ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2010–0505, FRL–9791–9]

RIN 2060–AR75

Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule; notice of public hearing.

SUMMARY: On August 16, 2012, the EPA published final new source performance standards for the oil and natural gas sector. The Administrator received petitions for reconsideration of certain aspects of the standards. In this notice, the EPA is announcing proposed amendments as a result of reconsideration of certain issues related to implementation of storage vessel provisions. The proposed amendments also correct technical errors that were inadvertently included in the final rule.

DATES: *Comments.* Comments must be received on or before May 13, 2013, unless a public hearing is requested by April 17, 2013. If a hearing is requested on this proposed rule, written comments must be received by May 28, 2013.

Public Hearing. If anyone contacts the EPA requesting a public hearing by April 17, 2013 we will hold a public hearing on April 29, 2013.

Public Hearing. If a public hearing is requested by April 17, 2013, it will be held on April 29, 2013 at the EPA's Research Triangle Park Campus, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. The hearing will convene at 10:00 a.m. (Eastern Standard Time) and end at 5:00 p.m. (Eastern Standard Time). A lunch break will be held from 12:00 p.m. (Eastern Standard Time) until 1:00 p.m. (Eastern Standard Time). Please contact Joan C. Rogers at (919) 541–4487, or at *rogers.joanc@epa.gov* to request a hearing, to determine if a hearing will be held and to register to speak at the hearing, if one is held. If a hearing is requested, the last day to pre-register in advance to speak at the hearing will be April 25, 2013. Additionally, requests to speak will be taken the day of the hearing at the hearing registration desk, although preferences on speaking times may not be able to be fulfilled. If you require the service of a translator or special accommodations such as audio description, please let us know at the time of registration. If no one contacts the EPA requesting a public hearing to be held concerning this proposed rule by April 17, 2013, a public hearing will not take place.

If a hearing is held, it will provide interested parties the opportunity to present data, views or arguments concerning the proposed action. The EPA will make every effort to accommodate all speakers who arrive and register. Because this hearing, if held, will be at a U.S. governmental facility, individuals planning to attend the hearing should be prepared to show valid picture identification to the security staff in order to gain access to the meeting room. In addition, you will need to obtain a property pass for any personal belongings you bring with you. Upon leaving the building, you will be required to return this property pass to the security desk. No large signs will be allowed in the building, cameras may only be used outside of the building and demonstrations will not be allowed on federal property for security reasons. The EPA may ask clarifying questions during the oral presentations but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral comments and supporting information presented at the public hearing. If a hearing is held on April 29, 2013, written comments on the proposed rule must be postmarked by May 28, 2013. Commenters should notify Ms. Rogers if they will need specific equipment, or if there are other special needs related to providing comments at the hearing. The EPA will provide equipment for commenters to show overhead slides or make computerized slide presentations if we receive special requests in advance. Oral testimony will be limited to 5 minutes for each commenter. The EPA encourages commenters to provide the EPA with a copy of their oral testimony electronically (via email or CD) or in hard copy form. Verbatim transcripts of the hearings and written statements will be included in the docket for the rulemaking. The EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearing to run either ahead of schedule or behind schedule. Information regarding the hearing (including information as to whether or not one will be held) will be available at: *http://www.epa.gov/airquality/oilandgas/actions.html.* Again, all requests for a public hearing to be held must be received by April 17, 2013.

ADDRESSES: Submit your comments, identified by Docket ID Number EPA–HQ–OAR–2010–0505, by one of the following methods:

• *http://www.regulations.gov.* Follow the online instructions for submitting comments.

• *Email:* Comments may be sent by electronic mail (email) to *a-and-r-docket@epa.gov,* Attention Docket ID Number EPA–HQ–OAR–2010–0505.

• *Fax:* Fax your comments to: (202) 566–1741, Attention Docket ID Number EPA–HQ–OAR–2010–0505.

• *Mail:* Send your comments on this action to: EPA Docket Center (EPA/DC), Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Ave. NW., Washington, DC 20460, Docket ID Number EPA–HQ–OAR–2010–0505. Please include a total of two copies. The EPA requests a separate copy also be sent to the contact person identified below (see **FOR FURTHER INFORMATION CONTACT**).

• *Hand Delivery or Courier*: Deliver your comments to: EPA Docket Center, EPA West, Room 3334, 1301 Constitution Ave. NW., Washington, DC 20460. Please include a total of two copies. Such deliveries are only accepted during the Docket's normal hours of operation (8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays), and special arrangements should be made for deliveries of boxed information.

Instructions: All submissions must include agency name and respective docket number or Regulatory Information Number (RIN) for this rulemaking. All comments will be posted without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be confidential business information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or email. The *http://www.regulations.gov* Web site is an ''anonymous access'' system, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through *http://www.regulations.gov,* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption and be free of any defects or viruses.

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at the EPA's Docket Center, Public Reading Room, EPA West Building, Room Number 3334, 1301 Constitution Avenue NW., Washington, DC 20004. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION 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 organized as follows:

I. Preamble Acronyms and Abbreviations
II. General Information
A. Does this reconsideration notice apply to me?
B. What should I consider as I prepare my comments to the EPA?
C. How do I obtain a copy of this document and other related information?
III. Background
IV. Today's Action
V. Executive Summary
VI. Discussion of Provisions Subject to Reconsideration
A. Storage Vessels Implementation
B. Periodic Monitoring and Testing of Closed-Vent Systems and Control Devices
C. Test Protocol for Combustion Control Devices
D. Annual Report and Compliance Certification
E. Properly Designed Storage Vessels, Closed-Vent Systems and Control Devices
VII. Technical Corrections and Clarifications
VIII. Impacts of This Proposed Rule
A. What are the air impacts?
B. What are the energy impacts?
C. What are the compliance costs?
D. What are the economic and employment impacts?
E. What are the benefits of the proposed standards?
IX. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review
B. Paperwork Reduction Act
C. Regulatory Flexibility Act
D. Unfunded Mandates Reform Act of 1995
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks
H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

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
BOE Barrels of Oil Equivalent
bbl Barrel
bpd Barrels Per Day
BID Background Information Document
BSER Best System of Emissions Reduction
CAA Clean Air Act
CFR Code of Federal Regulations
CPMS Continuous Parametric Monitoring Systems
EIA Energy Information Administration
EPA Environmental Protection Agency
GOR Gas to Oil Ratio
HAP Hazardous Air Pollutant
HPDI HPDI, LLC
Mcf Thousand Cubic Feet
NTTAA National Technology Transfer and Advancement Act of 1995
NEI National Emissions Inventory
NEMS National Energy Modeling System
NESHAP National Emissions Standards for Hazardous Air Pollutants
NSPS New Source Performance Standards
OAQPS Office of Air Quality Planning and Standards
OMB Office of Management and Budget
OVA Olfactory, Visual and Auditory
PRA Paperwork Reduction Act
PTE Potential to Emit
RFA Regulatory Flexibility Act
SISNOSE Significant Economic Impact on a Substantial Number of Small Entities
tpy Tons per Year
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. Does this reconsideration notice apply to me?

Categories and entities potentially affected by today's notice include:

TABLE 1—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 is meant to provide a guide for readers regarding entities likely to be affected by this action. If you have any questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative as listed in 40 CFR 60.4 or 40 CFR 63.13 (General Provisions).

B. What should I consider as I prepare my comments to the EPA?

We seek comment only on the aspects of the final new source performance standards for the oil and natural gas sector specifically identified in this notice. We are not opening for reconsideration any other provisions of the new source performance standards at this time.

Do not submit information containing CBI to the EPA through *http://www.regulations.gov* or email. Send or deliver information identified as CBI only to the following address: Roberto Morales, OAQPS Document Control Officer (C404–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention: Docket ID Number EPA–HQ–OAR–2010–0505. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD–ROM that you mail to the EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

C. How do I obtain a copy of this document and other related information?

In addition to being available in the docket, electronic copies of these proposed rules will be available on the Worldwide Web through the TTN. Following signature, a copy of each proposed rule will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at the following address: *http://www.epa.gov/ttn/oarpg/.* The TTN provides information and technology exchange in various areas of air pollution control.

III. Background

The Administrator signed the Oil and Natural Gas Sector NSPS (40 CFR part 60 subpart OOOO) on April 17, 2012, and the final rule was published in the **Federal Register** at 77 FR 49490, August 16, 2012. Following promulgation of the final rule, the Administrator received petitions for reconsideration of several provisions of the NSPS pursuant to CAA section 307(d)(7)(B). Copies of the petitions are provided in rulemaking docket EPA–HQ–OAR–2010–0505.

IV. Today's Action

Today, we are granting reconsideration of, proposing and requesting comment on the following limited set of issues raised in the petitions described above: (1) Implementation date for the storage vessel provisions; (2) definition of ''storage vessel''; (3) definition of ''storage vessel affected facility'' for applicability purposes; (4) requirements for storage vessels constructed, modified or reconstructed during the period from the NSPS proposal date, August 23, 2011, to April 12, 2013; (5) an alternative mass-based standard for storage vessels after extended periods of low uncontrolled emissions; (6) compliance demonstration and monitoring provisions for closed-vent systems and control devices for storage vessels; (7) revised and clarified protocol for manufacturer testing of enclosed combustors; (8) broadening of the provision for determining VOC emissions and installing controls from only those affected storage vessels in certain locations to all affected storage vessels regardless of location; and (9) time period allowed for submittal of annual reports and compliance certifications. Finally, we are proposing to correct technical errors that were inadvertently included in the final rule.

This notice is limited to the specific issues identified in this notice. We will not respond to any comments addressing any other provisions of the oil and natural gas sector NSPS. We will address other issues for which we intend to grant reconsideration at a later time.

The impacts of today's proposed revisions on the costs and the benefits of the final rule are minor but cost-saving. We expect that affected facility owners and operators will install and operate the same or similar control technologies to meet the proposed revised standards in this notice as they would have chosen to comply with the standards in the August 2012 final rule, and revisions to the rule will not significantly increase emissions.

V. Executive Summary

The purpose of this action is to propose amendments to 40 CFR part 60, subpart OOOO, Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution. This proposal was developed to address certain issues primarily related to implementation of storage vessel provisions that have been raised by different stakeholders through several administrative petitions for reconsideration of the 2012 NSPS. The EPA is proposing to amend the NSPS to address these issues.

Information the EPA had during development of the final rule led to underestimation of the number of affected storage vessels. In response to information presented in some of the petitions for reconsideration, we have revised the estimated number of storage vessels subject to, and impacted by, the final NSPS. Based on the increased number of storage vessels we now estimate will be impacted by the proposed rule, it is clear that more time will be needed for a sufficient number of control devices to become available for the impacted storage vessels.

Based on our analysis and the information provided to us, we believe that there are on the order of 970 storage vessels per month being installed at this time and expected in the future, and over 20,000 affected storage vessels constructed, modified or reconstructed between the August 23, 2011, proposal date of the NSPS and April 12, 2013. For ease of reference in this notice, we refer to affected storage vessels constructed, modified or reconstructed between the August 23, 2011, proposal date of the NSPS and April 12, 2013 as ''Group 1'' and the cohort of storage vessels constructed, modified or reconstructed after April 12, 2013 as ''Group 2.'' Further, based on information available to us, there will not be a sufficient supply of control devices until 2016. To avoid postponing control for all affected storage vessels until 2016, we are proposing alternative measures for Group 1 affected sources, because many of these sources will likely have experienced significant emissions decline during this period. For Group 2 affected sources, we are proposing an April 15, 2014, compliance date for implementing the control requirements. For Group 1, instead of installation of a control device by April 15, 2014, we are proposing to require initial notification by October 15, 2013, to inform regulatory agencies of the existence and location of the vessels. We are also proposing that affected storage vessels in Group 1 that undergo an event after April 12, 2013 that leads to an increase in emissions, even without a physical change or change in the method of operation, implement the same control requirements as Group 2.

