1)(v) of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file showing the equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to the gas flow line and the completion combustion device (if applicable) connected to and operating at each well completion operation that occurred during the initial compliance period. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the equipment connected and operating at each well completion operation 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.

(b)(1) To achieve initial compliance with standards for your centrifugal compressor affected facility you must reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater as required by § 60.5380a(a) and as demonstrated by the requirements of § 60.5413a.

(2) 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 § 60.5411a(b) that is connected through a closed vent system that meets the requirements of § 60.5411a(a) and (d) and is routed to a control device that meets the conditions specified in § 60.5412a(a), (b) and (c). 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 must conduct an initial performance test as required in § 60.5413a within 180 days after initial startup or by August 2, 2016, whichever is later, and you must comply with the continuous compliance requirements in § 60.5415a(b).

(4) You must conduct the initial inspections required in § 60.5416a(a) and (b).

(5) You must install and operate the continuous parameter monitoring systems in accordance with § 60.5417a(a) through (g), as applicable.

(6)]Reserved]

(7) You must submit the initial annual report for your centrifugal compressor affected facility as required in § 60.5420a(b)(1) and (3).

(8) You must maintain the records as specified in § 60.5420a(c)(2), (6) through (11), and (17), as applicable.

(c) To achieve initial compliance with the standards for each reciprocating compressor affected facility you must comply with paragraphs (c)(1) through (4) of this section.

(1) If complying with § 60.5385a(a)(1) or (2), during the initial compliance period, you must continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement.

(2) If complying with § 60.5385a(a)(3), you must operate the rod packing emissions collection system under negative pressure and route emissions to a process through a closed vent system that meets the requirements of § 60.5411a(a) and (d).

(3) You must submit the initial annual report for your reciprocating compressor as required in § 60.5420a(b)(1) and (4).

(4) You must maintain the records as specified in § 60.5420a(c)(3) for each reciprocating compressor affected facility.

(d) To achieve initial compliance with methane and VOC emission standards for your pneumatic controller affected facility you must comply with the requirements specified in paragraphs (d)(1) through (6) of this section, as applicable.

(1) You must demonstrate initial compliance by maintaining records as specified in § 60.5420a(c)(4)(ii) of your determination that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required as specified in § 60.5390a(b)(1) or (c)(1).

(2) If you own or operate a pneumatic controller affected facility located at a natural gas processing plant, your pneumatic controller must be driven by a gas other than natural gas, resulting in zero natural gas emissions.

(3) If you own or operate a pneumatic controller affected facility located other than at a natural gas processing plant, the controller manufacturer's design specifications for the controller must indicate that the controller emits less than or equal to 6 standard cubic feet of gas per hour.

(4) You must tag each new pneumatic controller affected facility according to the requirements of § 60.5390a(b)(2) or (c)(2).

(5) You must include the information in paragraph (d)(1) of this section and a listing of the pneumatic controller affected facilities specified in paragraphs (d)(2) and (3) of this section in the initial annual report submitted for your pneumatic controller affected facilities constructed, modified or reconstructed during the period covered by the annual report according to the requirements of § 60.5420a(b)(1) and (5).

(6) You must maintain the records as specified in § 60.5420a(c)(4) for each pneumatic controller affected facility.

(e) To achieve initial compliance with emission standards for your pneumatic pump affected facility you must comply with the requirements specified in paragraphs (e)(1) through (7) of this section, as applicable.

(1) If you own or operate a pneumatic pump affected facility located at a natural gas processing plant, your pneumatic pump must be driven by a gas other than natural gas, resulting in zero natural gas emissions.

(2) If you own or operate a pneumatic pump affected facility not located at a natural gas processing plant, you must reduce emissions in accordance § 60.5393a(b)(1) or (b)(2), and you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of § 60.5411a(a) and (d).

(3) If you own or operate a pneumatic pump affected facility not located at a natural gas processing plant and there is no control device or process available on site, you must submit the certification in 60.5420a(b)(8)(i)(A).

(4) If you own or operate a pneumatic pump affected facility not located at a natural gas processing plant or a greenfield 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 § 60.5420a(b)(8)(i)(B).

(5) If you own or operate a pneumatic pump affected facility not located other than at a natural gas processing plant and you reduce emissions in accordance with § 60.5393a(b)(4), you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of § 60.5411a(c) and (d).

(6) You must submit the initial annual report for your pneumatic pump affected facility required in § 60.5420a(b)(1) and (8).

(7) You must maintain the records as specified in § 60.5420a(c)(6), (8) through (10), (16), and (17), as applicable, for each pneumatic pump affected facility.

(f) For affected facilities at onshore natural gas processing plants, initial compliance with the methane and VOC standards is demonstrated if you are in compliance with the requirements of § 60.5400a.

(g) For sweetening unit affected facilities at onshore natural gas processing plants, initial compliance is demonstrated according to paragraphs (g)(1) through (3) of this section.

(1) To determine compliance with the standards for SO_2 specified in § 60.5405a(a), during the initial performance test as required by § 60.8, the minimum required sulfur dioxide emission reduction efficiency (Z_i) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology as specified in paragraphs (g)(1)(i) and (ii) of this section.

(i) If $R \geq Z_i$, your affected facility is in compliance.

(ii) If $R < Z_i$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in § 60.5406a(c)(1).

(3) You must submit the results of paragraphs (g)(1) and (2) of this section in the initial annual report submitted for your sweetening unit affected facilities at onshore natural gas processing plants.

(h) For each storage vessel affected facility, you must comply with paragraphs (h)(1) through (6) of this section. You must demonstrate initial compliance by August 2, 2016, or within 60 days after startup, whichever is later.

(1) You must determine the potential VOC emission rate as specified in § 60.5365a(e).

(2) You must reduce VOC emissions in accordance with § 60.5395a(a).

(3) If you use a control device to reduce emissions, you must equip the storage vessel with a cover that meets the requirements of § 60.5411a(b) and is connected through a closed vent system that meets the requirements of § 60.5411a(c) and (d) to a control device that meets the conditions specified in § 60.5412a(d) within 60 days after startup for storage vessels constructed, modified or reconstructed at well sites with no other wells in production, or upon startup for storage vessels constructed, modified or reconstructed at well sites with one or more wells already in production.

(4) You must conduct an initial performance test as required in § 60.5413a within 180 days after initial startup or within 180 days of August 2, 2016, whichever is later, and you must comply with the continuous compliance requirements in § 60.5415a(e).

(5) You must submit the information required for your storage vessel affected facility in your initial annual report as specified in § 60.5420a(b)(1) and (6).

(6) You must maintain the records required for your storage vessel affected facility, as specified in § 60.5420a(c)(5) through (8), (12) through (14), and (17), as applicable, for each storage vessel affected facility.

(i) For each storage vessel affected facility that complies by using a floating roof, you must submit a statement that you are complying with § 60.112(b)(a)(1) or (2) in accordance with § 60.5395a(b)(2) with the initial annual report specified in § 60.5420a(b).

(j) 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 compressor station, you must comply with paragraphs (j)(1) through (5) of this section.

(1) You must develop a fugitive emissions monitoring plan as required in § 60.5397a(b)(c), and (d).

(2) You must conduct an initial monitoring survey as required in § 60.5397a(f).

(3) You must maintain the records specified in § 60.5420a(c)(15).

(4) You must repair each identified source of fugitive emissions for each affected facility as required in § 60.5397a(h).

(5) 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 compressor station compressor station as required in § 60.5420a(b)(1) and (7).

§ 60.5411a What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing emissions from centrifugal compressor wet seal fluid degassing systems, reciprocating compressors, pneumatic pumps and storage vessels?

You must meet the applicable requirements of this section for each cover and closed vent system used to comply with the emission standards for your centrifugal compressor wet seal degassing systems, reciprocating compressors, pneumatic pumps and storage vessels.

(a) Closed vent system requirements for reciprocating compressors, centrifugal compressor wet seal degassing systems and pneumatic pumps.

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the reciprocating compressor rod packing emissions collection system, the wet seal fluid degassing system or pneumatic pump to a control device or to a process. For reciprocating and centrifugal compressors, the closed vent system must route all gases, vapors, and fumes to a control device that meets the requirements specified in § 60.5412a(a) through (c).

(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by § 60.5416a(b).

(3) You must meet the requirements specified in paragraphs (a)(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.

(i) Except as provided in paragraph (a)(3)(ii) of this section, you must comply with either paragraph (a)(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 § 60.5416a(a)(4)(i) 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 from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to § 60.5420a(c)(8).

(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 (a)(3)(i) of this section.

(b) Cover requirements for storage vessels and centrifugal compressor wet seal fluid degassing systems.

(1) The cover and all openings on the cover (*e.g.*, access hatches, sampling ports, pressure relief devices and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel or wet seal fluid degassing system.

(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 (a) or (c), and (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 weighted mechanism or equivalent, 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.

(c) Closed vent system requirements for storage vessel affected facilities using a control device or routing emissions to a process.

(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 that meets the requirements specified in § 60.5412a(c) and (d), 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 paragraphs (c)(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 (c)(3)(ii) of this section, you must comply with either paragraph (c)(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 from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to § 60.5420a(c)(8).

(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 (c)(3)(i) of this section.

(d) Closed vent systems requirements for centrifugal compressor wet seal fluid degassing systems, reciprocating compressors, pneumatic pumps and storage vessels using a control device or routing emissions to a process.

