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40 CFR Part 60
Oil and Natural Gas Sector: Reconsideration of Additional Provisions of New Source Performance Standards; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2010–0505, FRL–9913–40–OAR]

RIN 2060–AS01

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

AGENCY: Environmental Protection Agency.

ACTION: Proposed rule; Notice of Public Hearing.

SUMMARY: On August 16, 2012, the Environmental Protection Agency (EPA) published final new source performance standards for the oil and natural gas sector. The Administrator received petitions for administrative reconsideration of certain aspects of the standards. Among issues raised in the petitions were time-critical issues related to certain storage vessel provisions and well completion provisions. On September 23, 2013, the EPA published final amendments as a result of reconsideration of issues related to implementation of the storage vessel provisions. Following that action, the Administrator again received petitions for administrative reconsideration pertaining to the storage vessel provisions. In this notice, the EPA is announcing proposed amendments and clarifications as a result of reconsideration of certain issues related to well completions and additional issues pertaining to storage vessels. The proposed amendments also address other issues raised for reconsideration and make technical corrections and amendments to further clarify the rule.

DATES: *Comments.* Comments must be received on or before August 18, 2014, unless a public hearing is requested by July 22, 2014. If a hearing is requested on this proposed rule, written comments must be received by September 2, 2014.

Public Hearing. If anyone contacts the EPA requesting a public hearing by July 22, 2014 we will hold a public hearing on August 1, 2014.

If a public hearing is requested by July 22, 2014, it will be held on August 1, 2014 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 Virginia Hunt at (919) 541–0832, or at *hunt.virginia@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 July 30, 2014. 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 July 22, 2014, 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 these hearings are being held at U.S. government facilities, individuals planning to attend the hearing should be prepared to show valid picture identification (e.g., driver's license or government-issued ID) to the security staff in order to gain access to the meeting room. Please note that the REAL ID Act, passed by Congress in 2005, established new requirements for entering federal facilities. These requirements will take effect July 21, 2014. If your driver's license is issued by Alaska, American Samoa, Arizona, Kentucky, Louisiana, Maine, Massachusetts, Minnesota, Montana, New York, Oklahoma or Washington State, you must present an additional form of identification to enter the federal buildings where the public hearings will be held. Acceptable alternative forms of identification include: Federal employee badges, passports, enhanced driver's licenses and military identification cards. 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 August 1, 2014, written comments on the proposed rule must be postmarked by September 2, 2014. Commenters should notify Ms. Hunt 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. 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 July 22, 2014.

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

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the online instructions for submitting comments.
- *Email: A-and-R-Docket@epa.gov.* Include Docket ID No. EPA–HQ–OAR–2010–0505 in the subject line of the message.
- *Fax:* (202) 566–9744, Attention Docket ID No. EPA–HQ–OAR–2010–0505.
- *Mail:* Environmental Protection Agency, EPA Docket Center (EPA/DC), Mail Code 28221T, Attention Docket ID No. EPA–HQ–OAR–2010–0505, 1200 Pennsylvania Avenue NW., Washington, DC 20460. Please include a total of two copies. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), Attn: Desk Officer for EPA, 725 17th Street NW., Washington, DC 20503
- *Hand/Courier Delivery:* EPA Docket Center, Room 3334, EPA WJC West Building, 1301 Constitution Avenue NW., Washington, DC 20004, Attention Docket ID No. EPA–HQ–OAR–2010–0505. Such deliveries are only accepted during the Docket's normal hours of operation, 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 WJC 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:

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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
BSER Best System of Emissions Reduction
CAA Clean Air Act
CFR Code of Federal Regulations
EPA Environmental Protection Agency
Mcf Thousand Cubic Feet
NESHAP National Emissions Standards for Hazardous Air Pollutants
NSPS New Source Performance Standards
NTTAA National Technology Transfer and Advancement Act
OAQPS Office of Air Quality Planning and Standards
OMB Office of Management and Budget
OVA Olfactory, Visual and Auditory
PTE Potential to Emit
RFA Regulatory Flexibility Act
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 proposed rule apply to me?

Categories and entities potentially affected by today's *proposed rule* 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.

TABLE 1—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS ACTION—Continued

Category	NAICS code [1]	Examples of regulated entities
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 (NSPS) 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 World Wide Web through the TTN. Following signature, a copy of this 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/airquality/oilandgas/actions.html.*

III. Background

On August 16, 2012, the EPA published the Oil and Natural Gas Sector NSPS (40 CFR part 60 subpart OOOO) in the **Federal Register** at 77 FR 49490. Following promulgation of the final rule, the Administrator received petitions for administrative reconsideration of several provisions of the NSPS pursuant to Clean Air Act (CAA) section 307(d)(7)(B). Copies of the petitions are provided in rulemaking docket EPA–HQ–OAR–2010–0505. On September 23, 2013, the EPA published final amendments primarily related to implementation of the storage vessel provisions. In the petitions for reconsideration of the 2012 final rule, petitioners raised several issues regarding clarification of the well completion provisions, some of which have a compliance deadline of January 1, 2015. In addition, the Administrator received petitions for reconsideration of several provisions of the 2013 storage vessel implementation amendments.

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) Provisions for well completions that clarify existing requirements for handling of flowback gases and liquids; (2) definition of ''low pressure gas well'' ; (3) requirements pertaining to determining the potential emission of storage vessels that employ vapor recovery; (4) requirements for thief hatches; (5) provisions for storage vessels that are removed from service; (6) routing of emissions from reciprocating compressor rod packing to a process; (7) leak detection requirements at small natural gas processing plants and natural gas processing plants located on the Alaskan North Slope; (8) equipment subject to leak detection requirements under the NSPS; and (9) definition of ''responsible official'' for compliance certification purposes. In addition, we are proposing to remove the affirmative defense provisions from the startup, shutdown and malfunction provisions of the 2012 NSPS. Finally, we are proposing to correct technical errors in the 2012 NSPS.

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 any 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 impact emission reductions.

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 well completion and storage vessel provisions that have been raised by different stakeholders through several administrative petitions for reconsideration of the 2012 NSPS and the 2013 storage vessel amendments to the NSPS. The EPA is proposing to amend the NSPS to address these issues.

We are proposing to amend the standards for gas well affected facilities to provide greater clarity concerning what owners and operators must do during well completion operations, especially the provisions for reduced emissions completions which have a compliance date of January 1, 2015. While the 2012 NSPS focused mainly on handling of flowback emissions, we did not provide extensive detail concerning requirements for handling of liquids during the well completion operation. In this action, we are proposing to identify three distinct stages of a well completion operation and specific requirements for handling of gases and liquids for each stage. The ''initial flowback stage'' begins with the onset of flowback following hydraulic fracturing or refracturing and ends when there is sufficient gas present in the flowback for a separator to operate. At that time, the operator must direct the flowback to the separator, and the ''separation flowback stage'' begins. It is at this stage where recovery of the gas begins, unless the gas is unsuitable for entering the flow line, or infrastructure to convey the gas to market is not available, in which case the gas is required to be combusted unless combustion poses a safety hazard. Once the flowback volume has subsided and stabilized such that the well is producing gas continuously to the flow line or is shut in, and any crude oil, condensate and produced water in the flowback can be separated, the ''production stage'' begins and continues as ongoing production of the well. At that time, the separated and recovered crude oil, condensate and produced water must be routed to storage vessels. At the beginning of the production stage, the operator must begin the 30-day process of estimating storage vessel volatile organic compound (VOC) potential to emit (PTE) and must control emissions no later than 60 days after the beginning of the production stage. Beginning with the production stage, the rule prohibits venting or flaring of gas.

We are re-proposing for comment the definition of ''low pressure gas well,'' as related to the well completion provisions. We added this definition in the 2012 NSPS in response to public comments. Petitioners asserted that the definition is unnecessarily complicated and would pose difficulty for smaller operators. The petitioners provided a very straightforward alternative on which we are also soliciting comment.

We are proposing several amendments related to the storage vessel provisions of the NSPS. First, we are proposing to amend the provisions for determining PTE for storage vessels with vapor recovery to clarify that the provisions allowing sources to exclude emissions captured through vapor recovery if certain specified control requirements are met do not apply to storage vessels whose PTE is limited to below the 6 tons per year (tpy) applicability threshold under a legally and practically enforceable permit or other limitation under federal, state or tribal authority. We are also proposing to amend the storage vessel closed cover requirements to allow other mechanisms besides weighted lid thief hatches to ensure that the thief hatch lid remains properly seated. In addition, we are proposing to amend slightly the requirements for storage vessels to clarify notification and other requirements under the NSPS for storage vessels that are removed from service.