For storage vessels that have installed controls to meet the 95 percent VOC reduction standard, we are proposing streamlined compliance monitoring provisions that would be in place during our reconsideration of certain issues raised in the reconsideration petitions relative to the current compliance demonstration and monitoring requirements. We are proposing these streamlined provisions to provide assurance of compliance during the reconsideration period, while allowing the EPA time to consider fully the issues raised by petitioners concerning initial and continuous compliance provisions of the final NSPS. These compliance monitoring provisions include inspections performed at least monthly of covers, closed-vent systems and control devices. These procedures were selected to provide frequent checks that will lead to prompt repairs, to be performed by personnel already at the site and would require little or no specialized compliance monitoring training or equipment.

We are also proposing that the storage vessel standards include a sustained uncontrolled VOC emission rate of less than 4 tpy as an alternative emission limit to the 95 percent control in the final NSPS under specified circumstances. Specifically, the proposed alternative emission limit would be available to those who can demonstrate, based on records for the 12 months immediately preceding the demonstration and while the control is on, that its uncontrolled emissions during that 12 month-period would have been below 4 tpy. More detailed discussion of the less than 4 tpy emission limit is presented in section VI.A.4. We believe this alternate standard reflects the decline in production that all wells experience over time and allows control devices to be reused at other locations, which would help alleviate control device supply shortages. If, however, emissions subsequently increase above the 4 tpy limit, the sources would need to comply with the 95 percent control requirement as discussed in detail in section VI.4.

We are proposing to amend the definition of ''storage vessel'' to clarify that it refers only to vessels containing crude oil, condensate, intermediate hydrocarbon liquids or produced water. We believe this amendment addresses concerns raised by several petitioners that the definition in the final NSPS was overly broad and encompassed a number of unintended vessels, such as fuel tanks.

We are also proposing to amend the definition of ''storage vessel affected facility'' to include the 6 tpy VOC emission threshold. Without this threshold, the affected facility definition could impose unnecessary burden on operators of storage vessels that are not required to reduce emissions. In addition, we are proposing to clarify that a source can take into account any legal and practically enforceable emission limit under federal, state or local authority when determining the VOC emission rate for purposes of this threshold (i.e., they would not be subject to the storage vessel provisions of the NSPS if their potential to emit VOC was required to be less than 6 tpy under such limitation and in fact was).

We are proposing to revise the combustor control device manufacturer test protocol in the NSPS to align it with a similar protocol in the Oil and Natural Gas NESHAP (40 CFR 63, subpart HH). Our intent in the final NSPS was to make the NSPS and NESHAP protocols consistent. In addition, we are soliciting comment on a potential compliance approach based on the use of these manufacturer-tested combustor models. This potential compliance approach takes advantage of an opportunity to reduce the compliance burden on the affected facility. A discussion of this concept as it relates to this rule is presented in section VI.C of this preamble.

We are proposing to clarify that a storage vessel affected facility whose VOC emissions decrease to less than the threshold of 6 tpy would remain an affected facility. We believe this amendment is necessary to clarify that a storage vessel complying with the proposed alternative emission limit of less than 4 tpy would remain an affected facility and would be required to meet the 95 percent reduction standard should its uncontrolled emissions increase to 4 tpy or above in the future.

The final NSPS requires the annual report and compliance certification to be submitted within 30 days after the end of the compliance period. Several petitioners stated that because the annual report requires signature by a responsible official to certify the truth, accuracy and completeness of the report, 30 days is insufficient to compile all the required information and to obtain the signature of a senior company official. Therefore, we are proposing to allow 90 days after the end of the compliance period for submittal of the annual report and compliance certification. We are also proposing to make several clarifications and technical edits to the final NSPS.

In addition to the proposed revisions to the requirements discussed above, we present a discussion in section VI.E concerning the importance of proper design, sizing and operation of storage vessel affected facilities, their closed-vent systems and associated control devices. Improper design or operation of a storage vessel and its control system can result in occurrences where peak flow overwhelms the storage vessel and its capture systems, resulting in emissions that do not reach the control device.

VI. Discussion of Provisions Subject to Reconsideration

As summarized above, the EPA is proposing to address a number of issues that have been raised by different stakeholders through several administrative petitions for reconsideration of the final NSPS. The following sections present the issues raised by the petitioners that the EPA is addressing in this action and how the EPA proposes to resolve the issues. We also provide below a discussion of the EPA's expectations that operators will employ proper design, sizing and operation of storage vessel affected facilities, their closed-vent systems and their associated control devices.

A. Storage Vessels Implementation

1. Emission Standards for Storage Vessels

In their petitions for reconsideration, two petitioners stated that the EPA had significantly underestimated the number of storage vessels subject to and impacted by the NSPS. The petitioners pointed out that the EPA had based its analysis to predict the number of storage vessels that would be subject to and impacted by the final rules on storage vessels that were located at existing low producing wells. They reasoned that storage vessels at low producing wells were likely to have low throughput with corresponding low rates of flash emissions. Petitioners asserted that they estimated the number of affected storage vessels to be approximately 28,000 per year. They stated that, because their estimate was much higher than the 304 storage vessels per year the EPA had estimated, the 1-year phase in for the storage vessel requirements provided in the final rule was insufficient time for an adequate number of control devices to become available to meet demand. The petitioners suggested remedies that could help alleviate the shortage of control devices necessary to control the much greater number of storage vessels than the EPA had estimated: (1) Provide a greater period of time for phase in (i.e., 3 years instead of the 1 year provided in the final rule); and (2) allow removal of control devices after an extended period of low uncontrolled emissions. The first suggestion is addressed below in this section; the second is addressed in section VI.A.4.

In light of petitioners' assertions, we revisited our estimate of the number of storage vessels subject to the final NSPS. Our existing estimate was based on information reported in the NEI that had been used to develop the storage vessels provisions of NESHAP subpart HH several years ago. These data, combined with model plant information and modeled using over 100 tank datasets provided as part of API E&P TANKS, were used to develop an estimate of storage vessels expected to have VOC emissions of at least 6 tpy, the applicability threshold for storage vessels in the NSPS final rule.

In our original estimate, we used the throughput distribution of crude oil and condensate storage vessels as reported in the BID for NESHAP subpart HH to estimate the number of storage vessels in each of several throughput categories. This distribution was important because it was directly related to how we estimated VOC emissions from the tanks. We now know that the BID data were highly biased towards lower throughput tanks, which typically have lower emissions. We realize that, because of the high production rates of hydraulically fractured wells (the predominant type of wells today and expected to be the predominant type of wells in the future), the liquid throughput and resulting flash emissions for future storage vessels are much higher than for the storage vessels represented by the BID data. Thus, we now realize that the vast majority of the tanks, according to the BID distribution, were lower throughput tanks with VOC emissions less than 6 tpy, while a much higher number of future storage vessels are expected to have emissions of 6 tpy or more. Further, we now realize that historical trends we have used in the past to project industry growth are not applicable to the oil and natural gas sector going forward. This also contributed to our underestimate of affected storage vessels in the final rule analysis. In summary, the much higher production wells and correspondingly higher storage vessel emissions, combined with the great increase in the number of wells and associated storage vessels, resulted in the number of affected storage vessels to be greatly underestimated.

Based on the information from the petitioners, our re-evaluation of our dataset, and additional information described below, we revised our estimate of the number of storage vessels subject to the final NSPS. We estimated the number of new storage vessels predicted to be installed by assuming that there would be one storage vessel associated with each completed well. We understand that there may be more than one storage vessel associated with each well, but because the majority of VOC emissions from storage vessels occur due to flashing from the first storage vessel after the separator (where the pressure differential between devices is the greatest), other storage vessels would have comparatively lower emissions. Further, if more than one storage vessel does exist at the well site, it is likely that owners and operators would manifold these storage vessels together and route them to a single control device or VRU.

We recognize that an additional source of uncertainty in our revised analysis is that we are not able to estimate the number of wells on multi-well pads. We believe that these multi-well pads would be more likely to take advantage of the proximity of available storage vessel capacity, resulting in more than one well being associated with a storage vessel or group of storage vessels.

For the reasons stated above, we believe that our assumption of one storage vessel per well provides a reasonable basis for estimating the number of affected storage vessels since August 23, 2011, (the date the NSPS was proposed) and for future years. We drew estimates and predictions of the number of completed wells from 2011 to 2015 from the EIA NEMS 2012 forecasting model, a modeling platform consistent with the 2012 Annual Energy Outlook reference case.

To estimate the number of storage vessels that would be associated with wells of various production ranges, we used well-level production information from 2009 contained in the HPDI database to distribute the predicted number of well completions across a range of production rate categories using the same proportions as the 2009 well completion data.

We also made an effort to account for the number of storage vessels that would already be subject to and controlled under state environmental regulations. We analyzed the regulations in the 11 states that represented 95 percent of the total production of crude oil and condensate in the U.S. (according to production information published by the EIA). These states were Alaska, California, Colorado, Kansas, Louisiana, Montana, North Dakota, New Mexico, Oklahoma, Texas and Wyoming. These storage vessels were then subtracted from the overall count of storage vessels that would be subject to the final rule.

As a result, we estimated that there may be as many as 46,000 new condensate and crude oil storage vessels installed that would be subject to the NSPS from August 23, 2011 (the date upon which new, modified or reconstructed storage vessels become affected facilities under the NSPS), until October 15, 2015. This is an average of approximately 11,600 storage vessels per year, or about 970 per month. By the current compliance date of October 15, 2013, over 20,000 storage vessels will have come online since the original proposal date. These units will need to be controlled by October 15, 2013, under the current final NSPS.

Based on our reanalysis, we have reason to believe that there was already significant demand for storage vessel emissions control devices prior to the 2012 NSPS. For example, as discussed above, several states require operators to control VOC emissions from storage vessels. The EPA received information from the oil and natural gas industry indicating that 3,680 control devices could be manufactured per year as of 2012, or about 300 per month. We assumed that, since the NSPS requirements were not yet finalized when the agency received this information, most of this supply of equipment was being purchased by operators needing to meet state requirements. The 300 control devices per month discussed above will not be sufficient to satisfy NSPS requirements.

We further believe the supply of combustors will lag demand. Due to their uncertainty, manufacturers will delay scaling-up production until they are confident of the requirements of the manufacturer test protocol, for which we are proposing certain revisions and clarifications in this action and intend to finalize later this year. Manufacturers also need to make sure their models will pass the test and will undergo a favorable review by the EPA before investing in scale-up of operations. The manufacturer test protocol is discussed in section VI.C below.

The information available to the EPA leads us to conclude that, even with the uncertainty described above, the control device industry will be able to ramp up production each month by about 100 units over the previous month, beginning now, with our proposed revisions to the manufacturer test protocol, to a production capacity of about 1,400 per month, or about 17,000 per year, by April 15, 2014. With these projections in mind, it is clear that there will be an insufficient number of control devices on the market to meet the demand for control devices by the current compliance date of October 15, 2013, in addition to the ongoing demand for control devices from units that become affected after October 15, 2013. In fact, given these projections, it is unlikely that supply of control devices will meet existing and new demand until 2016.

We are concerned about delaying control of all storage vessels affected facilities until 2016. In order to move the compliance date to earlier than 2016, and in an attempt to match supply and demand in the most efficient and environmentally protective manner, we are considering that the BSER constitutes measures other than immediate control for those that have come online to date (i.e., Group 1). Specifically, we are proposing a two-part requirement: (1) These sources provide initial notification to the EPA by October 15, 2013; and (2) for any of these storage vessels that experiences an event on or after April 12, 2013, that potentially results in emissions increasing, the owner or operator would be subject to the same control requirements as those in Group 2.

The proposed approach not only would avoid delaying controlling all units until 2016, it would also help to some degree with proper allocation of the limited supplies of control devices in the near future and would ensure that those devices are used at the vessels expected to have the most significant emissions. As discussed in section VI.A.4 below, all oil and natural gas wells decline in production over time, with corresponding declines in reservoir pressure and liquids production. Often these declines are relatively rapid and can occur over a year or two. Accordingly, emissions from storage vessels in Group 1 may have declined significantly (potentially below the 6 tpy threshold for some) by the time controls are available to all affected sources. We recognize, however, that the emissions of these Group 1 affected facilities could increase again due to an event leading to higher emissions (e.g., if an additional well comes online feeding the vessel or a well feeding the storage vessel is later refractured or otherwise stimulated leading to an increase in production). We are therefore proposing that, if such an increase occurs, the Group 1 sources comply with control requirements that apply to Group 2.