(1) 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 and that the control device is of sufficient design and capacity to accommodate all emissions from the affected facility and have it certified by a qualified professional engineer in accordance with paragraphs (d)(1)(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 subpart OOOOa of 40 CFR part 60. 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)(1)(i) of this section.

§ 60.5412a What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my centrifugal compressor, and storage vessel affected facilities?

You must meet the applicable requirements of this section for each control device used to comply with the emission standards for your centrifugal compressor affected facility, or storage vessel affected facility.

(a) Each control device used to meet the emission reduction standard in § 60.5380a(a)(1) for your centrifugal compressor affected facility 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 § 60.5413a(d), which meets the criteria in § 60.5413a(d)(11) and meet the continuous compliance requirements in § 60.5413a(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 methane and VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413a(b), with the exceptions noted in § 60.5413a(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 § 60.5413a(b), with the exceptions noted in § 60.5413a(a).

(iii) You must operate at a minimum temperature of 760 °Celsius, provided the control device has demonstrated, during the performance test conducted under § 60.5413a(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 methane and VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413a(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 § 60.5413a(c).

(3) You must design and operate a flare in accordance with the requirements of § 60.18(b), and you must conduct the compliance determination using Method 22 of appendix A–7 of this part to determine visible emissions.

(b) You must operate each control device installed on your centrifugal compressor affected facility 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 subpart at all times when gases, vapors, and fumes are vented from the wet seal fluid degassing system affected facility as required under § 60.5380a(a)(1) through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

(2) For each control device monitored in accordance with the requirements of § 60.5417a(a) through (g), you must demonstrate compliance according to the requirements of § 60.5415a(b)(2), as applicable.

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) or (d)(2) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (c)(1) or (2) of this section.

(1) 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 § 60.5413a(c)(2) or (3) or according to the design required in paragraph (d)(2) 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 § 60.5420a(c)(10) and (12).

(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 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 an operating organic air emission controls in accordance with an emissions standard for VOC under another subpart in 40 CFR part 63 or this part.

(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.

(d) Each control device used to meet the emission reduction standard in § 60.5395a(a)(2) for your storage vessel affected facility must be installed according to paragraphs (d)(1) through (4) of this section, as applicable. As an alternative to paragraph (d)(1) of this section, you may install a control device model tested under § 60.5413a(d), which meets the criteria in § 60.5413a(d)(11) and meet the continuous compliance requirements in § 60.5413a(e).

(1) For each combustion control device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) you must meet the requirements in paragraphs (d)(1)(i) through (iv) of this section.

(i) Ensure that each enclosed combustion control device is maintained in a leak free condition.

(ii) Install and operate a continuous burning pilot flame.

(iii) Operate the combustion control device with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period. A visible emissions test using section 11 of EPA Method 22 of appendix A–7 of this part 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 of appendix A–7 of this part visual observation as described in this paragraph.

(iv) 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 (A) through (D) of this section.

(A) 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 § 60.5413a(b).

(B) 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 § 60.5413a(b).

(C) You must operate at a minimum temperature of 760 °Celsius, provided the control device has demonstrated, during the performance test conducted under § 60.5413a(b), that combustion zone temperature is an indicator of destruction efficiency.

(D) 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. A carbon replacement schedule must be included in the design of the carbon adsorption system.

(3) You must design and operate a flare in accordance with the requirements of § 60.18(b), and you must conduct the compliance determination using Method 22 of appendix A–7 of this part to determine visible emissions.

(4) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the storage vessel affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

§ 60.5413a What are the performance testing procedures for control devices used to demonstrate compliance at my centrifugal compressor and storage vessel affected facilities?

This section applies to the performance testing of control devices used to demonstrate compliance with the emissions standards for your centrifugal compressor affected facility or storage vessel affected facility. You must demonstrate that a control device achieves the performance requirements of § 60.5412a(a)(1) or (2) or (d)(1) or (2) 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 control device performance tests conducted by the manufacturer applicable to storage vessel and centrifugal compressor affected facilities.

(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 § 60.18(b). You must conduct the compliance determination using Method 22 of appendix A–7 of this part 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 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 § 60.5420(b)(9) 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 § 60.5420a(b)(9) 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 § 60.8(b).

(7) A control device whose model can be demonstrated to meet the performance requirements of § 60.5412a(a)(1) or (d)(1) 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 § 60.5412a(a)(1) or (2) or (d)(1) or (2). 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 Method 1 or 1A of appendix A–1 of this part, as appropriate, to select the sampling sites specified in paragraphs (b)(1)(i) and (ii) of this section. Any references to particulate mentioned in 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 a control device percent reduction requirement.

(ii) The sampling site must be located at the outlet of the combustion device to determine compliance with a TOC exhaust gas concentration limit.

(2) You must determine the gas volumetric flowrate using Method 2, 2A, 2C, or 2D of appendix A–2 of this part, as appropriate.

(3) To determine compliance with the control device percent reduction performance requirement in § 60.5412a(a)(1)(i), (a)(2) or (d)(1)(iv)(A), you must use Method 25A of appendix A–7 of this part. You must use Method 4 of appendix A–3 of this part to convert the 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 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 Method 25A of appendix A–7 of this part to measure TOC, as propane, to determine compliance with the TOC exhaust gas concentration limit specified in § 60.5412a(a)(1)(ii) or (d)(1)(iv)(B). You may also use Method 18 of appendix A–6 of this part to measure methane and ethane. You may subtract the measured concentration of methane and ethane from the 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 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 Method 25A sample.

(ii) You may subtract the concentration of methane and ethane from the 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 Method 3A or 3B of appendix A–2 of this part, 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 initial startup for your affected facility. You must submit the performance test results as required in § 60.5420a(b)(9).

(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. You must submit the periodic performance test results as specified in § 60.5420a(b)(9).

(A) A control device whose model is tested under, and meets the criteria of paragraph (d) of this section. For centrifugal compressor affected facilities, if you do not continuously monitor the gas flow rate in accordance with § 60.5417a(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 § 60.5412a(a)(1)(ii) or (d)(1)(iv)(B) and that establishes a correlation between firebox or combustion chamber temperature and the TOC performance level. For centrifugal compressor affected facilities, you must establish a limit on temperature in accordance with § 60.5417a(f) and continuously monitor the temperature as required by § 60.5417a(d).

(c) *Control device design analysis to meet the requirements of § 60.5412a(a)(2) or (d)(2).* (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 shall incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(4) If you and the Administrator 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 Administrator may choose to have an authorized representative observe the performance test.

(d) *Performance testing for combustion control devices—manufacturers' performance test.* (1) This paragraph (d) 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 1-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 Method 2A of appendix A–1 of this part (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 Method 2A of appendix A–1 of this part. 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 (incorporated by reference as specified in § 60.17).

(B) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945–03 (incorporated by reference as specified in § 60.17).

(C) Higher heating value using ASTM D3588–98 or ASTM D4891–89 (incorporated by reference as specified in § 60.17).

(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 Method 1 of appendix A–1 of this part for determining flow measurement traverse point location, and Method 2 of appendix A–1 of this part 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 Method 4 of appendix A–3 of this part following the procedure specified in (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 Method 3C of appendix A–2 of this part 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 Method 4 of appendix A–3 of this part. Traverse both ports with the sampling train required by Method 4 of appendix A–3 of this part during each test run. Ambient air must not be introduced into the integrated bag sample required by Method 3C of appendix A–2 of this part during the port change.

(iii) Excess air must be determined using resultant data from the EPA Method 3C tests and EPA Method 3B of appendix A–2 of this part, equation 3B–1, or ANSI/ASME PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 60.17).

(8) Carbon monoxide must be determined using Method 10 of appendix A–4 of this part. Run the test simultaneously with Method 25A of appendix A–7 of this part 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 by in paragraphs (d)(9)(i) through (vii) of this section.

(i) Conduct THC sampling using Method 25A of appendix A–7 of this part, 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 Method 25A 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,'' (incorporated by reference as specified in § 60.17).

(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 Method 3C of appendix A–2 of this part. 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 Method 22 of appendix A–7 of this part. 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 Method 22 of appendix A–7 of this part determined under paragraph (d)(10) of this section with no indication of visible emissions.

(B) Average results from Method 25A of appendix A–7 of this part determined 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 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 percent for THC, as propane. A control device model that demonstrates a destruction efficiency of 95 percent for THC, as propane, will meet the control requirement for 95 percent destruction of VOC and methane (if applicable) required under this subpart.

(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) of this section in the test report required by this section in accordance with § 60.5420a(b)(10). 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 Document Control Officer; Office of Air Quality Planning and Standards (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 (e) 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 criteria in paragraph (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, maintaining the records specified in § 60.5420a(c)(2) or (c)(5)(vi) and submitting the report specified in § 60.5420a(b)(10).

(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 of appendix A–7 of this part 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 repairs 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 a visual observation according to EPA Method 22 of appendix A–7 of this part 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.

§ 60.5415a How do I demonstrate continuous compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, and collection of fugitive emissions components at a compressor station affected facilities, and affected facilities at onshore natural gas processing plants?

(a) For each well affected facility, you must demonstrate continuous compliance by submitting the reports required by § 60.5420a(b)(1) and (2) and maintaining the records for each completion operation specified in § 60.5420a(c)(1).