We are proposing to amend the requirements for reciprocating compressors to add a third alternative to the two existing work practice options for controlling emissions from rod packing venting. We are proposing a third alternative that would be to route emissions from the rod packing through a closed vent system to a process.

We are proposing two amendments to the equipment leaks requirements for natural gas processing plants. One is to correct an inadvertent omission we made in the 2012 NSPS concerning an exemption from routine leak detection in small gas processing plants and gas processing plants located on the Alaskan North Slope. In the 2012 NSPS, we inadvertently failed to include connectors in the list of equipment under this exemption. In addition, we are proposing to amend the definition of ''equipment'' to clarify that the term, as used in relation to the equipment leaks requirements under the NSPS, refers only to equipment at onshore natural gas processing plants.

We are proposing to amend the definition of ''responsible official'' that is used in conjunction with the compliance certification provisions of the 2012 NSPS. We are proposing to amend the definition of ''responsible official'' to provide for delegation of authority after advance notification rather than after approval, which is currently required for delegation to authorities responsible for facilities that employ 250 or fewer employees and have less than $25 million gross annual sales or expenditures (in second quarter 1980 dollars). Requirements for delegation to representatives responsible for one or more facilities that employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars) are unchanged from the 2012 NSPS (i.e., there is no advance notification or approval required for such delegations).

Finally, we are proposing to remove the ''affirmative defense'' provisions from the startup, shutdown and malfunction provisions of the 2012 NSPS. We are also proposing to correct technical errors in the 2012 NSPS. Details and rationale for all the above proposed amendments are presented in section VI below.

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 2012 NSPS final action and 2013 storage vessel amendments. The following sections discuss the issues that the EPA is addressing in this action and how the EPA proposes to resolve the issues.

A. Well Completions

Several petitioners raised issues with regard to the well completion provisions in the 2012 NSPS, including handling of flowback gases and liquids and definition of ''low pressure well.'' While the 2012 NSPS focused mainly on handling of flowback gases, we did not provide extensive detail concerning requirements for handling of liquids during the various stages of well completion. The proposed amendments to the regulatory text discussed below provide clarity concerning what owners and operators must do during completion operations, and the proposed amendments to the requirements would maintain the same level of reduction as the 2012 NSPS.

1. Handling of Flowback Gases and Liquids

The petitioners asserted that the rule is unclear with regard to requirements in § 60.5375 for handling of gases and liquids during flowback and that, as written, compliance with the existing language cannot be achieved. Specifically, petitioners asserted that § 60.5375(a)(1) which states ''(F)or the duration of flowback, route the recovered liquids into one or more storage vessels . . . and route the recovered gas into a gas flow line or collection system . . . with no direct release to the atmosphere'' could be interpreted to prohibit venting of gases at any time during the flowback period. According to petitioners, at the beginning of the flowback period, the flowback consists initially of water, fracturing fluids and proppant (sand) with no gas present. At some point, sporadic slugs of gas begin to appear in the flowback in increasing amounts until enough gas is present to approach flammability and to enable a separator to function. Petitioners explained that operators usually locate a monitor on the vessel receiving the initial flowback to sense the gas concentration. When the gas concentration approaches flammability, the flowback is then directed to a separator. For a separator to function, enough gas must be flowing to maintain a gaseous phase and one or more liquid phases within the separator. In addition, petitioners explained that the requirement to ''route the recovered liquids into one or more storage vessels'' is not feasible because of the composition and high volumetric flow of the initial flowback that necessitate using open top tanks or a pit for this purpose. As explained by the petitioners, this initial high volume liquid flowback carries with it sand and debris that can be removed relatively easily from open top tanks or that can settle to the bottom of lined pits. The petitioners also explained that removal of sand and debris from a closed top tank is extremely difficult and must be performed manually. Petitioners further noted that, because temporary tanks are excluded from the definition of ''storage vessel,'' such temporary tanks as fracture tanks (frac tanks) cannot be used to comply with requirements of the 2012 NSPS.

In the EPA's clarification letter to the American Petroleum Institute (API),[1 2] we explained that it was not the EPA's intent to prohibit venting of flowback gases throughout the entire flowback period and that we understood that there were periods during which gas may be present in the flowback but with insufficient volume and consistency of flow to enable either combustion or recovery of the gas through separation. Our clarification letter further responded to the issue of routing of all recovered liquids to storage vessels. We explained that the term ''recovered liquids'' refers to condensate, crude oil and produced water recovered through the separation process. Although the 2012 NSPS does not define ''recovered liquids,'' the discussion of the proposed NSPS for storage vessels describes the storage of ''crude oil, condensate and produced water.'' (see 76 FR 72763, August 23, 2011). In our clarification letter to API, we stated that the 2012 final rule accurately reflected our intent to require these liquids to be routed to ''storage vessels,'' which may be subject to control in the rule depending on their potential to emit VOC and their affected facility status. We confirmed that the initial flowback (prior to recovery of these liquids through separation) may be routed to temporary fracture tanks (frac tanks) or other portable tanks (i.e., tanks that do not meet the definition of ''storage vessel'') as long as separation occurs as soon as practicable, consistent with the general duty to maximize resource recovery and minimize releases to the atmosphere as required in § 60.5375(a)(4).

In light of petitioners' assertions and the confusion caused by the current regulatory language in the well completion provisions, we reexamined the regulatory text in § 60.5375 and concluded that more clarity is needed such that owners, operators, regulatory agencies and the public could readily understand what was required at various stages of a hydraulically fractured well completion operation.

We believe that the requirements of the rule would be easier to understand if the rule identified distinct stages associated with well completion, with each stage having specific requirements for handling of gases and liquids. To that end, we are proposing that each well completion subject to § 60.5375 consists of three distinct stages.

The first stage begins with the first flowback from the well following hydraulic fracturing or refracturing, and is characterized by high volumetric flow water, with sand, fracturing fluids and debris from the formation with very little gas being brought to the surface, usually in multiphase slug flow. As the flowback proceeds, the amount of gas appearing in the flowback increases to the point where there is enough gas present for a separator to function, at which time the well completion would enter the second stage. We are proposing that the first stage be defined as the ''initial flowback stage,'' during which the flowback must be routed to a ''well completion vessel'' that can be an open top frac tank, a lined pit or any other vessel. During the initial flowback stage, there would be no requirement for controlling emissions from the tank, and any gas in the flowback during this stage could be vented.[3] We propose that the flow must be diverted to a separator as soon as a sufficient amount of gas is present in the flowback to operate the separator. The EPA is seeking to establish, if possible, objective criteria for determining when there is sufficient gas in the flowback for the separator to function and is therefore soliciting comment on one potential approach. It is our understanding that some operators monitor the gas concentration at the vessel receiving the flowback for safety reasons and to determine that sufficient gas is present in the flowback. When the gas concentration approaches the lower explosive limit (LEL) (i.e., approaches flammability), these operators direct the flowback to a separator. While we are aware that some operators employ this technique, we are uncertain whether it can be used effectively in all applications and whether there are other techniques used by operators to make this determination. We therefore solicit comment on the suitability of the ''LEL method'' when used for this purpose and seek information on other techniques or indicators that may be used to determine when sufficient gas is present for a separator to function.

The second stage would begin when the flowback gases and liquids are routed to the separator, which would be required as soon as sufficient gas is present for the separator to function. This stage, which we propose to define as the ''separation flowback stage,'' is characterized by the separator operating (i.e., there is sufficient gas in the flowback to maintain a gaseous phase and one or more liquid phases in the separator). During the separation flowback stage, the operator would be required to route the recovered gas into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an on-site fuel source or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. If, during the separation flowback stage, it was technically infeasible to route the recovered gas to a flow line or collection system (e.g., if there was no flow line or other infrastructure available at the site for collection of the gas), reinject the gas or use the gas as fuel or for other useful purpose, the recovered gas (i.e., ''flowback emissions'') would have to be combusted using a completion combustion device. No direct venting of recovered gas would be allowed during the separation flowback stage. If, at any time during the separation flowback stage, the recoverable gas present in the flowback becomes insufficient to maintain operation of the separator, the operation would revert to the initial flowback stage until the gas was again present in sufficient volume to operate the separator. During the separation flowback stage, all liquids from a separator could be directed to one or more well completion vessels or storage vessels, or be re-injected into the well or another well (i.e., during this stage, operators would not be required to route flowback liquids to ''storage vessels'' as defined in the NSPS). During this stage of a completion, the flowback continues to have a very high volumetric flow rate, with the hydrocarbon content (and potential to emit VOC) often increasing

[1] Letter from Matt Todd, American Petroleum Institute, to Bruce Moore, EPA Office of Air Quality Planning and Standards, July 25, 2012.