Based upon the projected buildup of control device manufacturing capacity (i.e., an increase in production capacity of about 100 units per month, beginning now, to a production capacity of about 1,400 per month, or about 17,000 per year, by April 15, 2014) and, if control is not required initially for Group 1, the EPA expects that by April 15, 2014, there will be sufficient supply of equipment for Group 2. Accordingly, we are proposing that Group 2 implement the control requirements by April 15, 2014, or 60 days after startup, whichever is later. Additionally, the EPA believes manufacturers will be flexible in their ability to meet equipment demand increase in the future if crude oil and natural gas production increases. Because more controls will be applied to storage vessels as a result of this rule, the EPA believes that manufacturers will take advantage of scale economies and produce units at appropriate rates. We believe that the NSPS reconsideration, as proposed, will achieve environmental benefits while minimizing the risks of producers needing to slow activities to obtain appropriate equipment.

In summary, based on the discussion of control supply and demand presented above, we are proposing differing requirements for storage vessels in Group 1 and those in Group 2 in order to ensure that controls are available for new or modified storage vessel as soon as possible after they come online (i.e., when they have higher emissions). Specifically, for Group 2 (i.e., those that are constructed, modified or reconstructed on or after April 12, 2013), we propose to require reduction of emissions by 95 percent no later than 60 days after startup or April 15, 2014, whichever is later. For Group 1 (i.e., those that were constructed, modified or reconstructed after August 23, 2011, and before April 12, 2013, many of which may have experienced decline in emissions, we are proposing a two-part requirement as reflecting BSER: (1) These sources provide initial notification to the EPA by October 15, 2013; and (2) for any of these storage vessels that experience an event on or after April 12, 2013 that results in emissions increasing, the owner or operator would be subject to the same control requirements as those in Group 2 and would have to control emissions no later than 60 days after the event or April 15, 2014, whichever is later. Until any such emissions increase, there would be no further requirements for Group 1 storage vessels. We have included above in the preamble and in the proposed regulatory text some examples of events that would potentially lead to emission increase. We solicit comment on other examples or suggestions on how to define these events in the rule.

Further, we realize that the events discussed above that would likely lead to emissions increases are planned events. Operators of Group 1 storage vessels who plan for routing of additional wells to a storage vessel, fracturing or refracturing of a well feeding a storage vessel or other events are fully aware of such an event before it occurs. Therefore, we solicit comment on whether Group 1 storage vessels with increased emissions following such an event need the full 60 days provided for operators to apply controls.

We believe, based on our analysis of control supply and demand discussed above, that sufficient supply of controls will be available for Group 2 storage vessels by April 15, 2014. As a result, we propose that the BSER for these Group 2 storage vessels would require reduction of emissions by 95 percent no later than 60 days after date of construction, modification or reconstruction or April 15, 2014, whichever is later.

However, we are concerned with leaving affected sources with high emissions uncontrolled prior to April 15, 2014, and certain Group 1 units after that date. One option is to require control for those with emissions above a certain level based on the number of available control devices during this period. However, we have insufficient information regarding the number of high throughput (and likely to have higher VOC emissions) storage vessels. Therefore, we are unable to identify an appropriate threshold higher than 6 tpy that would allow us to require control of higher emission storage vessels earlier. We are also concerned that this may impact the ability of other affected sources to acquire control devices and comply by April 15, 2014. We solicit information on the number of storage vessels at different throughput levels (or VOC emission levels) to further inform our consideration of controlling higher emitting storage vessels earlier than April 15, 2014.

2. Definition of ''Storage Vessel''

In the final rule (77 FR 49490), the EPA defined ''storage vessel,'' in relevant part, as ''a unit that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provides structural support and is designed to contain an accumulation of liquids or other materials.'' Several petitioners took issue with this definition and expressed particular concern that the storage vessel definition in the final rule inadvertently included nearly every container in the oil and gas production, natural gas processing, and natural gas transmission and storage segments. For example, one petitioner stated that the definition as written could potentially encompass a drinking water bottle. The petitioner stated further that while the drinking water bottle would not exceed the 6 tpy VOC potential emissions threshold, which was provided elsewhere in the final rule, each site would have to maintain documentation on each and every container on-site to prove that the potential VOC emissions were less than 6 tpy.

We agree that the current definition is unclear and propose to amend the definition of ''storage vessel'' in § 60.5430 of the final rule to read, in relevant part, ''a tank or other vessel that is designed to contain 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.''

The proposed amended definition now specifically calls out the type of materials that must be stored in the vessel to meet the definition, thereby clarifying the scope of storage vessels the EPA intended to cover under the NSPS. The proposed definition reflects the EPA's intent, as discussed in the original rulemaking. For example, in the discussion of our storage tank analysis in the preamble to the proposed rule, we stated that ''[c]rude oil, condensate and produced water are typically stored in fixed-roof storage vessels.'' 76 FR 52763. Similarly, in the preamble discussion of the estimated impacts, we addressed only vessels storing these types of materials. Thus, we indicated at proposal that our intent was to regulate only certain storage vessels (i.e., those storage vessels that may likely emit VOC emissions), not every container.

We had previously believed that, by including a VOC emissions threshold in the storage vessel control requirements in § 60.5395 of the final rule, the rule effectively limited the applicability of the storage vessels emission standards to only storage vessels containing crude oil, condensate, intermediate hydrocarbon liquids, or produced water because, in all likelihood, only tanks storing these materials would have the potential to emit VOC at or above the threshold. However, as the petitioners pointed out, the definition in the final rule was stated in broad enough terms that a reasonable interpretation of the definition could lead to confusion as to which containers were considered to be storage vessels. If left unchanged, the storage vessel definition could result in a significant burden on the owner or operator because every container on-site may have to be identified and potential VOC emissions determined (and requisite records maintained). The proposed amendments to the storage vessel definition now limit the definition to vessels containing only those types of materials for which we originally intended the NSPS to apply. To provide further clarification, we are proposing to add definitions in § 60.5430 for condensate, hydrocarbon liquid and produced water. We are proposing to adopt the definitions of these terms in 40 CFR part 63, subpart HH, which similarly requires 95-percent emission reduction from storage vessels that are major sources of hazardous air pollutants.

3. Storage Vessel Affected Facility Definition at § 60.5365(e)

In § 60.5365(e) of the final rule (77 FR 49490), we described the affected facility as ''[e]ach storage vessel affected facility, which is a single storage vessel located in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment.'' In § 60.5395 of the final rule, we require affected facilities emitting more than 6 tpy VOC to reduce VOC emissions by 95.0 percent.

Several petitioners stated that by not including the VOC emissions threshold in the affected facility definition, the EPA significantly increased the population of storage vessels potentially affected by the rule. The petitioners asserted that this very broad description of affected facility would result in unnecessary notification, recordkeeping and reporting burden, even if the storage vessels had no VOC emissions or are not subject to the control requirement.

We had not intended to subject storage vessels emitting below the 6 tpy VOC to the NSPS. Although the final rule is clear that storage vessels that have always had a PTE below the 6 tpy threshold are not subject to the control requirement, the rule inadvertently requires them to comply with the recordkeeping and reporting requirements in the final rule, which are largely associated with demonstrating and assuring compliance with the control requirement. Further, having these storage vessels be subject to the NSPS could trigger state permitting requirements. We believe these associated burdens are not necessary for storage vessels with VOC emissions below 6 tpy, which are not subject to the control requirement. On the contrary, we believe it is important to limit the scope of the NSPS only to those storage vessels the EPA intended to control, thereby avoiding unnecessary unintended consequences. For the reason stated above, we agree with petitioners' suggestion and are proposing to include the 6 tpy PTE threshold in the ''storage vessel affected facility'' definition in 60.5395(e).

Petitioners asserted that a storage vessel's emissions for purposes of applying the emissions threshold should consider any legal and practically enforceable emissions limit below 6 tpy. We are proposing to clarify at § 60.5365(e) that a source can take into account any legal and practically enforceable emissions limit under federal, state, local or tribal authority when determining the VOC emission rate for purposes of this threshold (i.e., they would not be subject to the storage vessel provisions of the NSPS if their potential to emit VOC was required to be less than 6 tpy under such limitation and they in fact were below that limit).

In addition, petitioners had suggested that sources with a legal and practically enforceable requirement for at least 95 percent control should not be affected facilities under the NSPS. The petitioners' proposal seems to suggest that as long as an emission limitation equivalent to the NSPS emission standards can be enforced by state or another federal requirement, compliance with the NSPS is not necessary. The EPA is concerned regarding the absence of EPA oversight, which CAA section 111 contemplates. We are also concerned that such a broad proposition, if adopted, would not be limited to just this NSPS but may inadvertently impact other future EPA regulations as well. Although we are not proposing to add such a provision in this action, we solicit comment on the petitioners' suggested approach, in particular on how the EPA may implement oversight of the enforcement of this NSPS and on distinguishing characteristics between this NSPS and other EPA regulations to warrant this approach here without inadvertently extending its use in other rulemakings. We also solicit comment if such an approach is permissible under CAA section 111.

The final rule allows 30 days to determine emissions, followed by another 30 days to install controls, only for storage vessels located at well sites with no existing well in production. For storage vessels located at well sites with one or more wells in production, the NSPS allowed no time for determining emissions but required control on startup. This provision was based on the assumption that, for storage vessels at ongoing production sites, the owner or operator would be able to anticipate the rate and characteristics of the liquids entering the vessel, which would obviate the need for time for emissions determination and would allow the appropriate controls to be applied on startup if needed. Petitioners raised this provision as problematic and stated that the NSPS should provide time for emissions determination and control device installation for all storage vessels, not just ones at locations with no existing well in production. According to the petitioners, in many cases at well sites and at other locations, emissions cannot be estimated until the storage vessel is in operation, given the uncertainties in flowrate and other characteristics of the liquid flowing to the vessel. When a new well comes online, even at a location where wells are already in production, liquids from the new well can have significantly different characteristics than liquids from the existing wells. Further, petitioners noted that the language in the final rule could be incorrectly interpreted that only storage vessels located at well sites were potentially subject to the NSPS. In light of the new information, we propose that all new, modified or reconstructed Group 2 storage vessels have up to 30 days after startup to determine the emissions rate and, if emissions are estimated to be 6 tpy or more, controls must be in operation no later than 60 days from startup or by April 15, 2014, (our proposed new date for implementing control), whichever is later. It is our intent that the NSPS address VOC emissions from storage vessels located not only at wells but at any location from the well to the point of custody transfer to an oil pipeline or to the point of custody transfer from the natural gas transmission and storage segment to the local distribution company.

Petitioners also asserted that 60 days was not a sufficient period to determine emissions and install controls if required, although they did not provide details supporting this assertion. We believe that 60 days is sufficient and propose to retain this period. We believe, since modeling is generally the method by which emissions are estimated, based on several parameters of the material entering the storage vessel, that 30 days is sufficient for determining whether emissions reach the threshold. Further, we believe that an additional 30 days is sufficient to install the combustor and the relatively simple associated closed vent system.

We are also proposing to add a provision to clarify that a storage vessel affected facility whose VOC emissions decrease to less than the threshold of 6 tpy, even for an extended time, will remain an affected facility. We believe this additional clarification is necessary, especially in light of our proposed alternative emission limit of less than 4 tpy uncontrolled VOC emissions, to address the situation where emissions from a storage vessel affected facility declines and later increases. We believe it is important to clarify for both the regulated community and regulatory agencies that such a storage vessel remains an affected facility and would be required to meet the emission standards of either the 95 percent VOC reduction requirement or the proposed alternative emission limit of less than 4 tpy VOC. This issue is related to the discussion below in section VI.A.4 pertaining to continued control device use after extended periods of low emissions.