(b) For each centrifugal compressor affected facility and each pneumatic pump affected facility, you must demonstrate continuous compliance according to paragraph (b)(3) of this section. For each centrifugal compressor affected facility, you also must demonstrate continuous compliance according to paragraphs (b)(1) and (2) of this section.

(1) You must reduce methane and 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 § 60.5412a(a) using the procedures specified in paragraphs (b)(2)(i) through (vii) of this section. If you use a condenser as the control device to achieve the requirements specified in § 60.5412a(a)(2), you may demonstrate compliance according to paragraph (b)(2)(viii) of this section. You may switch between compliance with paragraphs (b)(2)(i) through (vii) of this section and compliance with paragraph (b)(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 § 60.5417a(f)(1).

(ii) You must calculate the daily average of the applicable monitored parameter in accordance with § 60.5417a(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 (b)(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 (b)(2)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in § 60.5413a(d), compliance with the operating parameter limit is achieved when the criteria in § 60.5413a(e) are met.

(iv) You must operate the continuous monitoring system required in § 60.5417a(a) at all times the affected 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 § 60.5412a(a)(1) and you demonstrate compliance using the test procedures specified in § 60.5413a(b), or you use a flare designed and operated in accordance with § 60.18(b), you must comply with paragraphs (b)(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 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, 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 repairs 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 of appendix A–7 of this part visual observation as described in paragraph (b)(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 § 60.5412a(a)(2), you must demonstrate compliance using the procedures in paragraphs (b)(2)(viii)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to § 60.5417a(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with § 60.5417a(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (b)(2)(viii)(B) of this section and the condenser performance curve established under paragraph (b)(2)(viii)(A) of this section.

(D) Except as provided in paragraphs (b)(2)(viii)(D)(*1*) and (*2*) of this section, at the end of each operating day, you must calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (b)(2)(viii)(C) of this section.

(*1*) After the compliance dates specified in § 60.5370a(a), 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 after the compliance date. 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 after the compliance date specified in § 60.5370a(a), you must calculate the average TOC emission reduction as the TOC emission reduction averaged over the number of days between the current day and the applicable compliance date. 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 (b)(2)(viii)(D) of this section is equal to or greater than 95.0 percent.

(3) You must submit the annual reports required by 60.5420a(b)(1) and (3) and maintain the records as specified in § 60.5420a(c)(2), (6) through (11), and (17), as applicable.

(c) For each reciprocating compressor affected facility complying with § 60.5385a(a)(1) or (2), you must demonstrate continuous compliance according to paragraphs (c)(1) through (3) of this section. For each reciprocating compressor affected facility complying with § 60.5385a(a)(3), you must demonstrate continuous compliance according to paragraph (c)(4) of this section.

(1) You must continuously monitor the number of hours of operation for each reciprocating compressor affected facility or track the number of months since initial startup or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) You must submit the annual reports as required in § 60.5420a(b)(1) and (4) and maintain records as required in § 60.5420a(c)(3).

(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) You must operate the rod packing emissions collection system under negative pressure and continuously comply with the cover and closed vent requirements in § 60.5416a(a) and (b).

(d) For each pneumatic controller affected facility, you must demonstrate continuous compliance according to paragraphs (d)(1) through (3) of this section.

(1) You must continuously operate the pneumatic controllers as required in § 60.5390a(a), (b), or (c).

(2) You must submit the annual reports as required in § 60.5420a(b)(1) and (5).

(3) You must maintain records as required in § 60.5420a(c)(4).

(e) You must demonstrate continuous compliance according to paragraph (e)(3) of this section for each storage vessel affected facility, for which you are using a control device or routing emissions to a process to meet the requirement of § 60.5395a(a)(2).

(1)–(2) [Reserved]

(3) For each storage vessel affected facility, you must comply with paragraphs (e)(3)(i) and (ii) of this section.

(i) You must reduce VOC emissions as specified in § 60.5395a(a)(2).

(ii) For each control device installed to meet the requirements of § 60.5395a(a)(2), you must demonstrate continuous compliance with the performance requirements of § 60.5412a(d) for each storage vessel affected facility using the procedure specified in paragraph (e)(3)(ii)(A) and either (e)(3)(ii)(B) or (e)(3)(ii)(C) of this section.

(A) You must comply with § 60.5416a(c) for each cover and closed vent system.

(B) You must comply with § 60.5417a(h) for each control device.

(C) Each closed vent system that routes emissions to a process must be operated as specified in § 60.5411a(c)(2) and (3).

(f) For affected facilities at onshore natural gas processing plants, continuous compliance with methane and VOC requirements is demonstrated if you are in compliance with the requirements of § 60.5400a.

(g) For each sweetening unit affected facility at onshore natural gas processing plants, you must demonstrate continuous compliance with the standards for SO_2 specified in § 60.5405a(b) according to paragraphs (g)(1) and (2) of this section.

(1) The minimum required SO_2 emission reduction efficiency (Z_c) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology.

(i) If $R \geq Z_c$, your affected facility is in compliance.

(ii) If $R < Z_c$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in § 60.5406a(c)(1).

(h) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, you must demonstrate continuous compliance with the fugitive emission standards specified in § 60.5397a according to paragraphs (h)(1) through (4) of this section.

(1) You must conduct periodic monitoring surveys as required in § 60.5397a(g).

(2) You must repair or replace each identified source of fugitive emissions as required in § 60.5397a(h).

(3) You must maintain records as specified in § 60.5420a(c)(15).

(4) You must submit annual reports for collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station as required in § 60.5420a(b)(1) and (7).

§ 60.5416a What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my centrifugal compressor, reciprocating compressor, pneumatic pump and storage vessel affected facilities?

For each closed vent system or cover at your storage vessel, centrifugal compressor, reciprocating compressor and pneumatic pump affected facilities, you must comply with the applicable requirements of paragraphs (a) through (c) of this section.

(a) Inspections for closed vent systems and covers installed on each centrifugal compressor, reciprocating compressor or pneumatic pump affected facility. Except as provided in paragraphs (b)(11) and (12) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a)(1) and (2) of this section, inspect each cover according to the procedures and schedule specified in paragraph (a)(3) of this section, and inspect each bypass device according to the procedures of paragraph (a)(4) of this section.

(1) 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)(i) and (ii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(ii) 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 (b) of this section to demonstrate that it operates with no detectable emissions following any time the component is repaired or replaced or the connection is unsealed. You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(2) For closed vent system components other than those specified in paragraph (a)(1) of this section, you must meet the requirements of paragraphs (a)(2)(i) through (iii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(ii) Conduct annual inspections according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the components or connections operate with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(iii) 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 as specified in § 60.5420a(c)(6).

(3) For each cover, you must meet the requirements in paragraphs (a)(3)(i) and (ii) of this section.

(i) 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. 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.

(ii) You must initially conduct the inspections specified in paragraph (a)(3)(i) 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 (b)(11) and (12) of this section. You must maintain records of the inspection results as specified in § 60.5420a(c)(7).

(4) For each bypass device, except as provided for in § 60.5411a(c)(3)(ii), you must meet the requirements of paragraphs (a)(4)(i) or (ii) of this section.

(i) 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 steam away from the control device to the atmosphere.

(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 according to § 60.5420a(c)(8).

(b) No detectable emissions test methods and procedures. If you are required to conduct an inspection of a closed vent system or cover at your centrifugal compressor, reciprocating compressor, or pneumatic pump affected facility as specified in paragraphs (a)(1), (2), or (3) of this section, you must meet the requirements of paragraphs (b)(1) through (13) of this section.

(1) You must conduct the no detectable emissions test procedure in accordance with Method 21 of appendix A–7 of this part.

(2) The detection instrument must meet the performance criteria of Method 21 of appendix A–7 of this part, 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 Method 21 of appendix A–7 of this part.

(4) Calibration gases must be as specified in paragraphs (b)(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 Method 21 of appendix A–7 of this part.

(6) Your detection instrument must meet the performance criteria specified in paragraphs (b)(6)(i) and (ii) of this section.

(i) Except as provided in paragraph (b)(6)(ii) of this section, the detection instrument must meet the performance criteria of Method 21 of appendix A–7 of this part, except the instrument response factor criteria in section 8.1.1

of 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 organic hazardous air pollutants or 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 (b)(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 (b)(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 (b)(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 (b)(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 (b)(5) of this section with the applicable value for the potential leak interface as specified in paragraph (b)(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 (b)(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 (b)(9)(i) and (ii) of this section, except as provided in paragraph (b)(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 (b)(11)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) 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)(1), (2), or (3) 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 (b)(12)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) 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 § 60.5420a(c)(9).

(c) *Cover and closed vent system inspections for storage vessel affected facilities.* 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 (c)(1) of this section, inspect each cover according to the procedures and schedule specified in paragraph (c)(2) of this section, and inspect each bypass device according to the procedures of paragraph (c)(3) of this section. You must also comply with the requirements of (c)(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 (c)(1)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(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 (c)(2)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in § 60.5420a(c)(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 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 § 60.5411a(c)(3)(ii), you must meet the requirements of paragraphs (c)(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 § 60.5420a(c)(8).

(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 § 60.5420a(c)(8).

(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 (c)(4)(i) through (iii) of this section, except as provided in paragraph (c)(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 (c)(6)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (c)(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 (c)(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 (c)(7)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (c)(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.

§ 60.5417a What are the continuous control device monitoring requirements for my centrifugal compressor and storage vessel affected facilities?