[2] Letter from Peter Tsirigotis, EPA Office of Air Quality Planning and Standards, to Matt Todd, American Petroleum Institute, September 28, 2012.

[3] Recent studies have shown that air emissions from open top tanks used during initial flowback are very low. Allen, David, T., et al. 2013. *Measurements of methane emissions at natural gas production sites in the United States.* Proceedings of the National Academy of Sciences (PNAS) 500 Fifth Street NW., NAS 340 Washington, DC 20001 USA. October 29, 2013.

with time and being dependent on the characteristics of the gas (e.g., to what degree the gas is ''wet'' or ''dry''). It is our understanding that the initially high volume and inconsistent character of the flowback will gradually subside and stabilize. At some point, the flowback will have declined and stabilized enough to allow continuous recovery of the gas. It would also allow separation and recovery of any crude oil, condensate and produced water. We propose to define this point as the end of the separation flowback stage and the beginning of the ''production stage.'' We seek to establish, if possible, objective criteria on which to base a determination that the well has reached that point, and we therefore solicit comment on the characteristics of the flow or other conditions that could be used to establish such criteria. During the production stage, we propose to prohibit gas from the separator being vented or controlled by combustion, and require that all recovered liquids be routed to storage vessels.

We are proposing that the beginning of the production stage would also begin the 30-day period for determining VOC potential to emit for purposes of making a storage vessel affected facility determination in accordance with the procedure in § 60.5365(e). If the criteria under § 60.5365(e) were met, the operator would have to comply with the control requirements in § 60.5395(d)(1) within 60 days after the beginning of the production stage. We are proposing to amend § 60.5365(e) to reflect that, for purposes of the well completion provisions, the 30-day period for the affected facility determination required § 60.5365(e) would commence at the beginning of the production stage. We are proposing to amend § 60.5395(d)(1)(i) to reflect that, for purposes of the well completion provisions, control would be required no later than 60 days from the beginning of the production stage. We propose revising § 60.5395(d)(1)(i) to read:

(i) Except as otherwise provided in this paragraph, for each Group 2 storage vessel affected facility, you must achieve the required emissions reductions by April 15, 2014, or within 60 days after startup, whichever is later. For storage vessels receiving liquids pursuant to the standards for gas well affected facilities in § 60.5375, you must achieve the required emissions reductions within 60 days after the beginning of the production stage as defined in § 60.5430.

In addition, we are proposing amendments to the reporting and recordkeeping requirements in § 60.5420 to revise the terminology used in that section relating to periods of recovery, combustion and venting to be compatible with the terms identified in the proposed clarifying amendments to § 60.5375.

Similarly, we are proposing revisions to the terms used in the regulatory text for exploratory, delineation and low pressure wells at § 60.5375(f) to be consistent with the proposed amended terminology and requirements in § 60.5375(a).

Petitioners also raised the issue of ''screenouts'' and ''coil tubing cleanouts,'' which are remedial operations sometimes required during flowback when flow is impeded or blocked by packed proppant (sand) and must be restored to prevent permanent damage to the well. As related in petitions, a screenout is the first attempt to clear the proppant that can plug the wellbore. A screenout involves flowing the well to a frac tank in a manner to achieve maximum velocity to carry the sand out of the well. If a screenout is unsuccessful in clearing the packed sand from the wellbore, then the well typically is ''jetted'' using a string of coil tubing and nitrogen gas to dislodge the sand and provide sufficient lift energy to flow it to surface. Small amounts of gas and condensate may be part of the flowback fluids during screenouts and coil tubing cleanouts. In our clarification letter to API, we explained that any gas or vapor liberated during screenouts and coil tubing cleanouts, both of which are operations prior to the point of separation, were not ''flowback emissions'' [4] and, as a result, were not subject to the work practice standards for gas well affected facilities.

2. Definition of ''Low Pressure Gas Well''

In the August 23, 2011, proposed rule, the EPA solicited comments on situations where reduced emission completion (REC) would be infeasible (see 76 FR 52758, August 23, 2011). Several commenters highlighted technical issues that prevent the implementation of a REC on what they referred to as ''low pressure'' gas wells because of the lack of the necessary reservoir pressure to flow at rates appropriate for the transportation of solids and liquids from a hydraulically fractured gas well completion against an imposed back-pressure. Based on our analysis of the public comments received, we learned that there are certain wells where a REC is infeasible because of the characteristics of the reservoir and the well depth that will not allow the flowback to overcome the gathering system pressure due to the back pressure imposed by the REC surface equipment. Accordingly, in response to those comments, we provided in the 2012 final NSPS at § 60.5375(f) that ''low pressure'' gas wells (i.e., those wells for which a REC would not be feasible because of a combination of well depth, reservoir pressure and flow line pressure) would not be required to meet the requirements for recovery of gases and liquids required under § 60.5375(a), except as provided in § 60.5375(f)(2) which subjects wildcat, delineation and low pressure gas wells to requirements for combustion of flowback emissions and to the general duty to safely maximize resource recovery and minimize releases to the atmosphere required under § 60.5375(a)(4). Under the 2012 final NSPS, low pressure wells are treated the same as exploratory and delineation wells (i.e., they are not required to perform a REC). We also added a definition of ''low pressure gas well'' in the final rule that is based on a mathematical formula that takes into account a well's depth, reservoir pressure and flow line pressure. The definition at § 60.5430 is as follows:

Low pressure gas well means a well with reservoir pressure and vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter.

A detailed discussion of development of the definition and derivation of the formula was provided in the Supplemental Technical Support Document for the 2012 final rule.[5]

Following publication of the final rule, a group of petitioners representing independent oil and natural gas owners and operators submitted a joint petition for administrative reconsideration of the 2012 NSPS. The petitioners questioned the technical merits of the low pressure well definition and asserted that the public had not had an opportunity to comment on the definition because it was added in the final rule. The petitioners expressed concern that the formula adopted in the 2012 NSPS was based on ''questionable assumptions'' and ''sparse data'' and will ''exclude from its scope many gas wells drilled in formations that historically have been

[4] In the 2012 NSPS, § 60.5375(a)(2) and (3) require that ''flowback emissions'' be either routed to a flow line or to a completion combustion device. In our clarification letter to API, we clarified that ''flowback emissions'' refers to the recovered gas and vapor after separation.

[5] Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution—Background Supplemental Technical Support Document for the Final New Source Performance Standards, USEPA, Office of Air Quality Planning and Standards, April 2012.

recognized as 'low pressure.' Accordingly, in the view of the petitioners, this exclusion—or lack thereof—has the potential to directly affect many smaller producers, who are less likely to be able to bear the costs of implementing costly RECs.'' [6] However, the administrative petition did not include any details on which of EPA's assumptions is questionable and why, or what additional data the petitioners consider necessary to support EPA's ''low pressure gas well'' definition. We were therefore unable to assess petitioners' assertions regarding the ''low pressure gas well'' definition in the 2012 final NSPS.

On March 24, 2014, the petitioners submitted to the EPA a suggested alternative definition [7] for consideration. The petitioners' definition is based on the fresh water hydrostatic gradient of 0.433 pounds per square inch per foot (psi/ft). The petitioners assert that this approach is straightforward and has been recognized for many years in the oil and natural gas industry and by governmental agencies and professional organizations. As expressed in the paper submitted by the petitioners, the alternative definition for consideration by the EPA, as stated by the petitioners, would be:

A well where the field pressure is less than 0.433 times the vertical depth of the deepest target reservoir and the flow-back period will be less than three days in duration

We agree with the petitioners that this alternative definition is straightforward and easy to use. However, we are concerned that it may be too simplistic and may not adequately account for the parameters that must be taken into account when determining whether a REC would be feasible for a given hydraulically fractured gas well. Further, we question how an operator would know before flowback begins that the flowback period would be less than 3 days in duration.

We believe that, to determine whether the flowback gas has sufficient pressure to flow into a flow line, it is necessary to account for reservoir pressure, well depth and flow line pressure. In addition, it is important for any such determination to take into account pressure losses in the surface equipment used to perform the REC. The EPA's proposed definition was developed to account for these factors.

We further disagree with the petitioners' assertion that the EPA definition is too complicated. We believe that values for each of the three parameters discussed above and used in the EPA definition are known by operators in advance of flowback and that the relatively simple calculation called for in the EPA definition could be performed with a basic hand-held calculator and should not pose difficulty or hardship for smaller operators.