One petitioner asserted that the final rule creates uncertainty because sources subject to the NSPS may trigger state minor or major source permitting requirements. Subsequently, the petitioner clarified that much of the uncertainty focuses on treatment of replacement storage vessels that are installed in cases of failure of existing storage vessels due to leakage or other issues. The petitioner was concerned that some state permitting programs require construction permits for sources that are affected facilities under any NSPS. Under subpart OOOO, a replacement storage vessel would be considered a new source and an affected facility if it has a PTE of 6 tpy or more and is put into service after August 23, 2011.

Although we understand that operators needing to install replacement tanks may potentially have difficulty meeting state permitting requirements, it is unclear how the NSPS could be revised to help address this issue. Accordingly, we solicit comment on how the NSPS could address the issue the petitioner raised.

4. Alternative Mass-Based Standard for Storage Vessel Affected Facilities

The petitioners pointed out that Wyoming [1] allows for control devices to be removed after sustained periods of uncontrolled emissions below the applicability threshold. The petitioners also contended that allowing control devices to be removed from lower emitting storage vessels would increase the number of control devices available to install on new storage vessels, which they assert would help alleviate the shortage of control devices discussed above in section VI.A.1.

Although this proposed rule includes an amendment to assure adequate supply of control devices, the number of future storage vessel affected facilities that would require control is uncertain and may exceed our estimated 970 per month (which we relied on in our proposed amendment to address this issue). We believe that petitioners' suggestion is a reasonable approach to help alleviate any potential control device shortage issue for the following reason. Storage vessels at oil and natural gas production sites are unlike many other sources in that emissions can reasonably be expected to decrease over time and, potentially, increase again under certain circumstances. After production declines, associated emissions would also decline. Petitioners' suggestion would help build a buffer against supply shortage by allowing control devices on these low emitting storage vessels to be relocated to control emissions from storage vessels that have just come online and emitting above 6 tpy. For the reason stated above, we are proposing that affected sources meet either the 95 percent VOC reduction standard or an alternative, mass-based numeric limit on uncontrolled emissions.

Petitioners suggested that 6 tpy, the applicability threshold for storage vessel affected facilities under the NSPS, also be used as the threshold for uncontrolled emissions for allowing removal of storage devices. We disagree that 6 tpy is the appropriate alternative limit. In the final NSPS rule, we did not establish 6 tpy as an emission limit. Rather, 6 tpy is an applicability threshold, at which level we have determined that it is cost effective to require installation and operation of a control device to achieve 95 percent VOC reduction. At 6 tpy uncontrolled emissions, 95 percent control would result in an emission rate of 0.3 tpy.

We think the appropriate limit would likely be something less than 4 tpy; we believe controlling storage vessels above that level could still achieve meaningful VOC reduction. We are therefore proposing to amend § 60.5395(a) to include both the existing VOC emissions reduction component and an alternative mass-based limit of less than 4 tpy for uncontrolled emissions. The proposed uncontrolled emission limit would be available to those who can demonstrate, based on records for the 12 months immediately preceding the demonstration and while the control is on, that the uncontrolled emissions during that 12 months period would have been below 4 tpy. This uncontrolled emission rate can be calculated using information available to the facility operator, including such parameters as separator pressure, liquid throughput and API gravity. We believe this alternate standard reflects the decline in production that all wells experience over time and allows control devices to be reused at other locations

[1] Oil and Gas Production Facilities, Chapter 6, Section 2 Permitting Guidance. March 2010.

which would help alleviate control device supply shortages. If, however, uncontrolled emissions increase to 4 tpy or above, the sources would need to once again comply with the 95 percent control requirement.

As mentioned above, we are proposing to amend § 60.5395(a) to require sources to achieve either: (1) 95-percent VOC reduction; or (2) uncontrolled VOC emissions of less than 4 tpy. We are proposing that operators electing the alternative emission limit would be required to determine and keep records of the storage vessel's emission rate at least monthly while operating under the alternative emissions limit. Similar to provisions in the final rule for determining annual emissions from storage vessels for applicability purposes, we propose that operators may use generally accepted models to estimate uncontrolled emissions.

We solicit comment on our proposal to establish an alternative, mass-based numeric limit on uncontrolled emissions. We also solicit comment on whether a limit of less than 4 tpy is appropriate and, if not, what an appropriate limit would be, including any supporting data and rationale. In addition, we solicit comment on whether frequencies other than monthly would be appropriate for the emissions determinations while operating under the alternative emissions limit, whether the frequency of such determinations should decrease after some number of periodic estimates below 4 tpy, and whether the emissions determination should be required only after some event that would likely increase emissions.

Under the final NSPS rule, owners and operators at well sites with no wells already in production have 30 days after determining emissions to procure and install control. As discussed elsewhere in this notice, we are proposing to provide such 30 days to owners and operators at all wells sites. We are similarly proposing here that, if a monthly emissions determination indicates VOC emissions of 4 tpy or greater, the owner or operator would need to comply with the 95 percent control standard by no later than 30 days after the determination indicated 4 tpy or greater VOC emissions. Under our proposed compliance demonstration requirement, the alternative emission limit would again be available for that storage vessel only after another 12 months of uncontrolled VOC emissions less than 4 tpy while operating under the 95 percent VOC reduction requirement.

While we think that owners and operators may need time to reinstall control, we are concerned with leaving the emissions unaddressed during that period. We therefore solicit comment on whether a 30 day period is needed for owners and operators to reinstall control and what appropriate measures should be taken during the period to control emissions.

B. Periodic Monitoring and Testing of Closed-Vent Systems and Control Devices

The final NSPS (77 FR 49490) requires that VOC emissions be reduced by 95 percent for storage vessel affected facilities with VOC emissions of 6 tpy or more. We had anticipated that most owners and operators will use a combustion control device to achieve the required level of emission reduction. The final NSPS requires an initial performance test, installation and operation of CPMS and calculation of daily averages of the continuously monitored parameters, among other requirements. As discussed above in section VI.A.1, we have revised our estimate of the number of storage vessels affected by the final rule from about 300 to approximately 11,600 per year.

Several of the petitioners assert that the compliance monitoring requirements are overly complex and stringent given the large number affected storage vessels each year and the remoteness of the well sites at which they are installed. The petitioners argue that the well sites are unmanned for periods of time up to a month. According to the petitioners, proper operation of the CPMS and performance of other monitoring requirements would require specialized personnel to be on-site far more frequently. The petitioners also point out that most well sites do not have the communications and power infrastructure in place to operate the CPMS.

The petitioners also argue that insufficient resources are available to perform the required Method 21 testing of the closed-vent systems and that lengthy (the NSPS requires a 2 hour observation) Method 22 testing of combustion control devices is unnecessary and overly burdensome.

Based on our revised estimate of the number of storage vessel affected facilities, combined with our knowledge of the remoteness of these locations, we believe that petitioners have raised legitimate issues regarding the monitoring and testing requirements relative to control devices for storage vessels in the final NSPS rule and that these issues warrant our reconsideration of these requirements. The EPA also recognizes that delaying implementation of the storage vessel NSPS pending this reconsideration would further delay the important environmental benefits that will result from the NSPS. We are working with stakeholders to fully evaluate these issues and intend to complete our reconsideration of these monitoring and testing requirements by the end of 2014.

The additional information discussed above has raised significant concerns that the compliance monitoring provisions and field testing provisions of the final rule may not be appropriate for this large number of affected storage vessels, which is much greater than we had expected and with many in remote locations. Therefore, we are proposing certain streamlined monitoring and continuous compliance demonstration requirements to provide assurance during the EPA's reconsideration process, that closed-vent systems and control devices are designed and operated properly and that the control devices, when in use, are achieving the required 95 percent control.

We believe the proposed requirements do not pose the concerns raised by the petitioners regarding burden imposed by the final rule due to the vast number of facilities and remote locations involved. The requirements we are proposing are intended to be carried out by personnel routinely at the well sites without the need for specialized training or instrumentation.

Meanwhile, we will continue to fully evaluate the compliance demonstration and monitoring issues raised by the petitioners. We intend to complete our reconsideration of these requirements, along with other issues for which we intend to grant reconsideration, at a later date.

As mentioned above, we are proposing a suite of streamlined compliance and monitoring requirements that would apply instead of the requirements in the final rule during the EPA's reconsideration of associated issues. First, under § 60.5416, instead of the detailed Method 21 monitoring requirements, the proposed requirements would include inspection requirements for covers and closed-vent systems. The proposed inspection requirements include monthly sensory (i.e., OVA) inspections of: (1) Closed-vent system joints, seams and other sealed connections (e.g., welded joints); (2) other closed-vent system components such as peak pressure and vacuum valves; and (3) the physical integrity of tank thief hatches, covers, seals and pressure relief valves.

Second, under § 60.5417, instead of the CPMS requirements, the proposed requirements would include the following inspection requirements: (1) Monthly observation for visible smoke emissions employing section 11 of EPA Method 22 for a 15 minute period; (2) monthly visual inspection of the physical integrity of the control device; and (3) monthly check of the pilot flame and signs of improper operations. If the pilot flame is absent or if smoking is observed more than 1 minute during a 15-minute period, then the operator must take further action to ascertain the cause of the malfunction, including checking the combustor air vent for obstructions and checking for liquid from the knockout drum reaching the combustor (i.e., the knockout drum is not draining properly). The owner or operator would be required to take corrective action as soon as practicable and as safely as possible after visible smoke emissions or other problems are observed. Each inspection of the storage vessel and associated control device and closed-vent system would be required to be documented in a logbook required to be kept securely on-site. Many storage vessels already have weatherproof containers mounted nearby where other records are kept.

Third, we are proposing requirements that would apply instead of the field performance testing requirements in § 60.5413. We are proposing to require that, where controls are used to reduce emissions, sources use control devices that by design can achieve 95 percent or more emission reduction and operate such devices according to the manufacturer's instructions, procedures and maintenance schedule, including appropriate sizing of the combustor for the application. Documentation that a combustor is designed for at least 95 percent control could include such items as manufacturer technical literature showing combustor performance, manufacturer's guarantee of control efficiency, relevant test reports, etc. We are retaining and strongly encourage use of the option for operators to employ combustor models that pass manufacturer-conducted performance tests according to the EPA combustor test protocol. We believe that operators have an incentive to use manufacturer-tested combustors, since those combustors are not subject to subsequent performance tests. However, we seek comment on other potential approaches to provide incentive for operators to employ manufacturer-tested combustor models.

We solicit input from the public and from states with relevant experience on the effectiveness of these types of streamlined monitoring techniques in assuring compliance with the emission reduction measures of the NSPS. Further, we encourage operators to document their experiences with these streamlined measures to better inform the EPA in its future evaluation of these measures.

C. Test Protocol for Combustion Control Devices

The proposed oil and natural gas sector NESHAP (76 FR 52738) included an option for manufacturers' performance testing of certain combustion control devices as an alternative to on-site testing by the owner or operator. We explained the need for this alternative in the preamble to the proposed rule (see 76 FR 52785). The proposed NSPS also included this option. In order to promote consistency between the oil and natural gas sector NSPS and NESHAP, the proposed NSPS rule language referenced the relevant sections in the NESHAP (40 CFR 63, subpart HH) for the manufacturers' test protocol.

We received comments to the proposed rule indicating that the cross-referencing to the NESHAP was burdensome and posed other problems. In response, we eliminated the cross-referencing by incorporating the manufacturers' performance test protocol from the NESHAP into the final NSPS.

After publication of the final rule, some of the petitioners pointed out that the language we used in the final NSPS appeared to indicate that manufacturers' performance testing is mandatory for all combustion control devices. The petitioners also noted inconsistencies between the regulatory language in the NSPS and NESHAP for the manufacturers' performance test protocol.