You must meet the applicable requirements of this section to demonstrate continuous compliance for each control device used to meet emission standards for your storage vessel or centrifugal compressor affected facility.

(a) For each control device used to comply with the emission reduction standard for centrifugal compressor affected facilities in § 60.5380a(a)(1), 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 § 60.5412a(a)(3), you are exempt from the requirements of paragraphs (e) and (f) of this section. If you install and operate an enclosed combustion device which is not specifically listed in paragraph (d) of this section, you must demonstrate continuous compliance according to paragraphs (h)(1) through (h)(4) 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 are 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 § 60.13(b).

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 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 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 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 § 60.5413a(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 nonregenerative-type carbon adsorption system, you must monitor the design carbon replacement interval established using a design analysis performed as specified in § 60.5413a(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 § 60.5413a(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 § 60.5413a(b)(5)(ii), you are not required to continuously monitor the gas flow rate under paragraph (d)(1)(viii)(A) of this section.

(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 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 appendix B of this part. You must install, calibrate, and maintain the monitor according to the manufacturer's specifications.

(3) A continuous monitoring system that measures operating parameters other than those specified in paragraph (d)(1) or (2) of this section, upon approval of the Administrator as specified in § 60.13(i).

(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 § 60.5412a(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 § 60.5413a(b) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412a(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 § 60.5413a(c) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412a(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 § 60.5413a(d) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412a(a)(1), then your control device inlet gas flow rate must not exceed the maximum 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 § 60.5413a(b) to demonstrate that the condenser achieves the applicable performance requirements in § 60.5412a(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 § 60.5413a(c)(1) to demonstrate that the condenser achieves the applicable performance requirements specified in § 60.5412a(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 are subject to § 60.5412a(a)(2), a deviation occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 60.5415a(b)(2)(viii)(D) is less than 95.0 percent.

(3) If you are subject to § 60.5412a(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 § 60.5415a(b)(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 paragraph (g)(5)(i) or (ii) of this section are met.

(i) For each bypass line subject to § 60.5411a(a)(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 § 60.5411a(a)(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 § 60.5413a(d), a deviation occurs when the conditions of paragraphs (g)(6)(i) or (ii) of this section are met.

(i) The inlet gas flow rate exceeds the maximum established during the test conducted under § 60.5413a(d).

(ii) Failure of the monthly visible emissions test conducted under § 60.5413a(e)(3) occurs.

(h) For each control device used to comply with the emission reduction standard in § 60.5395a(a)(2) for your storage vessel affected facility, you must demonstrate continuous compliance according to paragraphs (h)(1) through (h)(4) of this section. You are exempt from the requirements of this paragraph if you install a control device model tested in accordance with § 60.5413a(d)(2) through (10), which meets the criteria in § 60.5413a(d)(11), the reporting requirement in § 60.5413a(d)(12), and meet the continuous compliance requirement in § 60.5413a(e).

(1) For each combustion device you must conduct inspections at least once every calendar month according to paragraphs (h)(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 of appendix A of this part. 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 the 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 (h)(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 in § 60.5420a(c)(13).

(4) Conduct a periodic performance test no later than 60 months after the initial performance test as specified in § 60.5413a(b)(5)(ii) and conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test.

§ 60.5420a What are my notification, reporting, and recordkeeping requirements?

(a) You must submit the notifications according to paragraphs (a)(1) and (2) of this section if you own or operate one or more of the affected facilities specified in § 60.5365a that was constructed, modified or reconstructed during the reporting period.

(1) If you own or operate an affected facility that is the group of all equipment within a process unit at an onshore natural gas processing plant, or a sweetening unit at an onshore natural gas processing plant, you must submit

the notifications required in § 60.7(a)(1), (3), and (4). If you own or operate a well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, or collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station, you are not required to submit the notifications required in § 60.7(a)(1), (3), and (4).

(2)(i) If you own or operate a well affected facility, you must submit a notification to the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the United States Well Number; the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. You may submit the notification in writing or in electronic format.

(ii) If you are subject to state regulations that require advance notification of well completions and you have met those notification requirements, then you are considered to have met the advance notification requirements of paragraph (a)(2)(i) of this section.

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (8) and (12) of this section and performance test reports as specified in paragraph (b)(9) or (10) of this section, if applicable. You must submit annual reports following the procedure specified in paragraph (b)(11) of this section. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to § 60.5410a. Subsequent annual reports are due no later than same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (8) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period.

(1) The general information specified in paragraphs (b)(1)(i) through (iv) of this section for all reports.

(i) The company name, facility site name associated with the affected facility, US Well ID or US Well ID associated with the affected facility, if applicable, and address of the affected facility. If an address is not available for the site, include a description of the site location and provide the latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) An identification of each affected facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(iv) 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.

(2) For each well affected facility, the information in paragraphs (b)(2)(i) through (iii) of this section.

(i) Records of each well completion operation as specified in paragraphs (c)(1)(i) through (iv) and (vi) of this section, if applicable, for each well affected facility conducted during the reporting period. In lieu of submitting the records specified in paragraph (c)(1)(i) through (iv) of this section, the owner or operator may submit a list of the well completions with hydraulic fracturing completed during the reporting period and the records required by paragraph (c)(1)(v) of this section for each well completion.

(ii) Records of deviations specified in paragraph (c)(1)(ii) of this section that occurred during the reporting period.

(iii) Records specified in paragraph (c)(1)(vii) of this section, if applicable, that support a determination under 60.5432a that the well affected facility is a low pressure well as defined in 60.5430a.

(3) For each centrifugal compressor affected facility, the information specified in paragraphs (b)(3)(i) through (iv) of this section.

(i) An identification of each centrifugal compressor using a wet seal system constructed, modified or reconstructed during the reporting period.

(ii) Records of deviations specified in paragraph (c)(2) of this section that occurred during the reporting period.

(iii) If required to comply with § 60.5380a(a)(2), the records specified in paragraphs (c)(6) through (11) of this section.

(iv) If complying with § 60.5380a(a)(1) with a control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and § 60.5413a(e), records specified in paragraph (c)(2)(i) through (c)(2)(vii) of this section for each centrifugal compressor using a wet seal system constructed, modified or reconstructed during the reporting period.

(4) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(4)(i) and (ii) of this section.

(i) The cumulative number of hours of operation or the number of months since initial startup 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 (c)(3)(iii) of this section that occurred during the reporting period.

(5) For each pneumatic controller affected facility, the information specified in paragraphs (b)(5)(i) through (iii) of this section.

(i) An identification of each pneumatic controller constructed, modified or reconstructed during the reporting period, including the identification information specified in § 60.5390a(b)(2) or (c)(2).

(ii) If applicable, documentation that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than 6 standard cubic feet per hour are required and the reasons why.

(iii) Records of deviations specified in paragraph (c)(4)(v) of this section that occurred during the reporting period.

(6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) through (vii) of this section.

(i) An identification, including the location, of each storage vessel affected facility for which construction, modification or reconstruction commenced during the reporting period. 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.

(ii) Documentation of the VOC emission rate determination according to § 60.5365a(e) for each storage vessel that became an affected facility during the reporting period or is returned to service during the reporting period.

(iii) Records of deviations specified in paragraph (c)(5)(iii) of this section that occurred during the reporting period.

(iv) A statement that you have met the requirements specified in § 60.5410a(h)(2) and (3).

(v) You must identify each storage vessel affected facility that is removed from service during the reporting period as specified in § 60.5395a(c)(1)(ii), including the date the storage vessel affected facility was removed from service.

(vi) You must identify each storage vessel affected facility returned to service during the reporting period as specified in § 60.5395a(c)(3), including the date the storage vessel affected facility was returned to service.

(vii) If complying with § 60.5395a(a)(2) with a control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and § 60.5413a(e), records specified in paragraphs (c)(5)(vi)(A) through (F) of this section for each storage vessel constructed, modified, reconstructed or returned to service during the reporting period.

(7) For the collection of fugitive emissions components at each well site and the collection of fugitive emissions components at each compressor station within the company-defined area, the records of each monitoring survey including the information specified in paragraphs (b)(7)(i) through (xii) of this section. For the collection of fugitive emissions components at a compressor station, if a monitoring survey is waived under § 60.5397a(g)(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.

(i) Date of the survey.

(ii) Beginning and end time of the survey.

(iii) 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.

(iv) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(v) Monitoring instrument used.

(vi) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(vii) Number and type of components for which fugitive emissions were detected.

(viii) Number and type of fugitive emissions components that were not repaired as required in § 60.5397a(h).

(ix) Number and type of difficult-to-monitor and unsafe-to-monitor fugitive emission components monitored.

(x) The date of successful repair of the fugitive emissions component.

(xi) Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair.

(xii) Type of instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

(8) For each pneumatic pump affected facility, the information specified in paragraphs (b)(8)(i) through (iii) of this section.

(i) For each pneumatic pump that is constructed, modified or reconstructed during the reporting period, you must provide certification that the pneumatic pump meets one of the conditions described in paragraphs (b)(8)(i)(A), (B) or (C) of this section.

(A) No control device or process is available on site.

(B) A control device or process is available on site and the owner or operator has determined in accordance with § 60.5393a(b)(5) that it is technically infeasible to capture and route the emissions to the control device or process.

(C) Emissions from the pneumatic pump are routed to a control device or process. If the control device is designed to achieve less than 95 percent emissions reduction, specify the percent emissions reductions the control device is designed to achieve.