However, we agree with the petitioners that the public should be provided an opportunity to comment on the 2012 definition of ''low pressure gas well.'' We are therefore re-proposing that definition for notice and comment. In addition, we solicit comment on the definition suggested by the petitioners. The petitioners' background paper and supporting documents for the alternative definition have been placed in the public docket for this action. We believe that soliciting comments on both definitions would help us better understand and characterize the term ''low pressure gas well'' for which REC is not feasible.

B. Storage Vessels

On September 23, 2013, the EPA published amendments primarily focused on storage vessel implementation issues raised by petitioners following publication of the 2012 final NSPS. Following publication of the 2013 storage vessel amendments, three petitioners raised issues with regard to various provisions of the amendments. Among these issues are requirements for determining PTE for storage vessels employing vapor recovery under a legal and practically enforceable limitation, requirement for thief hatches being properly seated and clarification of the term ''storage vessels removed from service.''

1. PTE Determination for Storage Vessels Employing Vapor Recovery Under a Legally and Practically Enforceable Limitation

In the 2013 final storage vessel amendments to the NSPS, we provided at § 60.5365(e) that the determination of a storage vessel's VOC PTE may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a federal, state, local or tribal authority. We further provided that any vapor from the storage vessel that is recovered and routed to a process through a vapor recovery unit (VRU) designed and operated as specified in § 60.5365(e) is not required to be included in the determination of VOC PTE.

In petitions for reconsideration of the storage vessel amendments, petitioners pointed out that, if a VRU is required by a legally and practically enforceable limitation under which the storage vessel is operating, then § 60.5365(e)(1) through (4) should not apply. The petitioners explained that, in such cases, removal of the VRU would violate the enforceable limitation, thereby making the prior affected facility determination of VOC PTE invalid. They further assert their understanding that the EPA intended that § 60.5365(e)(1) through (4) should apply only to storage vessels which are not under a legal and practically enforceable limit but which are employing vapor recovery to lower the VOC PTE.

§ 60.5365(e) allows an owner or operator of a storage vessel to exclude from its PTE determination any vapor routed to a process through a VRU provided that conditions in § 60.5365(e)(1) through (4), which relate to the design and operation of cover and closed vent system associated with the VRU, are met (hereinafter referred to as the ''PTE exclusion provision''). However, this is not the only way for a storage vessel to demonstrate that its PTE is below the 6 tpy threshold. As stated in the 2013 amendment and reiterated above, a storage vessel's PTE determination can take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a federal, state, local or tribal authority. However, it appears that there may be misinterpretation of the PTE exclusion provision as requiring compliance with § 60.5365(e)(1) through (4) in all cases, even where a storage vessel has VOC PTE less than 6 tpy under a legally and practically enforceable limit in an operating permit or other requirement established under a Federal, state, local or tribal authority. Under such a permit or limitation, an operator therefore does not need to invoke the NSPS PTE exclusion provision. Further, we conclude that the PTE exclusion provision would only be invoked by a storage vessel absent any legally and practically enforceable limit under which the storage vessel was being operated to maintain its VOC PTE less than 6 tpy.

In light of the points raised by the petitioners and considering the EPA's original intent, we are proposing to amend § 60.5365(e) to allow the PTE exclusion provision only in cases where

[6] Letter from James D. Elliott, Spilman, Thomas & Battle PLLC, to Lisa P. Jackson, EPA Administrator, October 15, 2012; Petition for Administrative Reconsideration of Final Rule ''Oil and Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews,'' 77 FR 49490 (August 16, 2012).

[7] Email from James D. Elliott, Spilman, Thomas & Battle PLLC, to Bruce Moore, EPA, March 24, 2014.

a storage vessel is not subject to any legal and practically enforceable limitation or other requirement under a Federal, state, local or tribal authority. Accordingly, we propose to revise the last full paragraph of § 60.5365(e) as follows:

For storage vessels not subject to a legally and practically enforceable limit in an operating permit or other requirement established under a federal, state, local or tribal authority, any vapor from the storage vessel that is recovered and routed to a process through a VRU designed and operated as specified in this section is not required to be included in the determination of VOC potential to emit for purposes of determining affected facility status, provided you comply with the requirements in paragraphs (e)(1) through (4) of this section.

2. Thief Hatch Properly Seated

Thief hatches are generally hinged access openings in the roof of storage vessels that serve as emergency overpressure relief devices and a point of access for obtaining a sample of the material stored or for gauging the liquid level. To be functional, the thief hatch must be able to open when access is needed, yet close and seal properly to prevent vapor at very low pressure from escaping. The hatch must be able to open readily during overpressure events to prevent damage to the storage vessel. Storage vessels used in this industry sector are generally designed to operate at atmospheric pressure. The 2012 final NSPS requires at § 60.5411(b)(3) that thief hatches be ''weighted and properly seated.''

Petitioners asserted that the requirement for the thief hatch lid to be ''weighted'' is too restrictive, since there are other types and mechanisms that provide the same functionality (i.e., the lid presses on the seating surface with sufficient force to ensure proper seating while allowing opening manually for personnel access or automatically during overpressure events) as a weighted lid thief hatch. The petitioners requested that the NSPS be revised to allow the use of other types (e.g., hatches with spring-loaded lids) besides weighted-lid hatches.

We agree with the petitioners that other mechanisms that would provide equivalent function to that provided by a weight should be allowed for thief hatch lid control, since the important factor here is to ensure that the hatch lid remains properly closed, whether with a weight or another mechanism, at all times except during personnel access and overpressure events. As a result, we are proposing to amend § 60.5411(b)(3) to require that the thief hatch be equipped with a mechanism or be of such design and properly maintained and operated to ensure that the lid remains properly seated.

3. Storage Vessels Removed From Service

The 2013 final storage vessel amendments to the NSPS added provisions at § 60.5395(f) that apply to storage vessel affected facilities that are removed from service. Provisions are also included for storage vessel affected facilities that are later returned to service.

Petitioners assert that the provisions for storage vessel affected facilities that are removed from service need clarification to avoid misinterpretation that the NSPS requires reporting of every instance of a storage vessel being temporarily shut down for maintenance. In addition, petitioners requested that the EPA provide clarity by adding a definition of ''removed from service.'' Petitioners also requested that § 60.5395(f) state explicitly that a storage vessel affected facility that is removed from service is no longer subject to the control, reporting or recordkeeping requirements of the NSPS, other than reporting that it has been removed from service, until such time as it is subsequently returned to service. Petitioners also suggested that the required notifications include the date that the storage vessel-affected facility is removed from service or restored to service to assist in documenting the period of time for which the NSPS did not apply to a given storage vessel-affected facility.

We reexamined § 60.5395(f) and propose to clarify the requirements regarding storage vessel affected facilities removed from service to avoid potential misinterpretation of these requirements. Our intent in including such provisions in the 2013 storage vessel amendments was to ensure that unnecessary burden was not imposed by the NSPS by requiring emission control, compliance monitoring, reporting and recordkeeping activities for storage vessels that were removed from service for reasons other than maintenance. Based on our review, we are proposing to add a definition of ''removed from service'' to § 60.5430 as follows:

Removed from service means that a storage vessel affected facility has been physically isolated and disconnected from the process for a purpose other than maintenance and is no longer used to contain crude oil, condensate, produced water or intermediate hydrocarbon liquids. If the storage vessel affected facility is reconnected to the process, or introduced with crude oil, condensate, produced water or intermediate hydrocarbon liquids at the same location, or relocated to another location and utilized as a storage vessel for crude oil, condensate, produced water or intermediate hydrocarbon liquids, it will be deemed to no longer be ''removed from service'' and at that time will be deemed ''returned to service'' and subject to the provisions of this subpart applicable to such vessel.

We are also proposing to amend § 60.5395(f)(1) and (2), and § 60.5420(b)(6) to require that the dates that storage vessel-affected facilities are removed from service and returned to service be included when reporting those actions.

4. Electronic Spark Ignition for Combustion Devices for Well Completions, Storage Vessels and Wet Seal Centrifugal Compressors

The 2012 final NSPS requires a continuous pilot flame for well completion combustion devices and for combustors used to control emissions from storage vessels and wet seal centrifugal compressors. Commenters on the 2011 proposed NSPS and NESHAP had asserted that these rules should allow the use of automatic electronic spark ignition as an alternative to a continuous pilot flame for these control devices. In our response to public comments, we had clarified that the rule does not allow electronic ignition devices as surrogates for a continuous ignition source. The continuous ignition source is designed to combust the flammable portion of the flowback gas from a well completion, even if the flowback gas has a low BTU content. We further explained that an electronic ignition device designed for ignition of a combustible stream would not be successful at combusting VOC portions of low BTU flowback gas. With regard to storage vessels, we acknowledged the growing use of electronic spark ignition systems for flares. We explained that, however, given the intermittent and inconsistent nature of emissions from tanks in this industry combined with the highly variable VOC concentration in the emissions, we did not believe a spark-ignited flare would achieve the same level of emission reduction as a flare with a continuous flame present. We also noted that there were not sufficient data at this time to suggest that electronic ignition systems on combustion devices are capable of continuously supplying a constant source of ignition to keep a flame present on a continuous basis. In addition, for flares, test data for which the current standards in §§ 63.11(b) and 60.18 were written show that operating a flare with a continuously lit pilot adds an additional degree of flame stability to the flare itself. Therefore, we did not allow electronic spark ignition as an alternative to a continuous pilot flame in the final rule.