In response to the petitioners' comments, we reviewed the manufacturers' performance test protocol in the NSPS. We found that not all of the revisions made to the NESHAP protocol after proposal were carried over to the NSPS. These revisions involved modifications to the test procedures and reporting requirements. This inadvertent error led to most of the issues raised by the petitioners. It was the EPA's intent to have essentially the same manufacturers' performance test protocol and reporting requirements in both the NSPS and the NESHAP.

In response, we are proposing to amend § 60.5413(d) to be consistent with the current requirements of 40 CFR 63.772(h) to ensure consistency between the rules. This effort will also streamline testing, because enclosed combustor models that pass the test protocol will meet both the NSPS and NESHAP requirements, eliminating the need to test each model for NSPS and NESHAP compliance separately.

Additionally, we are proposing to modify the reporting requirements for owners and operators using a manufacturer tested control device in the NSPS to match the same requirements in the NESHAP. We are proposing to revise § 60.5412(a)(i) to clarify that the manufacturers' performance testing applies to the model of the combustion control device, not each individual control device. Finally, we are proposing to clarify that manufacturers' performance testing is optional by revising § 60.5415(e)(2)(vii).

As discussed in the 2011 proposed rule preamble (76 FR 52785), performance testing of control devices that are not configured with a distinct combustion chamber presents several technical issues that are more optimally addressed through manufacturer testing, and once these units are installed at a facility, through periodic inspection and maintenance in accordance with manufacturers' recommendations.

In the final rule (77 FR 49490), the EPA provided a path for compliance that involved operators purchasing certified combustors combined with annual compliance demonstrations. We would like to explore whether the compliance certification process could be made sufficiently robust to reduce or minimize future compliance demonstration obligations. We solicit comment on the desirability of such an approach and suggestions on how to design a sufficiently rigorous certification process to assure compliance while minimizing burden on both operators and implementing agencies.

We are also soliciting comment on one potential framework for implementing the certification process for enclosed combustors used to meet the emissions standards under NSPS subpart OOOO and NESHAP subpart HH. The EPA notes that the following concept is one possible compliance tool, and welcomes comment on this or any other compliance tool incorporating an enclosed combustor certification program. We plan to continue to work with all stakeholders as we further develop this concept with the goal of ultimately designing a pathway that assures compliance without slowing responsible production of oil and natural gas.

One possible compliance tool includes a requirement for owners or operators to use enclosed combustors that have been certified by the EPA. The manufacturer's role would be to submit a performance test for each unique model manufactured. The manufacturer could submit the performance test to the EPA where it would be evaluated for completeness and compliance with the emissions standard required by the rule. In order to ease compliance, the EPA could require that the manufacturer's control device be sold as ''compliance ready''; i.e. equipped with a thermocouple (or equivalent device) and data recorder. Initial discussions with control device manufacturers indicate that this may already be common practice. The EPA requests comment as to whether enclosed combustors could be sold as ''compliance ready,'' and whether such an approach would ease compliance.

An owner or operator that purchases a certified control device could demonstrate initial compliance by providing proof of purchase of the EPA-certified device, in the form of a purchase order or receipt. The EPA could supplement such a requirement with a manufacturer reporting requirement providing the names of entities that had purchased certified control devices. Such a model of reporting may ensure that the purchase and installation of certified devices has occurred, and could also ensure compliance with the rule.

The owner or operator could demonstrate ongoing compliance, in part, through monitoring of the presence of the continuous pilot flame. As discussed previously, a certified control device could be sold as ''compliance ready''; i.e., it would be equipped with a thermocouple (or equivalent device) and data recorder thereby simplifying the continuous compliance demonstration for the owner or operator.

We welcome comment on this potential compliance option or on other compliance options.

D. Annual Report and Compliance Certification

Petitioners also asserted that the 30–day period to submit the annual report in § 60.5420(b) is too short because of the large number of affected facilities to be included in the annual reports of many companies and the requirement to have the reports signed by a responsible official. We agree that the 30-day period may be too short to compile all of the required information and properly inform a responsible official such that the official may certify the truth, accuracy and completeness of the annual report. Therefore, we are proposing to amend § 60.5420(b) to allow 90 days from the end of the compliance period for submittal of the annual report and compliance certification. This is consistent with Title V reporting and certification requirements.

One petitioner pointed out that the public was not provided an opportunity to comment on the requirement in the final rule for certification by a responsible official and that such certification, modeled on Title V requirements, is not appropriate for the oil and natural gas sector due to the number of sources involved and other factors. We have reconsidered the certification requirement and, for the same reasons provided in the final rule preamble (77 FR 49527), we are proposing to retain this requirement. Specifically, we believe that self-certification is an important mechanism for assuring the public that the information submitted by each facility is accurate. In addition, the Title V program has successfully employed self-certification since its inception and we believe it is a good model for the certification provisions in the final rule. For these reasons, we are proposing to retain the certification provision in the final rule.

We believe that the petitioner's main concern may have been the 30-day period allowed for submittal of the certification, which the petitioner claimed insufficient in light of the number of affected sources. As discussed above, we are proposing to allow 90 days for submitting the compliance certification.

E. Properly Designed Storage Vessels, Closed-Vent Systems and Control Devices

It is the EPA's experience that proper design and sizing of storage vessels and their associated closed-vent systems and control devices are important considerations in effective control of VOC emissions from storage vessels. For example, such factors as type of gasket material, weighting of thief hatch covers, release point of pressure relief valves, sizing of the storage vessel itself, diameter of lines conveying vapor to the control device, sizing of the control device and other factors can greatly affect the ability of the system to achieve the control efficiency required by the NSPS. Improper design or operation of the storage vessel and its control system can result in occurrences where peak flow overwhelms the storage vessel and its capture systems, resulting in emissions that do not reach the control device, effectively reducing the control efficiency. We believe that it is essential that operators employ properly designed, sized and operated storage vessels to achieve effective emissions control. We believe that such efforts on the part of owners and operators can result in more effective control of VOC emissions from storage vessels subject to the NSPS. Although we are not proposing today to add requirements for proper design of storage vessels and associated closed-vent systems and control devices, we solicit comment on whether such provisions should be included in the final rule.

VII. Technical Corrections and Clarifications

Following publication of the final NSPS, we subsequently determined, following review of the petitions and discussions with affected parties, that the final rule warrants correction clarification in certain areas. The EPA is proposing corrections to applicability dates and monitoring, recordkeeping and reporting requirements for all affected facilities. In addition, we are proposing corrections that are editorial in nature including typographical and grammatical errors, as well as incorrect cross-references. Details of the specific changes we are proposing to the regulatory text may be found in the docket for this action.[2]

VIII. Impacts of This Proposed Rule

Our analysis shows that owners and operators of storage vessel affected facilities would choose to install and operate the same or similar air pollution control technologies under the proposed standards as would have been necessary to meet the previously finalized standards. We project that this rule will result in no significant change in costs, emission reductions or benefits. Even if there were changes in costs for these units, such changes would likely be small relative to both the overall costs of the individual projects and the overall costs and benefits of the final rule. Since we believe that owners and operators would put on the same controls for this proposed rule that they would have for the original final rule, there should not be any incremental costs related to this proposed revision.

A. What are the air impacts?

We believe that owners and operators of storage vessel affected facilities will install the same or similar control technologies to comply with the revised standards proposed in this action as they would have installed to comply

[2] Memorandum from Moore, Bruce, U.S. EPA, to Docket No. EPA–HQ–OAR–2010–0505, ''Technical Corrections to the Final Oil and Natural Gas Sector New Source Performance Standards.'' January 7, 2013.

with the previously finalized standards. Accordingly, we believe that this proposed rule will not result in significant changes in emissions of any of the regulated pollutants.

B. What are the energy impacts?

This proposed rule is not anticipated to have an effect on the supply, distribution or use of energy. As previously stated, we believe that owners and operators of storage vessel affected facilities would install the same or similar control technologies as they would have installed to comply with the previously finalized standards.

C. What are the compliance costs?

We believe there will be no significant change in compliance costs as a result of this proposed rule because owners and operators of storage vessel affected facilities would install the same or similar control technologies as they would have installed to comply with the previously finalized standards.

D. What are the economic and employment impacts?

Because we expect that owners and operators of storage vessel affected facilities would install the same or similar control technologies to meet the standards proposed in this action as they would have chosen to comply with the previously finalized standards, we do not anticipate that this proposed rule will result in significant changes in emissions, energy impacts, costs, benefits or economic impacts. Likewise, we believe this rule will not have any impacts on the price of electricity, employment or labor markets or the U.S. economy.

E. What are the benefits of the proposed standards?

As previously stated, the EPA anticipates the oil and natural gas sector will not incur significant compliance costs or savings as a result of this proposal and we do not anticipate any significant emission changes resulting from this rule. Therefore, there are no direct monetized benefits or disbenefits associated with this proposed rule.

IX. Statutory and Executive Order Reviews

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

This action is not a ''significant regulatory action'' under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011).

A RIA was prepared for the April 2012 final rule and can be found at: *http://www.epa.gov/ttn/ecas/regdata/RIAs/oil_natural_gas_final_neshap_nsps_ria.pdf.* Because this action does not impose new compliance costs on affected sources, we project that this rule will result in no significant change in costs, emission reductions or benefits in 2015, the year of full implementation of the NSPS.

B. Paperwork Reduction Act

This action does not impose any new information collection burden. Today's notice of reconsideration does not change the information collection requirements previously finalized and, as a result, does not impose any additional burden on industry. However, OMB has previously approved the information collection requirements contained in the existing regulations (see 77 FR 49490) under the provisions of the PRA, 44 U.S.C. 3501, et seq., and has assigned OMB control number 2060–0673). The OMB control numbers for the EPA's regulations are listed in 40 CFR part 9 and 48 CFR chapter 15.

C. Regulatory Flexibility Act

The RFA generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this rule on small entities, a small entity is defined as: (1) A small business in the oil or natural gas industry whose parent company has no more than 500 employees (or revenues of less than $7 million for firms that transport natural gas via pipeline); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this proposed rule on small entities, I certify that this action will not have a SISNOSE. In determining whether a rule has a SISNOSE, the impact of concern is any significant *adverse* economic impact on small entities, since the primary purpose of the regulatory flexibility analyses is to identify and address regulatory alternatives ''which minimize any significant economic impact of the rule on small entities.'' 5 U.S.C. 603 and 604. Thus, an agency may certify that a rule will not have a SISNOSE if the rule relieves regulatory burden, or otherwise has a positive economic effect on all of the small entities subject to the rule.

The EPA has determined that none of the small entities will experience a significant impact because the notice of reconsideration imposes no additional compliance costs on owners or operators of affected sources. We have therefore concluded that today's notice of reconsideration will not result in a SISNOSE. We continue to be interested in the potential impacts of the proposed rule on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act of 1995

This action contains no federal mandates under the provisions of Title II of the UMRA of 1995, 2 U.S.C. 1531–1538 for state, local or tribal governments or the private sector. The action imposes no enforceable duty on any state, local or tribal governments or the private sector. Therefore, this action is not subject to the requirements of sections 202 or 205 of the UMRA.

This rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. This action contains no requirements that apply to such governments nor does it impose obligations upon them.

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, as specified in Executive Order 13132. This proposal is a reconsideration of an existing rule and imposes no new impacts or costs. Thus, Executive Order 13132 does not apply to this action.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between the EPA and state and local governments, the EPA specifically solicits comment on this proposed action from state and local officials.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It will not have substantial direct effect on tribal governments, on the relationship between the federal government and Indian tribes or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

The EPA specifically solicits additional comment on this proposed action from tribal officials.

G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

This action is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it is not economically significant as defined in Executive Order 12866, and because the agency does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. This action has no impacts thus health and risk assessments were not conducted.

The public is invited to submit comments or identify peer-reviewed studies and data that assess effects of early life exposure to HAP from oil and natural gas sector activities.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12(d) of the NTTAA, Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs the EPA to use VCS in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures and business practices) that are developed or adopted by VCS bodies. The NTTAA directs the EPA to provide Congress, through OMB, explanations when the agency decides not to use available and applicable VCS.

This proposed rulemaking does not involve technical standards. Therefore, the EPA is not considering the use of any VCS.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies and activities on minority populations and low-income populations in the United States.