(ii) For any pneumatic pump affected facility which has been previously reported as required under paragraph (b)(8)(i) of this section and for which a change in the reported condition has occurred during the reporting period, provide the identification of the pneumatic pump affected facility and the date it was previously reported and a certification that the pneumatic pump meets one of the conditions described in paragraphs (b)(8)(ii)(A), (B) or (C) or (D) of this section.

(A) A control device has been added to the location and the pneumatic pump now reports according to paragraph (b)(8)(i)(C) of this section.

(B) A control device has been added to the location and the pneumatic pump affected facility now reports according to paragraph (b)(8)(i)(B) of this section.

(C) A control device or process has been removed from the location or otherwise is no longer available and the pneumatic pump affected facility now report according to paragraph (b)(8)(i)(A) of this section.

(D) 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 § 60.5393a(b)(5) through an engineering evaluation that it is technically infeasible to capture and route the emissions to another control device or process.

(iii) Records of deviations specified in paragraph (c)(16)(ii) of this section that occurred during the reporting period.

(9) Within 60 days after the date of completing each performance test (see § 60.8) required by this subpart, except testing conducted by the manufacturer as specified in § 60.5413a(d), you must submit the results of the performance test following the procedure specified in either paragraph (b)(9)(i) or (ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (*https://www3.epa.gov/ttn/chief/ert/ert_info.html*) at the time of the test, you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Performance test data must be submitted in a file format generated through the use of the EPA's ERT or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, 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 U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in § 60.4.

(10) For combustion control devices tested by the manufacturer in accordance with § 60.5413a(d), an electronic copy of the performance test results required by § 60.5413a(d) 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/*.

(11) You must submit reports to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX (*https://cdx.epa.gov/)*.) You must use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (*https://www3.epa.gov/ttn/chief/cedri/*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in § 60.4. Once the form has been available in CEDRI for at least 90 calendar days, you must begin submitting all subsequent reports via CEDRI. The reports must be submitted by the deadlines specified in this subpart, regardless of the method in which the reports are submitted.

(12) You must submit the certification signed by the qualified professional engineer according to § 60.5411a(d) for each closed vent system routing to a control device or process.

(c) *Recordkeeping requirements.* You must maintain the records identified as specified in § 60.7(f) and in paragraphs (c)(1) through (16) of this section. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years. Any records required to be maintained by this subpart that are submitted electronically via the EPA's CDX may be maintained in electronic format.

(1) The records for each well affected facility as specified in paragraphs (c)(1)(i) through (vii) of this section, as applicable. For each well affected facility for which you make a claim that the well affected facility is not subject to the requirements for well completions pursuant to 60.5375a(g), you must maintain the record in paragraph (c)(1)(vi), only.

(i) Records identifying each well completion operation for each well affected facility;

(ii) Records of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in § 60.5375a.

(iii) Records required in § 60.5375a(b) or (f)(3) for each well completion operation conducted for each well affected facility that occurred during the reporting period. You must maintain the records specified in paragraphs (c)(1)(iii)(A) through (C) of this section.

(A) For each well affected facility required to comply with the requirements of § 60.5375a(a), you must record: The location of the well; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time of each attempt to direct flowback to a separator as required in § 60.5375a(a)(1)(ii); the date and time of each occurrence of returning to the initial flowback stage under § 60.5375a(a)(1)(i); and the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours. In addition, for wells where it is technically infeasible to route the recovered gas to any of the four options specified in § 60.5375a(a)(1)(ii), you must record the reasons for the claim of technical infeasibility with respect to all four options provided in that subparagraph, including but not limited to; name and location of the nearest gathering line and technical considerations preventing routing to this line; capture, reinjection, and reuse technologies considered and aspects of gas or equipment preventing use of recovered gas as a fuel onsite; and technical considerations preventing use of recovered gas for other useful purpose that that a purchased fuel or raw material would serve.

(B) For each well affected facility required to comply with the requirements of § 60.5375a(f), you must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record the duration of recovery to the flow line.

(C) For each well affected facility for which you make a claim that it meets the criteria of § 60.5375a(a)(1)(iii)(A), you must maintain the following:

(*1*) Records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record: The date and time of each attempt to direct flowback to a separator; the date and time of each occurrence of returning to the initial flowback stage; duration of recovery and disposition of recovery (*i.e.* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve.

(*2*) If applicable, records that the conditions of § 60.5375a(1)(iii)(A) are no longer met and that the well completion operation has been stopped and a separator installed. The records shall include the date and time the well completion operation was stopped and the date and time the separator was installed.

(*3*) A record of the claim signed by the certifying official that no liquids collection is at the well site. 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.

(iv) For each well affected facility for which you claim an exception under § 60.5375a(a)(3), you must record: The location of the well; the United States Well Number; the specific exception claimed; the starting date and ending date for the period the well operated under the exception; and an explanation of why the well meets the claimed exception.

(v) For each well affected facility required to comply with both § 60.5375a(a)(1) and (3), if you are using a digital photograph in lieu of the records required in paragraphs (c)(1)(i) through (iv) of this section, you must retain the records of the digital photograph as specified in § 60.5410a(a)(4).

(vi) For each well affected facility for which you make a claim that the well affected facility is not subject to the well completion standards according to 60.5375a(g), you must maintain:

(A) A record of the analysis that was performed in order the make that claim, including but not limited to, GOR values for established leases and data from wells in the same basin and field;

(B) The location of the well; the United States Well Number;

(C) A record of the claim 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.

(vii) For each well affected facility for which you determine according to § 60.5432a that it is a low pressure well, a record of the determination and supporting inputs and calculations.

(2) For each centrifugal compressor affected facility, you must maintain records of deviations in cases where the centrifugal compressor was not operated in compliance with the requirements specified in § 60.5380a. Except as specified in paragraph (c)(2)(vii) of this section, you must maintain the records in paragraphs (c)(2)(i) through (vi) of this section for each control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and § 60.5413a(e) and used to comply with § 60.5380a(a)(1) for each centrifugal compressor.

(i) Make, model and serial number of purchased device.

(ii) Date of purchase.

(iii) Copy of purchase order.

(iv) 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.

(v) Inlet gas flow rate.

(vi) Records of continuous compliance requirements in § 60.5413a(e) as specified in paragraphs (c)(2)(vi)(A) through (E) of this section.

(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 (c)(2)(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 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.

(3) For each reciprocating compressor affected facility, you must maintain the records in paragraphs (c)(3)(i) through (iii) of this section.

(i) Records of the cumulative number of hours of operation or number of months since initial startup or the previous replacement of the reciprocating compressor rod packing, 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 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 § 60.5385a(a)(3).

(iii) Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in § 60.5385a.

(4) For each pneumatic controller affected facility, you must maintain the records identified in paragraphs (c)(4)(i) through (v) of this section, as applicable.

(i) Records of the date, location and manufacturer specifications for each pneumatic controller constructed, modified or reconstructed.

(ii) Records of the demonstration that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than the applicable standard are required and the reasons why.

(iii) If the pneumatic controller is not located at a natural gas processing plant, records of the manufacturer's specifications indicating that the controller is designed such that natural gas bleed rate is less than or equal to 6 standard cubic feet per hour.

(iv) If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.

(v) Records of deviations in cases where the pneumatic controller was not operated in compliance with the requirements specified in § 60.5390a.

(5) For each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) through (vi) of this section.

(i) If required to reduce emissions by complying with § 60.5395a(a)(2), the records specified in §§ 60.5420a(c)(6) through (8), 60.5416a(c)(6)(ii), and 60.5416a(c)(7)(ii). You must maintain the records in paragraph (c)(5)(vi) of this part for each control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and § 60.5413a(e) and used to comply with § 60.5395a(a)(2) for each storage vessel.

(ii) Records of each VOC emissions determination for each storage vessel affected facility made under § 60.5365a(e) including identification of the model or calculation methodology used to calculate the VOC emission rate.

(iii) Records of deviations in cases where the storage vessel was not operated in compliance with the requirements specified in §§ 60.5395a, 60.5411a, 60.5412a, and 60.5413a, as applicable.

(iv) 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 the site 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, will be added to the count towards the number of consecutive days.

(v) You must maintain records of the identification and location of each storage vessel affected facility.

(vi) Except as specified in paragraph (c)(5)(vi)(G) of this section, you must maintain the records specified in paragraphs (c)(5)(vi)(A) through (F) of this section for each control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and § 60.5413a(e) and used to comply with § 60.5395a(a)(2) for each storage vessel.

(A) Make, model and serial number of purchased device.

(B) Date of purchase.

(C) Copy of purchase order.

(D) 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.

(E) Inlet gas flow rate.

(F) Records of continuous compliance requirements in § 60.5413a(e) as specified in paragraphs (c)(5)(vi)(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 (c)(5)(vi)(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 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.

(6) Records of each closed vent system inspection required under § 60.5416a(a)(1) and (2) for centrifugal compressors, reciprocating compressors and pneumatic pumps, or § 60.5416a(c)(1) for storage vessels.

(7) A record of each cover inspection required under § 60.5416a(a)(3) for centrifugal or reciprocating compressors or § 60.5416a(c)(2) for storage vessels.

(8) If you are subject to the bypass requirements of § 60.5416a(a)(4) for centrifugal compressors, reciprocating compressors or pneumatic pumps, or § 60.5416a(c)(3) for storage vessels, 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.