The issue was raised by petitioners in response to the 2012 final NSPS in the context of completion combustion devices, but petitioners did not provide additional data or information to refute EPA's rationales for not allowing electronic spark ignition in the 2012 Final NSPS, as described above. The issue was raised again in public comments received on the 2013 proposed storage vessel amendments without additional data or information. However, the commenters asserted that the EPA's own Natural Gas Star program encourages the use of electronic ignition instead of a continuous pilot flame.[8] In our response to public comments, we maintained our previous position and rationales and declined to provide in the final NSPS storage vessel amendments that electronic spark ignition would be an acceptable alternative to continuous pilot flame for storage vessel control devices.

The EPA encourages innovation and also believes that resource conservation should be encouraged where possible. We believe electronic spark ignition is a promising technology, and for that reason highlighted it in the Natural Gas STAR publication cited by the petitioners. However, we still have concerns about the dependability of these devices and control efficiency afforded by this technology and would like to have more information that could inform further consideration of the petitioners' assertions.

We solicit information that would inform our evaluation of this technology as an alternative to a continuous pilot flame used with combustion devices for control of emissions from well completions, storage vessels and centrifugal compressor wet seal degassing systems. Specifically we solicit information, including any test data or other documentation, that may help address the following topics relative to the operation of an electronic spark ignition: (1) Appropriate design, operation and maintenance procedures to ensure proper combustion of the waste stream; (2) use of safety valves to ensure that no gas is available for combustion if the ignition system is not functional; (3) measures that could be taken to avoid vapor venting upstream of the control device in cases where the safety valve remains closed; (4) frequency of monitoring for proper operation; (5) specific checks to be made to ensure proper operation; (6) operating parameters that affect pilot-less flare performance and flare flame stability; (7) effects of gas with low BTU content or gas of variable VOC content; and (8) how often these systems need to be replaced.

In addition, we are interested in learning more about the use of this technology as a means of ensuring that continuous flame pilots remain functional at all times. Therefore, we also solicit comment, including any supporting data or information, on whether automatic spark ignition relighting systems should be required as a means of ensuring that continuous flame pilots remain functional at all times.

Based on our evaluation of the data and comments received, we may provide language in the final rule that would allow electronic spark ignition as an alternative to a continuous pilot flame. We may also provide language in the final rule that would require automatic electronic spark ignition relighting systems.

C. Routing of Reciprocating Compressor Rod Packing Emissions to a Process

The 2012 final NSPS includes operational (i.e., ''work practice'') standards for reciprocating compressors to reduce emissions from gas vented from the piston rod packing as the rod moves during operation. The rule requires regular rod packing replacement every 26,000 hours of operation or, if the owner and operator elect, every 36 months.

On October 15, 2012, the Administrator received a petition for administrative reconsideration of the performance standards for reciprocating compressors. The petitioners asserted that an available alternative would reduce reciprocating compressor emissions to levels equivalent to, or better than, the emission levels achieved by the operational standard.[9] The alternative technology consists of recovering vented emissions from the rod packing under negative pressure and routing these emissions of otherwise vented gas to the air intake of a reciprocating internal combustion engine that would burn the gas as fuel to augment the normal fuel supply. The system's computerized air/fuel control system would then adjust the normal fuel supply to accommodate the increased fuel made available from the recovered emissions and thereby take advantage of the recovered emissions while avoiding an overly rich fuel mixture.

The petitioner requested that the EPA consider this alternative technology and that the EPA revise the provisions of Subpart OOOO to allow for this alternative to the operational standard. The petitioner pointed out that subpart OOOO already includes similar options for handling of vented emissions from centrifugal compressors and storage vessels and that similar alternatives could apply for reciprocating compressors as well. Access to similar technologically valid approaches should be an option for reciprocating compressors. The petitioner reasoned that such an option would provide emission reductions in excess of 99.5 percent attributed to the efficiency of the computer-controlled combustion of the engine and the recovery of the emissions under negative pressure produced by the engine air intake. The petitioner reasoned that emission reductions would be commensurate with or better than the reductions from the operational standard.

Finally, the petitioner asserted that alternatives to the reciprocating compressor operational standard were not adequately reviewed by the EPA and, in its response to comments document, the EPA addressed comments from the petitioner and others with little more than a passive response.[10]

The EPA values innovation on the part of owners, operators and equipment vendors serving the Oil and Natural Gas Sector. We also believe that resource conservation should be encouraged where possible and that alternatives should be flexible enough, within the law, to provide opportunities for innovation and resource recovery. Under the 2012 final NSPS for reciprocating compressors, an owner or operator must either (1) replace the rod packing every 26,000 hours of operation; or (2) replace the rod packing every 36 months. Any other options considered would need to provide at least the level of emission control that the existing options provide. Based on our review of the information submitted by the petitioner, we conclude that the technology has merit and would provide equivalent or better emissions reduction

[8] U.S. Environmental Protection Agency, Natural Gas STAR Program. *Partner Reported Opportunities—Install Electronic Flare Ignition Devices,* PRO Fact Sheet No. 903, 2011.

[9] Letter from Veronica Nasser, REM Technologies, Inc., to Lisa P. Jackson, EPA Administrator, Petition for Reconsideration.

[10] Docket document number EPA–HQ–OAR–2010–0505–4546, ''Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 40 CFR Parts 60 and 63, Response to Public Comments on Proposed Rule August 23, 2011 (76 FR 52738),'' Section 2.7.3, (U.S. EPA, April 2012).

since the emissions would be captured under negative pressure, allowing all emissions to be routed to the engine. It is our understanding that this technology may not be applicable to every compressor installation and situation. However, we are proposing this as an alternative to the current work practice standards and, therefore, it would be within the operator's discretion to choose whichever option is most appropriate for the application and situation at hand. Based on these considerations and on the information submitted by the public and the petitioner, we are proposing to include in the NSPS a third option for controlling emissions from reciprocating compressor rod packing as described above.

In light of the above considerations, we are proposing to revise § 60.5385(a) to reflect that a third option for controlling VOC emissions from the reciprocating compressor rod packing would be to capture the emissions and route them to a process. ''Route to a process'' was defined in the 2012 NSPS at § 60.5430 to work in conjunction with the standards for storage vessels and wet seal centrifugal compressors. By using the same term in the proposed third option, emissions captured from the rod packing would be treated the same as emissions recovered from a storage vessel or from a wet seal centrifugal compressor. Specifically, for example, in the petitioner's case, the compressor engine would be the ''process'' to which the emissions would be routed. Although we have used the petitioner's application as an example, we want to be clear that the third option would not be limited to use of the captured emissions as on site fuel. Similar to vapor recovery applied to storage vessels and wet seal centrifugal compressors, routing the emissions to a process would also include routing of the emissions to a flow line or other beneficial use.

As a result, we propose to amend § 60.5385(a) to read as follows:

(a) You must follow the requirements of paragraph (a)(1), (2) or (3) of this section.

(1) Replace the reciprocating compressor rod packing before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of your reciprocating compressor-affected facility, or October 15, 2012, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) Replace the reciprocating compressor rod packing prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the date of startup for a new reciprocating compressor for which the rod packing has not yet been replaced.

(3) Route the rod packing emissions through a closed vent system that meets the requirements of § 60.5411(c) to a process.

We are also proposing to amend the closed vent system requirements in § 60.5411(a) and (b) to apply to reciprocating compressors in addition to centrifugal compressor wet seal degassing systems, to which those sections already apply.[11] Similar amendments are being proposed to the continuous compliance requirements in § 60.5415 and inspection and monitoring requirements in § 60.5416 to apply to reciprocating compressors.