The EPA has determined that this proposed rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. This proposal is a reconsideration of an existing rule and imposes no new impacts or costs.

List of Subjects in 40 CFR Part 60

Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping.

Dated: March 28, 2013.

Bob Perciasepe,

Acting Administrator.

For the reasons set out in the preamble, Title 40, chapter I of the Code of Federal Regulations is proposed to be 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. 7401, *et seq.*

Subpart OOOO—[Amended]

■ 2. Section 60.5365 is amended by revising paragraph (e) to read as follows:

§ 60.5365 Am I subject to this subpart?

* * * * *

(e) Each storage vessel affected facility, which is a single storage vessel located in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment and has the potential for VOC emissions equal to or greater than 6 tpy taking into account requirements under a legally and practically enforceable limit in an operating permit or by other mechanism. 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. A storage vessel that has been determined in accordance with § 60.5395(c) to have a potential to emit of less than 6 tpy is not a storage vessel affected facility, provided that the owner or operator has maintained record of such determination.

* * * * *

■ 3. Section 60.5380 is amended by:

■ a. Revising paragraph (a)(2); and

■ b. Revising paragraphs (b) and (c).

The revisions read as follows:

§ 60.5380 What standards apply to centrifugal compressor affected facilities?

* * * * *

(a) * * *

(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 § 60.5411(b), that is connected through a closed vent system that meets the requirements of § 60.5411(a) and routed to a control device that meets the conditions specified in § 60.5412(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 flow line, as defined in § 60.5430.

(b) You must demonstrate initial compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5410(b).

(c) You must demonstrate continuous compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5415(b).

* * * * *

■ 4. Section 60.5390 is amended by:

■ a. Revising the introductory text;

■ b. Revising paragraph (a); and

■ c. Revising paragraphs (c)(1) and (2).

The revisions read as follows:

§ 60.5390 What standards apply to pneumatic controller affected facilities?

For each pneumatic controller affected facility you must comply with the VOC standards, based on natural gas as a surrogate for 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. However, you must comply with the requirements in either paragraph (b)(2) or (c)(2), as applicable.

(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.

* * * * *

(c)(1) Each pneumatic controller affected facility constructed, modified or reconstructed on or after October 15, 2013, at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller affected facility at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline 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 § 60.5420(c)(4)(iii).

* * * * *

■ 5. Section 60.5395 is revised to read as follows:

§ 60.5395 What standards apply to storage vessel affected facilities?

Except as provided in paragraph (h) of this section, you must comply with the standards in this section for each storage vessel affected facility.

(a)(1) If you are the owner or operator of a Group 1 storage vessel affected facility as defined in this subpart, you must comply with paragraph (b) of this section.

(2) If you are the owner or operator of a Group 2 storage vessel affected facility as defined in this subpart, you must comply with paragraphs (c) through (g) of this section.

(b) *Requirements for Group 1 storage vessel affected facilities.* (1) You must submit a notification identifying each Group 1 storage vessel, including its location, by October 15, 2013.

(2) On or after April 12, 2013, if you have an event that could reasonably be expected to increase VOC emissions from your Group 1 storage vessel, you must comply with paragraphs (d) through (g) of this section. For the purposes of this section, an event includes, but is not limited to, the examples specified in paragraphs (b)(2)(i) through (iv) of this section.

(i) Routing a well to the storage vessel that was not previously routed to the storage vessel.

(ii) Conducting hydraulic fracturing on a well routed to the storage vessel.

(iii) Conducting hydraulic refracturing on a well routed to the storage vessel.

(iv) Any other event that could increase the VOC emissions from the storage vessel affected facility.

(c) *Emissions determination.* You must comply with paragraphs (c)(1) or (2) of this section.

(1) For Group 2 storage vessels constructed, modified or reconstructed before April 15, 2014, you must determine the VOC emission rate no later than April 15, 2014, or 30 days after startup, whichever is later. To make this determination, you must use any generally accepted model or calculation methodology. If the VOC emission rate is determined to be equal to 6 tpy or greater, you must comply with paragraphs (d) through (g) of this section.

(2) For Group 2 storage vessels constructed on or after April 15, 2014, you must determine the VOC emission rate using any generally accepted model or calculation methodology within 30 days after startup and minimize emissions to the extent practicable during the 30-day period using good engineering practices through the period prior to installation of control. If the VOC emission rate is determined to be equal to 6 tpy or greater, you must comply with paragraphs (d) through (g) of this section.

(d) You must comply with the requirements of paragraph (d)(1) or (2) of this section.

(1) Reduce VOC emissions by 95.0 percent or greater by April 15, 2014 or within 60 days after startup, whichever is later.

(2) Maintain the VOC emissions from the storage vessel affected facility at less than 4 tpy without considering control, provided that you have been using a control device and have demonstrated that the VOC emissions have been below 4 tpy without considering control for at least the 12 consecutive months immediately preceding the demonstration. You must determine the VOC emission rate each month using any generally accepted model or calculation methodology and minimize emissions to the extent practicable during this period using good engineering practice. Monthly calculations must be separated by at least 14 days.

(e) Control requirements. (1) Except as required in paragraph (e)(2) of this section, if you use a control device (such as an enclosed combustion device or vapor recovery device) to reduce emissions from your storage vessel affected facility, you must equip the storage vessel with a cover that meets the requirements of § 60.5411(b) and is connected through a closed vent system that meets the requirements of § 60.5411(c), and you must route emissions to a control device that meets the conditions specified in § 60.5412(c) and (d). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a flow line, as defined in § 60.5430. If you route emissions to a flow line, you must equip the storage vessel with a cover that meets the requirements of § 60.5411(b) and is connected through a closed vent system that meets the requirements of § 60.5411(c).

(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.

(f) *Reserved.*

(g) *Compliance, notification, recordkeeping, and reporting.* If you use a control device to reduce emissions or if you route your emissions to a flow line, you must comply with paragraphs (g)(1) and (2) of this section.

(1) You must demonstrate initial compliance with standards as required by § 60.5410(h).

(2) You must demonstrate continuous compliance with standards as required by § 60.5415(e)(3).

(3) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420.

(h) *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, 40 CFR part 63, subparts G, CC, HH, or WW.

■ 6. Section 60.5410 is amended by:
■ a. Revising the introductory text;
■ b. Revising paragraphs (a)(3) and (4);
■ c. Revising paragraphs (b)(2) through (5);
■ d. Revising paragraphs (b)(7) and (8);
■ e. Revising paragraph (d) introductory text;
■ f. Revising paragraphs (d)(1) and (2);
■ g. Revising paragraph (d)(4);
■ h. Removing and reserving paragraph (e); and
■ i. Adding paragraphs (h) and (i).

The revisions and addition read as follows:

§ 60.5410 How do I demonstrate initial compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my 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 (i) of this section. The initial compliance period begins on October 15, 2012, or upon initial startup, whichever is later, and ends no later than one year after the initial startup date for your affected facility or no later than one year after October 15, 2012. The initial compliance period may be less than one full year.

(a) * * *

(3) You must maintain a log of records as specified in § 60.5420(c)(1)(i) through (iv) for each well completion operation conducted during the initial compliance period.

(4) For each gas well affected facility subject to both § 60.5375(a)(1) and (3), as an alternative to retaining the records specified in § 60.5420(c)(1)(i) through (iv), you may maintain records 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 gas 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 GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

(b) * * *

(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 § 60.5411(b) that is connected through a closed vent system that meets the requirements of § 60.5411(a) and is routed to a control device that meets the conditions specified in § 60.5412(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 flow line, as defined in § 60.5430.

(3) You must conduct an initial performance test as required in § 60.5413 within 180 days after initial startup or by October 15, 2012, whichever is later, and you must comply with the continuous compliance requirements in § 60.5415(b)(1) through (3).

(4) You must conduct the initial inspections required in § 60.5416(a) and (b).

(5) You must install and operate the continuous parameter monitoring systems in accordance with § 60.5417(a) through (g), as applicable.

* * * * *

(7) You must submit the initial annual report for your centrifugal compressor affected facility as required in § 60.5420(b)(3) for each centrifugal compressor affected facility.

(8) You must maintain the records as specified in § 60.5420(c)(2).

* * * * *

(d) To achieve initial compliance with 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 § 60.5420(c)(4)(ii) of your determination that the use of a pneumatic controller affected facility with a bleed rate greater than 6 standard cubic feet of gas per hour is required as specified in § 60.5390(a).

(2) You own or operate a pneumatic controller affected facility located at a natural gas processing plant and your pneumatic controller is driven by a gas other than natural gas and therefore emits zero natural gas.

(3) * * *

(4) You must tag each new pneumatic controller affected facility according to the requirements of § 60.5390(b)(2) or (c)(2).

* * * * *

(e) [Reserved]

* * * * *

(h) For each storage vessel affected facility that is subject to § 60.5395(d), you must comply with paragraphs (h)(1) through (5) of this section.

(1) You must determine the VOC emission rate within 30 days after startup. You must use good engineering practices to minimize emissions during the 30-day period.

(2) You must reduce VOC emissions by 95.0 percent or greater within 60 days after startup or by April 15, 2014, whichever is later.

(3) If you use a control device to reduce emissions, or if you route emissions to a flow line, you must demonstrate initial compliance by meeting the requirements in paragraphs (h)(3)(i) and (ii) of this section. For a Group 1 storage vessel affected facility, you must demonstrate initial compliance within 30 days after an event (as provided in § 60.5395(b)) or by April 15, 2014, whichever is later. For a Group 2 storage vessel affected facility, you must demonstrate initial compliance within 60 days after startup or by April 15, 2014, whichever is later.

(i) You must equip the storage vessel with a cover that meets the requirements of § 60.5411(b) and is connected through a closed vent system that meets the requirements of § 60.5411(c).

(ii) You must route the closed vent system to a control device that meets the conditions specified in § 60.5412(c) and (d) or to a flow line, as defined in § 60.5430.

(4) You must submit the information required for your storage vessel affected facility in paragraphs (h)(4)(i) through (iii) of this section in the initial annual report required in § 60.5420(b).

(i) The results of the emissions determination conducted under § 60.5395(b) or (c), as applicable, and the methodology used to determine emissions.

(ii) A statement that you have met the requirements of paragraph (h)(2) of this section.

(iii) A statement that you have met the emissions standards in § 60.5395(d).

(5) You must maintain the records required for your storage vessel affected facility, as specified in § 60.5420(c)(5) for each storage vessel affected facility.

(i) For each Group 1 storage vessel, you must submit a notification identifying each storage vessel, including its location by October 15, 2013. If you have an event that results in VOC emissions from the Group 1 storage vessel equal to or greater than 6 tpy after April 12, 2013, as specified in § 60.5395(b), you must comply with paragraph (h) of this section.

■ 7. Section 60.5411 is amended by:
■ a. Revising the section heading;
■ b. Revising paragraph (a) introductory text;
■ c. Revising paragraph (a)(1);
■ d. Revising paragraph (a)(3)(i)(A);
■ e. Revising paragraph (b) introductory text;
■ f. Revising paragraph (b)(1);
■ g. Revising paragraph (b)(2)(iv);
■ h. Adding paragraph (b)(3); and
■ i. Adding paragraph (c).

The revisions and additions 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) *Closed vent system requirements for centrifugal compressor wet seal degassing systems.* (1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the wet seal fluid degassing system to a control device that meets the requirements specified in § 60.5412(a) through (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 flow line to the atmosphere that is capable of taking periodic readings as specified in § 60.5416(a)(4) and sounds an alarm when the bypass device is open such that the stream is being, or could be, diverted away from the control device to the atmosphere.

* * * * *

(b) *Cover requirements for storage vessels and centrifugal compressor wet seal degassing systems.* (1) The cover and all openings on the cover (*e.g.,* access hatches, sampling ports, pressure relief valves and gauge wells) shall form a continuous barrier over the entire surface area of the liquid in the storage vessel or wet seal fluid degassing system.