(9) If you are subject to the closed vent system no detectable emissions requirements of § 60.5416a(b) for centrifugal compressors, reciprocating compressors or pneumatic pumps, a record of the monitoring conducted in accordance with § 60.5416a(b).

(10) For each centrifugal compressor or pneumatic pump affected facility, records of the schedule for carbon replacement (as determined by the design analysis requirements of § 60.5413a(c)(2) or (3)) and records of each carbon replacement as specified in § 60.5412a(c)(1).

(11) For each centrifugal compressor affected facility subject to the control device requirements of § 60.5412a(a), (b), and (c), 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.

(12) For each carbon adsorber installed on storage vessel affected facilities, records of the schedule for carbon replacement (as determined by the design analysis requirements of § 60.5412a(d)(2)) and records of each carbon replacement as specified in § 60.5412a(c)(1).

(13) For each storage vessel affected facility subject to the control device requirements of § 60.5412a(c) and (d), you must maintain records of the inspections, including any corrective actions taken, the manufacturers' operating instructions, procedures and maintenance schedule as specified in § 60.5417a(h)(3). You must maintain records of EPA Method 22 of appendix A–7 of this part, section 11 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 of appendix A–7 of this part. Manufacturer's operating instructions, procedures and maintenance schedule must be available for inspection.

(14) A log of records as specified in § 60.5412a(d)(1)(iii), for all inspection, repair and maintenance activities for each control device failing the visible emissions test.

(15) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, the records identified in paragraphs (c)(15)(i) through (iii) of this section.

(i) The fugitive emissions monitoring plan as required in § 60.5397a(b), (c), and (d).

(ii) The records of each monitoring survey as specified in paragraphs (c)(15)(ii)(A) through (I) of this section.

(A) Date of the survey.

(B) Beginning and end time of the survey.

(C) Name of operator(s) performing survey. You must note the training and experience of the operator.

(D) Monitoring instrument used.

(E) 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 compressor 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.

(F) Fugitive emissions component identification when Method 21 is used to perform the monitoring survey.

(G) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(H) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(I) Documentation of each fugitive emission, including the information specified in paragraphs (c)(15)(ii)(I)(*1*) through (*12*) of this section.

(*1*) Location.

(*2*) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(*3*) Number and type of components for which fugitive emissions were detected.

(*4*) Number and type of difficult-to-monitor and unsafe-to-monitor fugitive emission components monitored.

(*5*) Instrument reading of each fugitive emissions component that requires repair when Method 21 is used for monitoring.

(*6*) Number and type of fugitive emissions components that were not repaired as required in § 60.5397a(h).

(*7*) 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 § 60.5397a(h)(3)(ii).

(*8*) 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 § 60.5397a(h)(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 (c)(15)(ii)(E) 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.

(*9*) Repair methods applied in each attempt to repair the fugitive emissions components.

(*10*) Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair.

(*11*) The date of successful repair of the fugitive emissions component.

(*12*) Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

(iii) For the collection of fugitive emissions components at a compressor station, if a monitoring survey is waived under § 60.5397a(g)(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.

(16) For each pneumatic pump affected facility, you must maintain the records identified in paragraphs (c)(16)(i) through (v) of this section.

(i) Records of the date, location and manufacturer specifications for each pneumatic pump constructed, modified or reconstructed.

(ii) Records of deviations in cases where the pneumatic pump was not operated in compliance with the requirements specified in § 60.5393a.

(iii) Records on the control device used for control of emissions from a pneumatic pump including the installation date, manufacturer's specifications, and if the control device is designed to achieve less than 95 percent emission reduction, a design evaluation or manufacturer's specifications indicating the percentage reduction achieved the control device is designed to achieve.

(iv) Records substantiating a claim according to § 60.5393a(b)(5) 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 § 60.5393a(b)(5)(ii)and the records of the engineering assessment of technical infeasibility performed according to § 60.5393a(b)(5)(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 implementing agency.

(17) For each closed vent system routing to a control device or process, the records of the assessment conducted according to § 60.5411a(d):

(i) A copy of the assessment conducted according to § 60.5411a(d)(1);

(ii) A copy of the certification according to § 60.5411a(d)(1)(i); and

(iii) 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 delegated authority.

§ 60.5421a What are my additional recordkeeping requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraph (b) of this section in addition to the requirements of § 60.486a.

(b) The following recordkeeping requirements apply to pressure relief devices subject to the requirements of § 60.5401a(b)(1).

(1) When each leak is detected as specified in § 60.5401a(b)(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.

(2) When each leak is detected as specified in § 60.5401a(b)(2), the information specified in paragraphs (b)(2)(i) through (x) of this section must 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.

(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) ''Above 500 ppm'' if the maximum instrument reading measured by the methods specified in § 60.5400a(d) after each repair attempt is 500 ppm or greater.

(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.

(x) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of § 60.482–4a(a). The designation of equipment subject to the provisions of § 60.482–4a(a) must be signed by the owner or operator.

§ 60.5422a What are my additional reporting requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of § 60.487a(a), (b), (c)(2)(i) through (iv), and (c)(2)(vii) through (viii). You must submit semiannual reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (*https://www3.epa.gov/ttn/chief/cedri/*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, submit the report to the Administrator at the appropriate address listed in § 60.4. Once the form has been available in CEDRI for at least 90 days, you must begin submitting all subsequent reports via CEDRI. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(b) An owner or operator must include the following information in the initial semiannual report in addition to the information required in § 60.487a(b)(1) through (4): Number of pressure relief devices subject to the requirements of § 60.5401a(b) except for those pressure relief devices designated for no detectable emissions under the provisions of § 60.482–4a(a) and those pressure relief devices complying with § 60.482–4a(c).

(c) An owner or operator must include the information specified in paragraphs (c)(1) and (2) of this section in all semiannual reports in addition to the information required in § 60.487a(c)(2)(i) through (vi):

(1) Number of pressure relief devices for which leaks were detected as required in § 60.5401a(b)(2); and

(2) Number of pressure relief devices for which leaks were not repaired as required in § 60.5401a(b)(3).

§ 60.5423a What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?

(a) You must retain records of the calculations and measurements required in § 60.5405a(a) and (b) and § 60.5407a(a) through (g) for at least 2 years following the date of the measurements. This requirement is included under § 60.7(f) of the General Provisions.

(b) You must submit a report of excess emissions to the Administrator in your annual report if you had excess emissions during the reporting period. The excess emissions report must be submitted to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) You must use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (*https://www3.epa.gov/ttn/chief/cedri/*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in § 60.4. Once the form has been available in CEDRI for at least 90 days, you must begin submitting all subsequent reports via CEDRI. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted. For the purpose of these reports, excess emissions are defined as specified in paragraphs (b)(1) and (2) of this section.

(1) Any 24-hour period (at consistent intervals) during which the average sulfur emission reduction efficiency (R) is less than the minimum required efficiency (Z).

(2) For any affected facility electing to comply with the provisions of § 60.5407a(b)(2), any 24-hour period during which the average temperature of the gases leaving the combustion zone of an incinerator is less than the appropriate operating temperature as determined during the most recent performance test in accordance with the provisions of § 60.5407a(b)(3). Each 24-hour period must consist of at least 96 temperature measurements equally spaced over the 24 hours.

(c) To certify that a facility is exempt from the control requirements of these standards, for each facility with a design capacity less than 2 LT/D of H2S in the acid gas (expressed as sulfur) you must keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of H_2S expressed as sulfur.

(d) If you elect to comply with § 60.5407a(e) you must keep, for the life of the facility, a record demonstrating that the facility's design capacity is less than 150 LT/D of H2S expressed as sulfur.

(e) The requirements of paragraph (b) of this section remain in force until and unless the EPA, in delegating enforcement authority to a state under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of obligation to comply with paragraph (b) of this section, provided that they comply with the requirements established by the state. Electronic reporting to the EPA cannot be waived, and as such, the provisions of this paragraph do not relieve owners or operators of affected facilities of the requirement to submit the electronic reports required in this section to the EPA.

§ 60.5425a What parts of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

§ 60.5430a What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VVa of part 60; and the following terms shall have the specific meanings given them.

Acid gas means a gas stream of hydrogen sulfide (H_2S) and carbon dioxide (CO_2) that has been separated from sour natural gas by a sweetening unit.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

API Gravity means the weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API) and is expressed in degrees.

Artificial lift equipment means mechanical pumps including, but not limited to, rod pumps and electric submersible pumps used to flowback fluids from a well.

Bleed rate means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a pneumatic controller.

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where:

(1) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$A = Y \times (B \div 100)$;

(2) The percent Y is determined from the following equation: $Y = 1.0 - 0.575 \log \times$, where $\times$ is 2011 minus the year of construction; and

(3) The applicable basic annual asset guideline repair allowance, B, is 4.5.

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 subpart.

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.

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.

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.

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 § 60.5397a.

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.

Continuous bleed means a continuous flow of pneumatic supply natural gas to a pneumatic controller.

Crude oil and natural gas source category means:

(1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and

(2) Natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station.

Custody transfer means the transfer of crude oil or 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.

Dehydrator means a device in which an absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber).

Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.

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.

Equipment, as used in the standards and requirements in this subpart relative to the equipment leaks of GHG (in the form of methane) and 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 subpart.