D. Equipment Leaks at Gas Processing Plants

1. Small Gas Processing Plants and Gas Processing Plants Located on the Alaskan North Slope

The equipment leaks standards in the 1985 NSPS subpart KKK requires routine leak detection at natural gas processing plants for certain equipment, specifically pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief valves from gas/vapor service. Subpart KKK provides for exemptions for pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief valves in gas/vapor service from routine monitoring requirements at small natural gas processing plants (i.e., plants that do not have the design capacity to process at least 10 million standard cubic feet (scf) of field gas per day) and at natural gas processing plants located on the Alaskan North Slope. In the 2012 NSPS, we updated the subpart KKK standards by lowering the leak definition for valves from 10,000 parts per million (ppm) to 500 ppm and adding connectors to the list of equipment to be monitored. The revised standards, which are codified in subpart OOOO, apply to affected facilities at onshore natural gas processing plants that commence construction, modification or reconstruction after August 23, 2011. Except for the revisions described above, we retained the other provisions of subpart KKK by adopting the subpart KKK regulatory text, including the above mentioned exemptions, in the new subpart OOOO. However, in adopting the subpart KKK regulatory text on the exemptions, we inadvertently failed to update the equipment list to include connectors. As a result, connectors were not listed in § 60.5401(d) and (e) as exempt from the routine leak detection requirements at small gas processing plants and gas processing plants located on the Alaskan North Slope.

Petitioners pointed out that connectors had been added to the list of equipment for routine leak detection in subpart OOOO but had not been similarly added to the list of equipment exempted from routine leak detection at small gas processing plants and at gas processing plants located on the Alaskan North Slope. The petitioners requested that we amend the NSPS to correct this apparent oversight. We agree that this omission was an oversight and that it was not our intent for the 2012 NSPS to single out connectors at small gas processing plants and at gas processing plants located on the Alaska North Slope for routine leak detection while exempting the other equipment at these plants from such requirement. As a result, we are proposing to amend § 60.5401(d) and (e) to add connectors to the list of equipment exempt from routine leak detection at these plants.

2. Equipment Under Subpart OOOO Subject to Leak Detection Requirements

Petitioners pointed out that the definition of ''equipment'' in § 60.5430 of the 2012 final NSPS could be misinterpreted to expand the scope of the equipment leaks program under subpart OOOO to cover beyond onshore-gas processing plants, which was the scope of subpart KKK. The term ''equipment'' is currently defined in § 60.5430 as follows:

Equipment means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by this subpart.

As discussed above, the 2012 final NSPS subpart OOOO updated the 1985 NSPS subpart KKK by lowering the leak definition for valves from 10,000 ppm to 500 ppm and requiring monitoring of connectors. Otherwise, subpart OOOO retains the other provisions of the subpart KKK by adopting those provisions, including the definition of ''equipment.'' As mentioned above, the definition of ''equipment'' includes ''any device or system required *by this subpart*.'' [Emphasis added]. Because subpart KKK pertained only to onshore natural gas processing plants, the phrase ''any device or system required by this subpart'' refers to only devices and systems at onshore natural gas processing plants. However, since subpart OOOO also covers affected facilities not located at onshore natural gas processing plants, the phrase could be misinterpreted to apply to every

[11] § 60.5411(a) and (b) are the closed vent system and cover requirements that are meant to ensure that all emissions from the compressor rod packing will reach a process.

affected facility under the entire subpart OOOO, including those not located at onshore natural gas processing plants. To avoid any such misinterpretation, we are proposing to amend the definition of ''equipment'' in § 60.5430 to clarify as follows:

Equipment, as used in the standards and requirements in this subpart relative to the equipment leaks of VOC from onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by those same standards and requirements in this subpart.

E. Definition of ''Responsible Official''

The 2012 final rule requires certification by a responsible official of the truth, accuracy and completeness of the annual report. Petitioners pointed out that the definition of ''responsible official'' is not appropriate for the oil and natural gas sector due to the large number and wide geographic distribution of the small sources involved. Petitioners suggested that the EPA should develop a certification requirement specific to the Oil and Natural Gas Sector NSPS that would allow delegation of the authority of a responsible official to someone, such as a field or production supervisor, who has direct knowledge of the day to day operation of the facilities being certified, without requiring that such delegation be pre-approved by the permitting authority.[12]

We reexamined the definition of ''responsible official'' and agree with petitioners that the current language in the NSPS, specifically the requirement to seek advance approval by the permitting authority of the delegation of authority to a representative if the facility employs 250 or fewer persons, is too burdensome for the oil and natural gas sector. The oil and natural gas sector, especially the production (i.e., ''upstream'') segment, is characterized by many individually small facilities (e.g., well sites) with oversight typically by a production field office serving a large geographic area such as a basin. We believe a production supervisor or field supervisor who is in charge of a field office would be analogous to a ''plant manager'' in other sectors, because he or she is ''responsible for the overall operation of one or more manufacturing, production, or operating facilities'' (from § 60.5430, definition of ''responsible official''). We believe positions such as these are much closer to the day to day operations in this sector and would be appropriate to certify as to the truth, accuracy and completeness of annual reports and compliance certifications. However, because most oil and gas production facilities are small and therefore unlikely to have more than 250 persons, delegating the authority of responsible official to an oil and gas production supervisor or field supervisor would almost always require the permitting authority's approval.

We believe that the oil and natural gas sector is unique in that the ones with most knowledge of the facilities being certified are field or production supervisors overseeing such facilities, which are numerous across country but generally with few employees in each facility. As a result, requiring prior approval of a delegation of the authority of a responsible official because most of these facilities employ 250 persons or less is unnecessarily burdensome and may potentially affect the facilities' ability to comply with the certification requirement in the event there are delays in approvals of delegation. We therefore propose requiring advance notification instead of advance approval before such delegation becomes effective.

Petitioners also noted that the current definition does not adequately address the complex ownership arrangements of limited partnerships. We agree with the petitioners and believe limited partnerships should be reflected in the definition along with sole proprietorships and partnerships which are currently addressed.

In light of the considerations discussed above, we are proposing to amend the definition of ''responsible official'' to make such delegation effective after advance notification rather than after approval. Requirements for delegation to representatives responsible for one or more facilities that employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars) are unchanged from the 2012 NSPS (i.e., there is no advance notification or approval required for such delegations).

In addition, the 2012 NSPS uses the term ''permitting authority'' in the definition of ''responsible official.'' The NSPS is not a permitting program, and the annual compliance certification that requires signature of the ''responsible official'' is a requirement of the NSPS and is not associated with a permitting program. As a result, we are proposing to replace the term ''permitting authority'' with ''Administrator'' in the definition of ''responsible official'' to be consistent with other notification and reporting requirements of the NSPS.

F. Affirmative Defense

In the 2012 NSPS subpart OOOO, the EPA had included an affirmative defense to civil penalties for violations caused by malfunctions. For the reasons provided below, we are proposing to remove the affirmative defense provisions in the 2012 NSPS subpart OOOO.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as ''any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.'' (40 CFR 60.2). The EPA has determined that CAA section 111 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 111 standards. Nothing in CAA section 111 or in case law requires that the EPA anticipate and account for the innumerable types of potential malfunction events in setting emission standards. CAA section 111 provides that the EPA set standards of performance which reflect the degree of emission limitation achievable through ''the application of the best system of emission reduction'' that the EPA determines is adequately demonstrated. A malfunction is a failure of the source to perform in a ''normal or usual manner'' and no statutory language compels the EPA to consider such events in setting standards based on the ''best system of emission reduction.'' The ''application of the best system of emission reduction'' is more appropriately understood to include operating units in such a way as to avoid malfunctions.

Further, accounting for malfunctions in setting emission standards would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category and given the difficulties associated with predicting or accounting for the frequency, degree, and duration of various malfunctions that might occur. The performance of units that are

[12] During consideration of this issue, we realized that the definition of ''responsible official'' in the 2012 NSPS refers to ''permitting authority'' in error. This occurred when we took language from the Title V definition which uses ''permitting authority'' appropriately. However, in the case of the NSPS, we are proposing to change the definition in § 60.5430 to replace ''permitting authority'' with ''Administrator'' which is appropriate for the NSPS. For purposes of the discussion in this preamble, we continue to refer to ''permitting authority,'' since the current definition still uses that term until such an amendment would be effective.

malfunctioning is not ''reasonably'' foreseeable. See, e.g., *Sierra Club* v. *EPA,* 167 F.3d 658, 662 (D.C. Cir. 1999) (''The EPA typically has wide latitude in determining the extent of data-gathering necessary to solve a problem. We generally defer to an agency's decision to proceed on the basis of imperfect scientific information, rather than to 'invest the resources to conduct the perfect study.' '') *See also, Weyerhaeuser* v. *Costle,* 590 F.2d 1011, 1058 (D.C. Cir. 1978) (''In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by 'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation.''). In addition, emissions during a malfunction event can be significantly higher than emissions at any other time of source operation and thus accounting for malfunctions could lead to standards that are significantly less stringent than levels that are achieved by a well-performing non-malfunctioning source. It is reasonable to interpret CAA section 111 to avoid such a result. The EPA's approach to malfunctions is consistent with CAA section 111 and is a reasonable interpretation of the statute.