(2) * * *

(iv) To vent liquids, gases, or fumes from the unit through a closed-vent system to a control device designed and operated in accordance with the requirements of paragraph (a) of this section or to a flow line, as defined in § 60.5430.

(3) Each storage vessel thief hatch shall be weighted and properly seated. 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 flow line.* (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 § 60.5412(c) and (d), or to a flow line, as defined in § 60.5430.

(2) You must design and operate the 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 flow line, as defined in § 60.5430.

(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 flow line to the atmosphere that sounds an alarm when the bypass device is open such that the stream is being, or could be, diverted away from the control device or flow line to the atmosphere.

(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.

■ 8. Section 60.5412 is amended by:

■ a. Revising paragraph (a) introductory text;

■ b. Revising paragraph (a)(1) introductory text;

■ c. Revising paragraph (a)(2);

■ d. Revising paragraph (b);

■ e. Revising paragraph (c) introductory text;

■ f. Revising paragraph (c)(1); and

■ g. Adding paragraph (d).

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) Each control device used to meet the emission reduction standard in § 60.5380(a)(1) for your centrifugal compressor affected facility, must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative, for a centrifugal compressor affected facility, you may install a control device model tested under § 60.5413(d), which meets the criteria in § 60.5413(d)(11) and § 60.5413(e).

(1) Each enclosed 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.

* * * * *

(2) Each vapor recovery device (e.g., carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413. 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 § 60.5413(c).

* * * * *

(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 § 60.5380(a), 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 § 60.5417(a) through (g), you must demonstrate compliance according to the requirements of § 60.5415(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 § 60.5413(c)(2) or (3) or according to the design analysis 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 § 60.5420(c)(10) and (13).

* * * * *

(d) Each control device used to meet the emission reduction standard in § 60.5395(d) for your storage vessel affected facility, must be installed according to paragraphs (d)(1) through (3) of this section, as applicable. As an alternative, you may install a control device model tested under § 60.5413(d), which meets the criteria in § 60.5413(d)(11) and § 60.5413(e).

(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. You must follow the requirements in paragraphs (d)(1)(i) through (iii) of this section.

(i) Ensure that each enclosed combustion device is maintained in a leak free condition.

(ii) Install and operate a continuous burning pilot flame.

(iii) Operate the enclosed combustion device with no visible emissions, except for periods not to exceed a total of one minute during any 15 minute period. A visible emissions test using section 11 of EPA Method 22, 40 CFR part 60, Appendix A, 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 on-site for inspection. Following return to operation from maintenance or repair activity, each device must pass a Method 22, 40 CFR part 60, Appendix A, visual observation as described in this paragraph.

(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 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.

■ 9. Section 60.5413 is amended by:

■ a. Revising the introductory text;

■ b. Revising paragraph (a)(7);

■ c. Revising paragraph (d); and

■ d. Adding paragraph (e).

■ The revisions and addition 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?

This section applies to the performance testing of control devices used to demonstrate compliance with the emissions standards for your centrifugal compressor affected facility. You must demonstrate that a control device achieves the performance requirements of § 60.5412(a) using the performance test methods and procedures specified in this section. For condensers, you may use a design analysis as specified in paragraph (c) of this section in lieu of complying with paragraph (b) of this section. In addition, this section contains the requirements for enclosed combustion device performance tests conducted by the manufacturer applicable to both storage vessel and centrifugal compressor affected facilities.

(a) * * *

(7) A control device whose model can be demonstrated to meet the performance requirements of § 60.5412(a) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

* * * * *

(d) *Performance testing for combustion control devices—manufacturers' performance test.* (1) This paragraph applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer must demonstrate that a specific model of control device achieves the performance requirements in paragraph (d)(11) of this section by conducting a performance test as specified in paragraphs (d)(2) through (10) of this section. You must submit a test report for each combustion control device in accordance with the requirements in paragraph (d)(12) of this section.

(2) Performance testing must consist of three one-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. Propene (propylene) gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90–100 percent of maximum design rate (fixed rate).

(ii) 70–100–70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10–15 minute time range, incrementally ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30–70–30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10–15 minute time range, incrementally ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0–30–0 percent (ramp up, ramp down). Begin the test at the minimum firing rate. During the first 5 minutes, incrementally ramp the firing rate to 30 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10–15 minute time range, incrementally ramp back down to the minimum firing rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures must be tested simultaneously and with all burners operational. Results must be reported for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data must be collected continuously throughout the performance test using an electronic Data Acquisition System. A graphic presentation or strip chart of the control device operating data and emissions test data must be included in the test report in accordance with paragraph (d)(12) of this section. Inlet fuel meter data may be manually recorded provided that all inlet fuel data readings are included in the final report.

(4) Inlet testing must be conducted as specified in paragraphs (d)(4)(i) through (ii) of this section.

(i) The inlet gas flow metering system must be located in accordance with Method 2A, 40 CFR part 60, appendix A–1, (or other approved procedure) to measure inlet gas flow rate at the control device inlet location. You must position the fitting for filling fuel sample containers a minimum of eight pipe diameters upstream of any inlet gas flow monitoring meter.

(ii) Inlet flow rate must be determined using Method 2A, 40 CFR part 60, appendix A–1. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute test.

(5) Inlet gas sampling must be conducted as specified in paragraphs (d)(5)(i) through (ii) of this section.

(i) At the inlet gas sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 3-hour period. Filling must be conducted as specified in paragraphs (d)(5)(i)(A) through (C) of this section.

(A) Open the canister sampling valve at the beginning of each test run, and close the canister at the end of each test run.

(B) Fill one canister across the three test runs such that one composite fuel sample exists for each test condition.

(C) Label the canisters individually and record sample information on a chain of custody form.

(ii) Analyze each inlet gas sample using the methods in paragraphs (d)(5)(ii)(A) through (C) of this section. You must include the results in the test report required by paragraph (d)(12) of this section.

(A) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945–03.

(B) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945–03.

(C) Higher heating value using ASTM D3588–98 or ASTM D4891

89.

(6) Outlet testing must be conducted in accordance with the criteria in paragraphs (d)(6)(i) through (v) of this section.

(i) Sample and flow rate must be measured in accordance with paragraphs (d)(6)(i)(A) through (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, 40 CFR part 60, appendix A–1 for determining flow measurement traverse point location, and Method 2, 40 CFR part 60, appendix A–1 for measuring duct velocity. If low flow conditions are encountered (*i.e.*, velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer must be used to obtain an accurate flow profile.

(ii) Molecular weight and excess air must be determined as specified in paragraph (d)(7) of this section.

(iii) Carbon monoxide must be determined as specified in paragraph (d)(8) of this section.

(iv) THC must be determined as specified in paragraph (d)(9) of this section.

(v) Visible emissions must be determined as specified in paragraph (d)(10) of this section.

(7) Molecular weight and excess air determination must be performed as specified in paragraphs (d)(7)(i) through (iii) of this section.

(i) An integrated bag sample must be collected during the Method 4, 40 CFR part 60, appendix A–3, moisture test following the procedure specified in (d)(7)(i)(A) through (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) through (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, 40 CFR part 60, appendix A, 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, 40 CFR part 60, appendix A–3. Traverse both ports with the Method 4, 40 CFR part 60, appendix A–3, sampling train during each test run. Ambient air must not be introduced into the Method 3C, 40 CFR part 60, appendix A–2, integrated bag sample during the port change.

(iii) Excess air must be determined using resultant data from the EPA Method 3C tests and EPA Method 3B, 40 CFR part 60, appendix A, equation 3B–1.

(8) Carbon monoxide must be determined using Method 10, 40 CFR part 60, appendix A. Run the test simultaneously with Method 25A, 40 CFR part 60, appendix A–7 using the same sampling points. An instrument range of 0–10 parts per million by volume-dry (ppmvd) is recommended.

(9) Total hydrocarbon determination must be performed as specified by in paragraphs (d)(9)(i) through (vii) of this section.

(i) Conduct THC sampling using Method 25A, 40 CFR part 60, appendix A–7, except that the option for locating the probe in the center 10 percent of the stack is not allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during each test run.

(ii) A valid test must consist of three Method 25A, 40 CFR part 60, appendix A–7, tests, each no less than 60 minutes in duration.

(iii) A 0–10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0–30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases must be propane in air and be certified through EPA Protocol 1—''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, as amended August 25, 1999, EPA–600/R–97/121(or more recent if updated since 1999).

(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, 40 CFR part 60, appendix A–2. You must use the following equation for this diluent concentration correction:

$$Ccorr = Cmeas\left(\frac{3}{CO_{2meas}}\right)$$

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, 40 CFR part 60, appendix A. 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) Method 22, 40 CFR part 60, appendix A, results under paragraph (d)(10) of this section with no indication of visible emissions.

(B) Average Method 25A, 40 CFR part 60, appendix A, results under paragraph (d)(9) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2.

(C) Average CO emissions determined under paragraph (d)(8) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO_2.

(D) Excess combustion air determined under paragraph (d)(7) of this section equal to or greater than 150 percent.

(ii) The manufacturer must determine a maximum inlet gas flow rate which must not be exceeded for each control device model to achieve the criteria in paragraph (d)(11)(iii) of this section. The maximum inlet gas flow rate must be included in the test report required by paragraph (d)(12) of this section.

(iii) A control device meeting the criteria in paragraph (d)(11)(i)(A) through (D) of this section must demonstrate a destruction efficiency of 95 percent for VOC regulated under this subpart.

(12) The owner or operator of a combustion control device model tested under this section must submit the information listed in paragraphs (d)(12)(i) through (vi) in the test report required by this section.

(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 combustion air range.

(G) Flame arrestor(s).

(H) Burner manifold.

(I) Pilot flame indicator.

(J) Pilot flame design fuel and calculated or measured fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) The test report must include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, strip charts, or other graphic presentations of the data annotated with test times and calibration values.

(e) *Continuous compliance for combustion control devices tested by the manufacturer in accordance with paragraph (d) of this section.* This paragraph applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (d) of this section. Owners or operators must demonstrate that a control device achieves the performance requirements in (d)(11) of this section by installing a device tested under paragraph (d) of this section and complying with the criteria specified in paragraphs (e)(1) through (6) of this section.

(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 2 minutes during any hour. A visible emissions test using Method 22, 40 CFR part 60, appendix A, must be performed each calendar quarter. The observation period must be 1 hour and must be conducted according to EPA Method 22, 40 CFR part 60, appendix A.

(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 on site for inspection.

(5) Following return to operation from maintenance or repair activity, each device must pass an EPA Method 22, 40 CFR part 60, Appendix A, visual observation as described in paragraph (e)(3) of this section.

(6) If the owner or operator operates a combustion control device model tested under this section, an electronic copy of the performance test results required by this section shall be submitted via email to *Oil_and_Gas_PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following Web site: *epa.gov/airquality/oilandgas/*.

■ 10. Section 60.5415 is amended by:

■ a. Revising paragraph (b) introductory text;

■ b. Revising paragraph (b)(2);

■ c. Revising paragraph (e) introductory text;

■ d. Removing and reserving paragraphs (e)(1) and (2);

■ e. Adding paragraph (e)(3); and

■ f. Revising paragraph (h)(1) introductory text.

The revisions and addition 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) For each centrifugal compressor affected facility, you must demonstrate continuous compliance according to paragraph (b)(1) through (3) of this section.

* * * * *

(2) For each control device used to reduce emissions, you must demonstrate continuous compliance with the performance requirements of § 60.5412(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 § 60.5412(a)(2), you must 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, as required in § 60.5420(b), following the change.

(i) You must operate below (or above) the site specific maximum (or minimum) parameter value established according to the requirements of § 60.5417(f)(1).

(ii) You must calculate the daily average of the applicable monitored parameter in accordance with § 60.5417(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 § 60.5413(d), compliance with the operating parameter limit is achieved when the criteria in § 60.5413(e) are met.