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.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Flow line means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

Flowback means the process of allowing fluids and entrained solids to flow from a well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The term flowback also means the fluids and entrained solids that emerge from a well during the flowback process. The flowback period begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage.

Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to § 60.5411a, thief hatches or other openings on a controlled storage vessel not subject to § 60.5395a, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

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.

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.

Greenfield site means a site, other than a natural gas processing plant, which is entirely new construction. Natural gas processing plants are not considered to be greenfield sites, even if they are entirely new construction.

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.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in § 60.485a(e) or § 60.5401a(f)(2).

In wet gas service means that a compressor or piece of equipment contains or contacts the field gas before the extraction step at a gas processing plant process unit.

Initial flowback stage means the period during a well completion operation which begins at the onset of flowback and ends at the separation flowback stage.

Intermediate hydrocarbon liquid means any naturally occurring, unrefined petroleum liquid.

Intermittent/snap-action pneumatic controller means a pneumatic controller that is designed to vent non-continuously.

Liquefied natural gas unit means a unit used to cool natural gas to the point at which it is condensed into a liquid which is colorless, odorless, non-corrosive and non-toxic.

Liquid collection system means tankage and/or lines at a well site to contain liquids from one or more wells or to convey liquids to another site.

Local distribution company (LDC) custody transfer station means a metering station where the LDC receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

Low pressure well means a well that satisfies at least one of the following conditions:

(1) The static pressure at the wellhead following fracturing but prior to the onset of flowback is less than the flow line pressure at the sales meter;

(2) The pressure of flowback fluid immediately before it enters the flow line, as determined under § 60.5432a, is less than the flow line pressure at the sales meter; or

(3) Flowback of the fracture fluids will not occur without the use of artificial lift equipment.

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-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 for purposes of this subpart. 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-driven pneumatic controller means a pneumatic controller powered by pressurized natural gas.

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).

Nonfractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

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.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

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.

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.

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.

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.

Recovered gas means gas recovered through the separation process during flowback.

Recovered liquids means any crude oil, condensate or produced water recovered through the separation process during flowback.

Reduced emissions completion means a well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.

Reduced sulfur compounds means H_2S, carbonyl sulfide (COS), and carbon disulfide (CS_2).

Removed from service means that a storage vessel affected facility has been physically isolated and disconnected from the process for a purpose other than maintenance in accordance with § 60.5395a(c)(1).

Returned to service means that a storage vessel affected facility that was removed from service has been:

(1) Reconnected to the original source of liquids or has been used to replace any storage vessel affected facility; or

(2) Installed in any location covered by this subpart 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.

Salable quality gas means natural gas that meets the flow line or collection system operator specifications, regardless of whether such gas is sold.

Separation flowback stage means the period during a well completion operation when it is technically feasible for a separator to function. The separation flowback stage ends either at the startup of production, or when the well is shut in and permanently disconnected from the flowback equipment.

Startup of production means the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water.

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 well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. 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 § 60.5395a(c)(1) until such time as such tank or other vessel has been returned to service. For the purposes of this subpart, 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 § 60.5420a(c)(5)(iv), 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. This exclusion does not apply to a well completion vessel as described above.

(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 and without emissions to the atmosphere.

Sulfur production rate means the rate of liquid sulfur accumulation from the sulfur recovery unit.

Sulfur recovery unit means a process device that recovers element sulfur from acid gas.

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.

Sweetening unit means a process device that removes hydrogen sulfide and/or carbon dioxide from the sour natural gas stream.

Total Reduced Sulfur (TRS) means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide as measured by Method 16 of appendix A–6 of this part.

Total SO_2 equivalents means the sum of volumetric or mass concentrations of the sulfur compounds obtained by adding the quantity existing as SO_2 to the quantity of SO_2 that would be obtained if all reduced sulfur compounds were converted to SO_2 (ppmv or kg/dscm (lb/dscf)).

Underground storage vessel means a storage vessel stored below ground.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Well completion means the process that allows for the flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank.

Well completion operation means any well completion with hydraulic fracturing or refracturing occurring at a well affected facility.

Well completion vessel means a vessel that contains flowback during a well completion operation following hydraulic fracturing or refracturing. A well completion vessel may be a lined earthen pit, a tank or other vessel that is skid-mounted or portable. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart.

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 § 60.5397a, 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.

Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.

§ 60.5432a How do I determine whether a well is a low pressure well using the low pressure well equation?

(a) To determine that your well is a low pressure well subject to § 60.5375a(f), you must determine whether the characteristics of the well are such that the well meets the definition of low pressure well in § 60.5430a. To determine that the well meets the definition of low pressure well in § 60.5430a, you must use the low pressure well equation below:

$$P_L\ (psia) = 0.495 \times P_R - \frac{q_g}{q_g+q_o+q_w}\left[0.05 \times P_R + 0.038 \times L - 67.578\right] - \left[\frac{q_o}{q_g+q_o+q_w} \times \frac{\rho_o}{144} + \frac{q_w}{q_g+q_o+q_w} 0.433\right] \cdot L$$

Where:

(1) P_L is the pressure of flowback fluid immediately before it enters the flow line, expressed in pounds force per square inch (psia), and is to be calculated using the equation above;

(2) P_R is the pressure of the reservoir containing oil, gas, and water at the well site, expressed in psia;

(3) $L$is the true vertical depth of the well, expressed in feet (ft);

(4) q_o is the flow rate of oil in the well, expressed in cubic feet/second (cu ft/sec);

(5) q_g is the flow rate of gas in the well, expressed in cu ft/sec;

(6) q_w is the flow rate of water in the well, expressed in cu ft/sec;

(7) ρ_o is the density of oil in the well, expressed in pounds mass per cubic feet (lbm/cu ft).

(b) You must determine the four values in paragraphs (a)(4) through (7) of this section, using the calculations in paragraphs (b)(1) through (b)(15) of this section.

(1) Determine the value of the bottom hole pressure, P_{BH} (*psia*), based on available information at the well site, or by calculating it using the reservoir pressure, P_R (*psia*), in the following equation:

$$P_{BH}\ (psia) = \frac{1}{2} P_R$$

(2) Determine the value of the bottom hole temperature, T_{BH} (*F*), based on available information at the well site, or by calculating it using the true vertical depth of the well, *L (ft)*, in the following equation:

$T_{BH}\ (F) = (0.014 \times L) + 79.081$

(3) Calculate the value of the applicable natural gas specific gravity that would result from a separator pressure of 100 psig, γ_{gs}, using the following equation with: Separator at standard conditions (pressure, p = 14.7 (*psia*), temperature, T = 60 (*F*)); the oil API gravity at the well site, γ_0; and the gas specific gravity at the separator under standard conditions, γ_{gp} = 0.75:

$$\gamma_{gs} = \gamma_{gp} \cdot \left(1.0 + 5.912\ x\ 10^{-5} \cdot \gamma_o \cdot T \cdot log\left(\frac{p}{114.7}\right)\right)$$

(4) Calculate the value of the applicable dissolved GOR, *Rs (scf/STBO)*, using the following equation with: The bottom hole pressure, P_{BH} (*psia*), determined in (b)(1) of this section; the bottom hole temperature, T_{BH} (*F*), determined in (b)(2) of this section; the gas gravity at separator pressure of 100 psig, γ_{gs}, calculated in (b)(3) of this section; the oil API gravity, γ_o, at the well site; and the constants, C1, C2, and C3, found in Table A:

$$R_s(\frac{scf}{STBO}) = C1 \cdot \gamma_{gs} \cdot {P_{BH}}^{C2} \cdot exp\left[C3\left(\frac{\gamma_o}{T_{BH}\ +\ 460}\right)\right]$$

TABLE A—COEFFICIENTS FOR THE CORRELATION FOR R_s

Constant	$\gamma_{API} \leq 30$	$\gamma_{API} > 30$
C1	0.0362	0.0178
C2	1.0937	1.1870
C3	25.7240	23.931

(5) Calculate the value of the oil formation volume factor, *Bo (bbl/STBO)*, using the following equation with: the bottom hole temperature, T_{BH} (*F*), determined in paragraph (b)(2) of this section; the gas gravity at separator pressure of 100 psig, γ_{gs}, calculated in paragraph (b)(3) of this section; the dissolved GOR, Rs (scf/STBO), calculated in paragraph (b)(4) of this section; the oil API gravity, γo, at the well site; and the constants, C1, C2, and C3, found in Table B:

$$B_o\left(\frac{bbl}{STBO}\right) = 1.0 + C1 \cdot R_s + (T_{BH} - 60)\left(\frac{\gamma_o}{\gamma_{gs}}\right) \cdot (C2 + C3 \cdot R_s)$$

TABLE B—COEFFICIENTS FOR THE CORRELATION FOR B_o

Constant	$\gamma_{API} \leq 30$	$\gamma_{API} > 30$
C1	4.677×10^{-4}	4.670×10^{-4}
C2	1.751×10^{-5}	1.100×10^{-5}
C3	-1.811×10^{-8}	1.337×10^{-9}