In the event that a source fails to comply with the applicable CAA section 111 standards as a result of a malfunction event, the EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. The EPA would also consider whether the source's failure to comply with the CAA section 111 standard was, in fact, ''sudden, infrequent, not reasonably preventable'' and was not instead ''caused in part by poor maintenance or careless operation.'' 40 CFR 60.2 (definition of malfunction).

Further, to the extent the EPA files an enforcement action against a source for violation of an emission standard, the source can raise any and all defenses in that enforcement action and the federal district court will determine what, if any, relief is appropriate. The same is true for citizen enforcement actions. Similarly, the presiding officer in an administrative proceeding can consider any defense raised and determine whether administrative penalties are appropriate.

In the 2012 NSPS, 40 CFR 60, subpart OOOO, the EPA included an affirmative defense as an effort to create a system that incorporates some flexibility, recognizing that there is a tension, inherent in many types of air regulation, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission standards may be violated under circumstances entirely beyond the control of the source. Although the EPA recognized that its case-by-case enforcement discretion provides sufficient flexibility in these circumstances, it included the affirmative defense in the 2012 NSPS subpart OOOO to provide a more formalized approach and more regulatory clarity. *See Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1057–58 (D.C. Cir. 1978) (holding that an informal case-by-case enforcement discretion approach is adequate); *but see Marathon Oil Co.* v. *EPA,* 564 F.2d 1253, 1272–73 (9th Cir. 1977) (requiring a more formalized approach to consideration of ''upsets beyond the control of the permit holder.''). Under the 2012 NSPS subpart OOOO affirmative defense provisions, if a source could demonstrate in a judicial or administrative proceeding that it had met the requirements of the affirmative defense in the regulation, civil penalties would not be assessed. Recently, the United States Court of Appeals for the District of Columbia Circuit vacated such an affirmative defense in one of the EPA's section 112(d) regulations. *NRDC* v. *EPA,* No. 10–1371 (D.C. Cir. April 18, 2014) 2014 U.S. App. LEXIS 7281 (vacating affirmative defense provisions in CAA section 112(d) rule establishing emission standards for Portland cement kilns). The court found that the EPA lacked authority to establish an affirmative defense for private civil suits and held that under the CAA, the authority to determine civil penalty amounts lies exclusively with the courts, not the EPA. Specifically, the court found: ''As the language of the statute makes clear, the courts determine, on a case-by-case basis, whether civil penalties are 'appropriate.' '' *See NRDC,* 2014 U.S. App. LEXIS 7281 at *21 (''[U]nder this statute, deciding whether penalties are 'appropriate' in a given private civil suit is a job for the courts, not EPA.'').[13] In light of *NRDC,* the EPA is proposing to remove the affirmative defense provisions from the 2012 NSPS subpart OOOO in this rulemaking. As explained above, if a source is unable to comply with emissions standards as a result of a malfunction, the EPA may use its case-by-case enforcement discretion to provide flexibility, as appropriate.

Further, as the D.C. Circuit recognized, in an EPA or citizen enforcement action, the court has the discretion to consider any defense raised and determine whether penalties are appropriate. *Cf. NRDC,* 2014 U.S. App. LEXIS 7281 *at *24.* (arguments that violation was caused by unavoidable technology failure can be made to the courts in future civil cases when the issue arises). The same logic applies to EPA administrative enforcement actions.

VII. Technical Corrections and Clarifications

Following publication of the 2012 NSPS and the 2013 storage vessel amendments, 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 that are editorial in nature, including typographical and grammatical errors, as well as incorrect dates and cross-references. Details of the specific changes we are proposing to the regulatory text may be found in the docket for this action.[14]

VIII. Impacts of This Proposed Rule

Our analysis shows that owners and operators of 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 or similar 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.

[13] The court's reasoning in *NRDC* focuses on civil judicial actions. The court noted that ''EPA's ability to determine whether penalties should be assessed for Clean Air Act violations extends only to administrative penalties, not to civil penalties imposed by a court.'' *Id.*

[14] Memorandum from Moore, Bruce, U.S. EPA, to Docket No. EPA–HQ–OAR–2010–0505, ''Technical Corrections to the Oil and Natural Gas Sector New Source Performance Standards.'' June 30, 2014

A. What are the air impacts?

We believe that owners and operators of 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 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 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 our analysis shows that owners and operators of 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 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 regulatory impacts analysis (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 proposed rule 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 Paperwork Reduction Act (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 Regulatory Flexibility Act (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 significant economic impact on a substantial number of small entities. In determining whether a rule has a significant economic impact on a substantial number of small entities, 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 significant economic impact on a substantial number of small entities 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 subject to this rule 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 *proposed rule* will not result in a significant economic impact on a substantial number of small entities. 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

This action contains no federal mandates under the provisions of Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 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 Risks 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 National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law No. 104–113, 12(d) (15 U.S.C. 272 note), directs the EPA to use voluntary consensus standards (VCS) in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. VCS 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, February 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

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

Dated: July 1, 2014.

Gina McCarthy,

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) introductory text 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 as determined according to this section by October 15, 2013 for Group 1 storage vessels and by April 15, 2014, or 30 days after startup (whichever is later) for Group 2 storage vessels, except as otherwise provided in this paragraph below. For storage vessels receiving liquids pursuant to the standards for gas well affected facilities in § 60.5375, including wells subject to § 60.5375(f), you must determine the potential for VOC emissions within 30 days after the beginning of the production stage as defined in § 60.5430. 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. The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in this section. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a Federal, State, local or tribal authority. For storage vessels not subject to a legally and practically enforceable limit in an operating permit or other requirement established under Federal, state, local or tribal authority, any vapor from the storage vessel that is recovered and routed to a process through a VRU designed and operated as specified in this section is not required to be included in the determination of VOC potential to emit for purposes of determining affected facility status, provided you comply with the requirements in paragraphs (e)(1) through (4) of this section.

* * * * *

■ 3. Section 60.5375 is amended by:

■ a. Revising paragraphs (a)(1) through (a)(3);

■ b. Revising paragraph (b);

■ c. Revising paragraphs (f)(1)(i), (ii) and (f)(2).

The revisions read as follows:

§ 60.5375 What standards apply to gas well affected facilities?

* * * * *

(a) * * *

(1) For each stage of the well completion operation, as defined in § 60.5430, follow the requirements specified in paragraph (a)(1)(i), (ii) or (iii) of this section as applicable.

(i) During the initial flowback stage, route the flowback into one or more well completion vessels and commence operation of a separator as soon as sufficient gas is present in the flowback for a separator to operate. Any gas present in the flowback prior to the separation flowback stage is not subject to control under this section.

(ii) During the separation flowback stage, route all liquids from the separator to one or more well completion vessels or storage vessels, or re-inject the liquids into the well or another well. Route the recovered gas from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. If it is infeasible to route the recovered gas as required above, follow the requirements in paragraph (a)(3) of this section. If, at any time during the separation flowback stage, the gas present in the flowback becomes insufficient to maintain operation of the separator, you must comply with (a)(1)(i) of this section. As soon as the rate of flowback has declined and stabilized enough to allow continuous recovery of the gas and to allow separation and recovery of any crude oil, condensate or produced water, you must comply with requirements for the production stage as provided in (a)(1)(iii) of this section.

(iii) During the production stage, separate and route recovered liquids to storage vessels. Route the recovered gas into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. During the production stage, recovered gas may not be vented or controlled by any combustion device.

(2) All salable quality gas must be routed to the gas flow line as soon as practicable. In cases where recovered gas cannot be directed to the flow line, you must follow the requirements in paragraph (a)(3) of this section.

(3) You must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous ignition source.

* * * * *

(b) You must maintain a log for each well completion operation at each gas well affected facility. The log must be completed on a daily basis for the duration of the flowback period and must contain the records specified in § 60.5420(c)(1)(iii).

* * * * *

(f) * * *

(1) * * *

(i) Each well completion operation with hydraulic fracturing at a wildcat or delineation well.

(ii) Each well completion operation with hydraulic fracturing at a non-wildcat low pressure gas well or non-delineation low pressure gas well.

(2) Route the flowback into one or more well completion vessels and commence operation of a separator as soon as sufficient gas is present in the flowback for a separator to operate. Any gas present in the flowback before the separator can operate is not subject to control under this section. You must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous ignition source. As soon as the rate of flowback has declined and stabilized enough to allow separation and recovery of any crude oil, condensate or produced water, route the recovered liquids to storage vessels. You must also comply with paragraphs (a)(4) and (b) through (e) of this section.