(iv) You must operate the continuous monitoring system required in § 60.5417 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 § 60.5412(a) and you demonstrate compliance using the test procedures specified in § 60.5413(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 2 minutes during any hour. A visible emissions test using Method 22, 40 CFR part 60, appendix A, must be performed each calendar quarter. The observation period must be 1 hour and must be conducted according to EPA Method 22, 40 CFR part 60, appendix A.

(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 on site for inspection.

(D) Following return to operation from maintenance or repair activity, each device must pass a Method 22, 40 CFR part 60, Appendix A, 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 § 60.5412(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 § 60.5417(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with § 60.5417(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 § 60.5370, 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 dates. 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 § 60.5370, 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.

* * * * *

(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 flow line to meet the requirement of § 60.5395(d)(1).

(1) [Reserved]

(2) [Reserved]

(3) For each storage vessel affected facility subject to § 60.5395(d)(1), you must comply with paragraphs (e)(3)(i) and (ii) of this section.

(i) You must reduce VOC emissions by 95.0 percent or greater.

(ii) You must demonstrate continuous compliance with the performance requirements of § 60.5412(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 § 60.5416(c) for each cover and closed vent system.

(B) You must comply with § 60.5417(h) for each control device.

(C) Each closed vent system that routes emissions to a flow line, as defined in § 60.5430, must be operational 95 percent of the year or greater.

* * * * *

(h) * * *

(1) To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in § 60.5415(h)(2), and must prove by a preponderance of evidence that:

* * * * *

■ 11. Section 60.5416 is amended by:
■ a. Revising the introductory text;
■ b. Revising paragraph (a) introductory text;
■ c. Revising paragraph (a)(1)(ii);
■ d. Revising paragraph (a)(2)(iii);
■ e. Revising paragraph (a)(3)(ii);
■ f. Revising paragraph (b) introductory text,
■ g. Revising paragraph (b)(9) introductory text;
■ h. Revising paragraph (b)(11); and
■ i. Adding paragraph (c).

The revisions and addition 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 facility?

For each closed vent system or cover at your storage vessel or centrifugal compressor affected facility, 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 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) * * *

(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 § 60.5420(c)(6).

(2) * * *

(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 § 60.5420(c)(6).

(3) * * *

(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 § 60.5420(c)(7).

* * * * *

(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 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.

* * * * *

(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.

* * * * *

(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.

* * * * *

(c) *Cover and closed vent system inspections for storage vessel affected facilities.* If you install a control device or route emissions to a flow line, 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 (8) 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 § 60.5420(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 § 60.5420(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 § 60.5411, you must meet the requirements of paragraphs (c)(3)(i) or (ii) of this section.

(i) Set the flow indicator to sound an alarm at the inlet to the bypass device when the stream is being diverted 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 § 60.5420(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.

(8) *Records.* Records shall be maintained as specified in this section and in § 60.5420(c)(12).

■ 12. Section 60.5417 is amended by:
■ a. Revising paragraph (a);
■ b. Revising paragraph (b) introductory text;
■ c. Revising paragraph (c) introductory text;
■ d. Revising paragraphs (d)(1)(viii)(A) and (B);
■ e. Revising paragraph (d)(2);
■ f. Revising paragraph (f)(1)(iii);
■ g. Revising paragraph (g)(6)(ii); and
■ h. Adding paragraph (h).

The revisions and addition read as follows:

§ 60.5417 What are the continuous control device monitoring requirements for my 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 § 60.5380, 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 § 60.5412(a)(3), you are exempt from the requirements of paragraphs (e) and (f) of this section.

(b) You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.

* * * * *

(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.

* * * * *

(d) * * *

(1) * * *

(viii) * * *

(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. The flow rate at the inlet to the combustion device must not exceed the maximum or minimum flow rate determined by the manufacturer.

(B) A monitoring device that continuously indicates the presence of the pilot flame while emissions are routed to the control device.

(2) An organic monitoring device equipped with a continuous recorder that measures the concentration level of organic compounds in the exhaust vent stream from the control device. The monitor must meet the requirements of Performance Specification 8 or 9 of 40 CFR part 60, appendix B. You must install, calibrate, and maintain the monitor according to the manufacturer's specifications.

* * * * *

(f) * * *

(1) * * *

(iii) If you operate a control device where the performance test requirement was met under § 60.5413(d) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412(a), then your control device inlet gas flow rate must not exceed the maximum or minimum inlet gas flow rate determined by the manufacturer.

* * * * *

(g) * * *

(6) * * *

(ii) Failure of the quarterly visible emissions test conducted under § 60.5413(e)(3) occurs.

(h) For each control device used to comply with the emission reduction standard in § 60.5395(d)(1) for your storage vessel affected facility, you must demonstrate continuous compliance according to paragraphs (h)(1) through (h)(3) of this section. You are exempt from the requirements of this paragraph if you install a control device model tested in accordance with § 60.5413(d)(2) through (10), which meets the criteria in § 60.5413(d)(11), the reporting requirement in § 60.5413(d)(12), and meet the continuous compliance requirement in § 60.5413(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, 40 CFR part 60, Appendix A. The observation period shall be 15 minutes. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period.

(iii) Conduct olfactory, visual and auditory inspections of all equipment associated with the combustion device to ensure system integrity.

(iv) For any absence of pilot flame, or other indication of smoking or improper equipment operation (*e.g.,* visual, audible, or olfactory), you must ensure the equipment is returned to proper operation as soon as practicable after the event occurs. At a minimum, you must perform the procedures specified in paragraphs (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 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 maintained onsite as specified in § 60.5420(c)(14).

■ 13. Section 60.5420 is amended by:

■ a. Revising paragraph (a) introductory text;

■ b. Revising paragraph (a)(1);

■ c. Adding paragraph (a)(3);

■ d. Revising paragraph (b) introductory text;

■ e. Revising paragraph (b)(3)(iii);

■ f. Revising paragraph (b)(5) introductory text;

■ g. Revising paragraph (b)(5)(i);

■ h. Revising paragraphs (b)(6)(i) and (ii);

■ i. Revising paragraphs (b)(7)(i) and (ii);

■ j. Adding paragraph (b)(8);

■ k. Revising paragraph (c) introductory text;

■ l. Revising paragraph (c)(1)(v);

■ m. Revising paragraph (c)(5) introductory text;

■ n. Revising paragraph (c)(5)(ii);

■ o. Adding paragraph (c)(5)(v);

■ p. Revising paragraphs (c)(6) through (11); and

■ q. Adding paragraphs (c)(12) through (14).

The revisions and additions read as follows:

§ 60.5420 What are my notification, reporting, and recordkeeping requirements?

(a) You must submit the notifications according to paragraphs (a)(1) through (3) of this section if you own or operate one or more of the affected facilities specified in § 60.5365 that was constructed, modified, or reconstructed during the reporting period.

(1) If you own or operate a gas well, pneumatic controller, centrifugal compressor, reciprocating compressor or storage vessel affected facility you are not required to submit the notifications required in § 60.7(a)(1), (3), and (4).

* * * * *

(3) You must submit a notification identifying each Group 1 storage vessel by October 15, 2013. The notification must contain the location of the storage vessel, 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.

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (6) of this section to the Administrator and performance test reports as specified in paragraph (b)(7) or (8) 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 § 60.5410. 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 (6) 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.

* * * * *

(3) * * *

(iii) If required to comply with § 60.5380(a)(1), the records specified in paragraphs (c)(6) through (14) of this section.

* * * * *

(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 § 60.5390(b)(2) or § 60.5390(c)(2).

* * * * *

(6) * * *

(i) An identification, including the location, of each storage vessel affected facility constructed, modified or reconstructed 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 the requirements in § 60.5395(b) or (c) or as required in § 60.5395(d)(2).

* * * * *

(7) (i) Within 60 days after the date of completing each performance test (see § 60.8 of this part) as required by this subpart, except testing conducted by the manufacturer as specified in § 60.5413(d), you must submit the results of the performance tests required by this subpart to the EPA as follows. You must use the latest version of the EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*) existing at the time of the performance test to generate a submission package file, which documents the performance test. You must then submit the file generated by the ERT through the EPA's Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed by logging in to the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). Only data collected using test methods supported by the ERT as listed on the ERT Web site are subject to this requirement for submitting reports electronically. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test to the Administrator at the appropriate address listed in § 60.4.

(ii) All reports, except as specified in paragraph (b)(8) of this section, required by this subpart not subject to the requirements in paragraph (a)(2)(i) of this section must be sent to the Administrator at the appropriate address listed in § 60.4 of this part. The Administrator or the delegated authority may request a report in any form suitable for the specific case (*e.g.,* by commonly used electronic media such as Excel spreadsheet, on CD or hard copy).

(8) For enclosed combustors tested by the manufacturer in accordance with § 60.5413(d), an electronic copy of the performance test results required by § 60.5413(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/.*

(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 must be maintained for at least 5 years.

(1) * * *

(v) For each gas well affected facility required to comply with both § 60.5375(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 § 60.5410(a)(4).

* * * * *

(5) Except as specified in paragraph (c)(5)(v) of this section, for each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) through (iv) of this section.

* * * * *

(ii) Records of each VOC emissions determination for each storage vessel affected facility required under § 60.5395(b), (c) and (d)(2), as applicable, including identification of the model or calculation methodology used to calculate the VOC emission rate.

* * * * *

(v) You must maintain records of the identification and location of each Group 1 storage vessel. If you have an event, as specified in § 60.5395(b)(2), that could reasonably be expected to increase VOC emissions from your Group 1 storage vessel, you must maintain records of the VOC emissions rate determination.

(6) Records of each closed vent system inspection required under § 60.5416(a)(1) for centrifugal compressors or § 60.5416(c)(1) for storage vessels.

(7) A record of each cover inspection required under § 60.5416(a)(3) for centrifugal compressors or § 60.5416(c)(2) for storage vessels.

(8) If you are subject to the bypass requirements of § 60.5416(a)(4) for centrifugal compressors or § 60.5416(c)(3) for storage vessels, a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

(9) For each closed vent system used to comply with this subpart that must operate with no detectable emissions, a record of the monitoring conducted in accordance with § 60.5416(b).

(10) For each centrifugal compressor affected facility, records of the schedule for carbon replacement (as determined by the design analysis requirements of § 60.5413(c)(2) or (3)) and records of each carbon replacement as specified in § 60.5412(c)(1).

(11) For each centrifugal compressor subject to the control device requirements of § 60.5412(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 cover and closed vent system installed on storage vessel affected facilities used to comply with § 60.5416(c), a record of all inspections.

(13) 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 § 60.5412(d)(2)) and records of each carbon replacement as specified in § 60.5412(c)(1).

(14) For each storage vessel affected facility subject to the control device requirements of § 60.5412(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 § 60.5417(h). You must maintain records of EPA Method 22, 40 CFR part 60, Appendix A, 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, 40 CFR part 60, Appendix A. Manufacturer's records must be maintained onsite.

■ 14. Section 60.5430 is amended by:

■ a. Adding, in alphabetical order, definitions for the terms ''condensate,'' ''Group 1 storage vessel,'' ''Group 2 storage vessel,'' ''intermediate hydrocarbon liquid'' and ''produced water;'' and

■ b. Revising the definition for ''storage vessel'' to read as follows:

§ 60.5430 What definitions apply to this subpart?

* * * * *

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.

* * * * *

Group 1 storage vessel means a storage vessel, as defined in this section, that is constructed, modified or reconstructed on or after August 23, 2011, and before April 12, 2013.

Group 2 storage vessel means a storage vessel, as defined in this section, that is constructed, modified or reconstructed on or after April 12, 2013.

* * * * *

Intermediate hydrocarbon liquid means any naturally occurring, unrefined petroleum liquid.

* * * * *

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.

* * * * *

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. 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 § 60.5420(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 since the original vessel was first located at the site.

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

(3) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

* * * * *

■ 15. Appendix to subpart OOOO of part 60 is amended by revising Tables 1 and 2 to read as follows:

TABLE 1 TO SUBPART OOOO 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 OOOO 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.

* * * * *

[FR Doc. 2013–07873 Filed 4–11–13; 8:45 am]

BILLING CODE 6560–50–P