(6) Calculate the density of oil at the wellhead, $\rho_{WH}\,(\frac{lbm}{cu\,ft})$, using the following equation with the value of the oil API gravity, γ_o, at the well site:

$$\rho_{WH}\,(\frac{lbm}{cu\,ft}) = \frac{141.5}{\gamma_o + 131.5} \times 62.4$$

(7) Calculate the density of oil at bottom hole conditions, $\rho_{BH}\,(\frac{lbm}{cu\,ft})$, using the following equation with: the dissolved GOR, Rs (scf/STBO), calculated in paragraph (b)(4) of this section; the oil formation volume factor, Bo (bbl/STBO), calculated in paragraph (b)(5) of this section; the oil density at the wellhead, $\rho_{WH}\,(\frac{lbm}{cu\,ft})$, calculated in paragraph (b)(6) of this section; and the dissolved gas gravity, $\gamma_{gd} = 0.77$:

$$\rho_{BH}\,(\frac{lbm}{cu\,ft}) = \frac{\rho_{WH} + 0.0136 \times Rs \times \gamma_{gd}}{Bo}$$

(8) Calculate the density of oil in the well, $\rho_o\,(\frac{lbm}{cu\,ft})$, using the following equation with the density of oil at the wellhead, $\rho_{WH}\,(\frac{lbm}{cu\,ft})$, calculated in paragraph (b)(6) of this section; and the density of oil at bottom hole conditions, $\rho_{BH}\,(\frac{lbm}{cu\,ft})$, calculated in paragraph (b)(7) of this section:

$$\rho_o\left(\frac{lbm}{cu\,ft}\right) = 0.5 \times (\rho_{WH} + \rho_{BH})$$

(9) Calculate the oil flow rate, $q_o\,(cu\,ft/sec)$, using the following equation with: the oil formation volume factor, *Bo* (bbl/STBO), as calculated in paragraph (b)(5) of this section; and the estimated oil production rate at the well head, *Qo* (STBO/day):

$$q_o\left(\frac{cu\,ft}{sec}\right) = \text{Qo}\left(\frac{\text{STBO}}{\text{day}}\right) \times \text{Bo}\left(\frac{\text{bbl}}{\text{STBO}}\right) \times 5.614\left(\frac{\text{cu ft}}{\text{bbl}}\right) \times \frac{1}{24 \times 60 \times 60}\left(\frac{day}{sec}\right)$$

(10) Calculate the critical pressure, P_c (psia), and critical temperature, T_c (R), using the equations below with: Gas gravity at standard conditions (pressure, P = 14.7 (*psia*), temperature, T = 60 (*F*)), γ = 0.75; and where the mole fractions of nitrogen, carbon dioxide and hydrogen sulfide in the gas are X_{N_2} = 0.168225, X_{CO_2} = 0.013163, and X_{H_2S} = 0.013680, respectively:

$$P_c(psia) = 678 - 50 \cdot (\gamma_g - 0.5) - 206.7 \cdot X_{N_2} + 440 \cdot X_{CO_2} + 606.7 \cdot X_{H_2S}$$

$$T_c(R) = 326 + 315.7 \cdot (\gamma_g - 0.5) - 240 \cdot X_{N_2} - 88.3 \cdot XCO_2 + 133.3 \cdot X_{H_2S}$$

(11) Calculate reduced pressure, P_r, and reduced temperature, T_r, using the following equations with: the bottom hole pressure, P_{BH}, as determined in paragraph (b)(1) of this section; the bottom hole temperature, T_{BH} (*F*), as determined in paragraph (b)(2) of this section in the following equations:

$$P_r = \frac{P_{BH}}{P_c}$$

$$T_r = \frac{T_{BH} + 460}{T_c}$$

(12)(i) Calculate the gas compressibility factor, *Z*, using the following equation with the reduced pressure, P_r, calculated in paragraph (b)(11) of this section:

$$z = A + \frac{(1-A)}{e^B} + C \cdot p_r^D$$

(ii) The values for A, B, C, D in the above equation, are calculated using the following equations with the reduced pressure, P_r, and reduced temperature, T_r, calculated in paragraph (b)(11) of this section:

$$A = 1.39 \cdot (T_r - 0.92)^{0.5} - 0.36 * T_r - 0.101$$

$$B = (0.62 - 0.23 \cdot T_r) \cdot P_r + \left(\frac{0.066}{(T_r - 0.86)} - 0.037\right) \cdot P_r^2 + \frac{0.32}{10^{9 \cdot (T_r - 1)}} \cdot P_r^6$$

$$C = (0.132 - 0.32 \cdot \log(T_r))$$

$$D = 10^{0.3106 - 0.49 \cdot T_r + 0.1824 \cdot T_r^2}$$

(13) Calculate the gas formation volume factor, $B_g\left(\frac{cuft}{scf}\right)$, using the bottom hole pressure, $P_{BH}\,(psia)$, as determined in paragraph (b)(1) of this section; and the bottom hole temperature, $T_{BH}\,(F)$, as determined in paragraph (b)(2) of this section:

$$B_g\left(\frac{cuft}{scf}\right) = 0.0283 \cdot \frac{Z \cdot (T_{BH} + 460)}{P_{BH}} ()$$

(14) Calculate the gas flow rate, $q_g\left(\frac{cu\,ft}{sec}\right)$, using the following equation with: the value of gas formation volume factor, $B_g\left(\frac{cuft}{scf}\right)$, calculated in paragraph (b)(13) of this section; the estimated gas production rate, Qg (scf/day); the estimated oil production rate, Qo (STBO/day); and the dissolved GOR, Rs (scf/STBO), as calculated in paragraph (b)(4) of this section:

$$q_g\left(\frac{cf}{sec}\right) = (Q_g - R_s \cdot Q_o) \cdot B_g \cdot \frac{1}{24x60x60}$$

(15) Calculate the flow rate of water in the well, q_w (*cu ft/sec*), using the following equation with the water production rate Qw (bbl/day) at the well site:

$$q_w\left(\frac{cf}{sec}\right) = \mathrm{Qw}\left(\frac{\mathrm{bbl}}{\mathrm{day}}\right) \times 5.614\left(\frac{\mathrm{cf}}{\mathrm{bbl}}\right) \times \frac{1}{24 \times 60 \times 60}\left(\frac{day}{sec}\right)$$

§§ 60.5433a–60.5499a [Reserved]

TABLE 1 TO SUBPART OOOOa OF PART 60—REQUIRED MINIMUM INITIAL SO_2 EMISSION REDUCTION EFFICIENCY (Z_i)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	2.0 < X < 5.0	5.0 < X < 15.0	15.0 < X < 300.0	X > 300.0
Y > 50	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 99.9, whichever is smaller.		
20 < Y < 50	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 97.9, whichever is smaller		97.9
10 < Y < 20	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 93.5, whichever is smaller.	93.5	93.5
Y < 10	79.0	79.0	79.0	79.0

TABLE 2 TO SUBPART OOOOa OF PART 60—REQUIRED MINIMUM SO_2 EMISSION REDUCTION EFFICIENCY (Z_c)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	2.0 < X < 5.0	5.0 < X < 15.0	15.0 < X < 300.0	X > 300.0
Y > 50	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 99.9, whichever is smaller.		
20 < Y < 50	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 97.5, whichever is smaller		97.5
10 < Y < 20	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 90.8, whichever is smaller.	90.8	90.8
Y < 10	74.0	74.0	74.0	74.0

X = The sulfur feed rate from the sweetening unit (*i.e.*, the H_2S in the acid gas), expressed as sulfur, Mg/D(LT/D), rounded to one decimal place.

Y = The sulfur content of the acid gas from the sweetening unit, expressed as mole percent H_2S (dry basis) rounded to one decimal place.

Z = The minimum required sulfur dioxide (SO_2) emission reduction efficiency, expressed as percent carried to one decimal place. Z_i refers to the reduction efficiency required at the initial performance test. Z_c refers to the reduction efficiency required on a continuous basis after compliance with Z_i has been demonstrated.

As stated in § 60.5425a, you must comply with the following applicable General Provisions:

TABLE 3 TO SUBPART OOOOa OF PART 60—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART OOOOa

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.1	General applicability of the General Provisions	Yes	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5430a.
§ 60.3	Units and abbreviations	Yes	
§ 60.4	Address	Yes	
§ 60.5	Determination of construction or modification	Yes	
§ 60.6	Review of plans	Yes	
§ 60.7	Notification and record keeping	Yes	Except that § 60.7 only applies as specified in § 60.5420a(a).
§ 60.8	Performance tests	Yes	Performance testing is required for control devices used on storage vessels, centrifugal compressors and pneumatic pumps.
§ 60.9	Availability of information	Yes	
§ 60.10	State authority	Yes	
§ 60.11	Compliance with standards and maintenance requirements.	No	Requirements are specified in subpart OOOOa.
§ 60.12	Circumvention	Yes	
§ 60.13	Monitoring requirements	Yes	Continuous monitors are required for storage vessels.
§ 60.14	Modification	Yes	To the extent any provision in § 60.14 conflicts with specific provisions in subpart OOOOa, it is superseded by subpart OOOOa provisions.
§ 60.15	Reconstruction	Yes	Except that § 60.15(d) does not apply to wells, pneumatic controllers, pneumatic pumps, centrifugal compressors, reciprocating compressors or storage vessels.
§ 60.16	Priority list	Yes	
§ 60.17	Incorporations by reference	Yes	
§ 60.18	General control device and work practice requirements.	Yes	

TABLE 3 TO SUBPART OOOOa OF PART 60—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART OOOOa—Continued

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.19	General notification and reporting requirement	Yes	

[FR Doc. 2016–11971 Filed 6–2–16; 8:45 am]

BILLING CODE 6560–50–P