* * * * *

■ 4. Section 60.5385 is amended by:

■ a. Revising paragraph (a) introductory text; and

■ b. Adding paragraph (a)(3).

The revision and addition read as follows:

§ 60.5385 What standards apply to reciprocating compressor affected facilities?

* * * * *

(a) You must replace the reciprocating compressor rod packing according to either paragraph (a)(1) or (2) of this section or you must comply with paragraph (a)(3).

* * * * *

(3) Route the rod packing emissions to a process through a closed vent system and cover that meet the requirements of § 60.5411(a) and (b).

* * * * *

■ 5. Section 60.5390 is amended by revising paragraph (c)(2) to read as follows:

§ 60.5390 What standards apply to pneumatic controller affected facilities?

* * * * *

(c) * * *

(2) 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 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).

* * * * *

■ 6. Section 60.5395 is amended by:

■ a. Revising paragraph (d)(1)(i); and

■ b. Revising paragraph (f) introductory text.

The revisions read as follows:

§ 60.5395 What standards apply to storage vessel affected facilities?

* * * * *

(d) * * *

(1) * * *

(i) For each Group 2 storage vessel affected facility, you must achieve the required emissions reductions by April 15, 2014, or within 60 days after startup, whichever is later, except as otherwise provided below in this paragraph. For storage vessels receiving liquids pursuant to the standards for gas well affected facilities in § 60.5375, you must achieve the required emissions reductions within 60 days after the beginning of the production stage as defined in § 60.5430.

* * * * *

(f) *Requirements for storage vessel affected facilities that are removed from service.* If you are the owner or operator of a storage vessel affected facility that is removed from service, you must comply with paragraphs (f)(1) and (2) of this section. No other provision of this subpart applies to a storage vessel affected facility while that storage vessel affected facility is removed from service.

* * * * *

■ 7. Section 60.5401 is amended by revising paragraphs (d) and (e) to read as follows:

§ 60.5401 What are the exceptions to the equipment leak standards for affected facilities at onshore natural gas processing plants?

* * * * *

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of §§ 60.482–2a(a)(1) and 60.482–7a(a), and paragraph (b)(1) of this section.

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of §§ 60.482–2a(a)(1), 60.482–7a(a), and paragraph (b)(1) of this section.

* * * * *

■ 8. Section 60.5410 is amended by revising paragraph (d)(2) to 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?

* * * * *

(d) * * *

(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.

* * * * *

■ 9. 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 (b) introductory text;

■ e. Revising paragraph (b)(3); and

■ f. Revising paragraph (c) introductory text.

The revisions 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, reciprocating compressors and centrifugal compressor wet seal degassing systems?

* * * * *

(a) *Closed vent system requirements for reciprocating compressors and 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 reciprocating compressor or the wet seal fluid degassing system to a control device or to a process that meets the requirements specified in § 60.5412(a) through (c).

* * * * *

(b) *Cover requirements for storage vessels, reciprocating compressors and centrifugal compressor wet seal degassing systems.*

* * * * *

(3) Each storage vessel thief hatch shall be equipped with a mechanism or be of such design, and properly maintained and operated, to ensure that the lid remains 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 process.*

* * * * *

■ 10. Section 60.5412 is amended by revising paragraph (d) introductory text to 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?

* * * * *

(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 to paragraph (d)(1) of this section, 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).

* * * * *

■ 11. Section 60.5413 is amended by:

■ a. Revising paragraph (e) introductory text; and

■ b. Adding paragraph (e)(7).

The revisions and additions 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?

* * * * *

(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 (7) of this section.

* * * * *

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

* * * * *

■ 12. Section 60.5415 is amended by:

■ a. Revising paragraph (a)(2);

■ b. Revising paragraph (c) introductory text;

■ c. Adding paragraph (c)(4); and

■ d. Removing paragraph (h).

The revisions and additions 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?

* * * * *

(a) * * *

(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.

* * * * *

(c) For each reciprocating compressor affected facility complying with § 60.5385(a)(1) or (2), you must demonstrate continuous compliance according to paragraphs (c)(1) through (3) of this section. For each reciprocating compressor affected facility complying with § 60.5385(a)(3), you must demonstrate continuous compliance according to paragraph (c)(4).

* * * * *

(4) You must continuously comply with the closed vent and cover requirements in § 60.5411(a) and (b).

* * * * *

■ 13. Section 60.5416 is amended by:
■ a. Revising the section heading;
■ b. Revising the introductory text;
■ c. Revising paragraph (a) introductory text; and
■ d. Revising paragraph (b) introductory text.

The revisions read as follows:

§ 60.5416 What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my storage vessel, centrifugal compressor and reciprocating compressor affected facilities?

For each closed vent system or cover at your storage vessel, centrifugal compressor and reciprocating 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 or reciprocating 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.

* * * * *

(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 or reciprocating 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.

* * * * *

■ 14. Section 60.5420 is amended by:
■ a. Revising paragraphs (b)(6)(ii), (vi) and (vii); and
■ b. Revising paragraph (c)(3)(ii).

The revisions read as follows:

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

* * * * *

(b) * * *

(6) * * *

(ii) Documentation of the VOC emission rate determination according to § 60.5365(e) for each storage vessel that became an affected facility during the reporting period.

* * * * *

(vi) You must identify each storage vessel affected facility that is removed from service during the reporting period as specified in § 60.5395(f)(1), including the date the storage vessel affected facility was removed from service.

(vii) You must identify each storage vessel affected facility for which operation resumes during the reporting period as specified in § 60.5395(f)(2)(iii), including the date the storage vessel affected facility was returned to service.

* * * * *

(c) * * *

(3) * * *

(ii) Records of the date and time of each reciprocating compressor rod packing replacement, or the date of installation of a closed vent system as specified in § 60.5385(a)(3).

* * * * *

■ 15. Section 60.5430 is amended by:
■ a. Adding, in alphabetical order, definitions for the terms ''Initial flowback stage,'' ''Production stage,'' ''Recovered gas,'' ''Recovered liquids,'' ''Removed from service,'' ''Separation flowback stage,'' and ''Well completion vessel;''
■ b. Removing the definition of ''Affirmative defense;'' and
■ c. Revising the definition for ''Equipment'', ''Flowback'' ''Responsible official,'' ''Routed to a process or route to a process,'' and ''Storage vessel'' to read as follows:

§ 60.5430 What definitions apply to this subpart?

* * * * *

Equipment, as used in the standards and requirements in this subpart relative to the equipment leaks of VOC from onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by those same standards and requirements in this subpart.

* * * * *

Flowback means the process of allowing fluids and entrained solids to flow from a natural gas well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The term *flowback* also means the fluids and entrained solids that emerge from a natural gas well during the flowback process. The *flowback* period begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The *flowback* period ends when either the production stage begins or the well is shut in, whichever occurs first. Flowback includes the initial flowback stage and the separation flowback stage.

* * * * *

Initial flowback stage means the period during a well completion operation when there is insufficient gas in the *flowback* to operate a separator.

* * * * *

Production stage means the period during a well completion operation that follows the separation *flowback* stage when *flowback* has declined and stabilized sufficiently to allow continuous recovery of the gas and to allow separation and recovery of any crude oil, condensate and produced water. This definition applies to wells subject to § 60.5375(f) for purposes of determining a storage vessel's potential to emit VOC under § 60.5365(e).

* * * * *

Recovered gas means gas recovered through the separation process.

Recovered liquids means any crude oil, condensate or produced water recovered through the separation process.

* * * * *

Removed from service means that a storage vessel affected facility has been physically isolated and disconnected from the process for a purpose other than maintenance, has been completely emptied and degassed and is no longer used to contain crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty. If the storage vessel affected facility is reconnected to the process, or introduced with crude oil, condensate, produced water or intermediate hydrocarbon liquids at the same location, or relocated to another location and utilized as a storage vessel for crude oil, condensate, produced water or intermediate hydrocarbon liquids, it will be deemed to no longer be ''removed from service'' and at that time will be deemed ''returned to service'' and subject to the provisions of this subpart applicable to such vessel.

Responsible official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified in advance of delegation of authority to such representatives. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.,* a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

* * * * *

Separation flowback stage means the period during a well completion operation when a sufficient volume of gas is present in the *flowback* to operate a separator. The *separation flowback stage* ends when the production stage begins or when the well is shut in, whichever is first.

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. For the purposes of this subpart, the following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by § 60.5420(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.

* * * * *

Well completion vessel means a vessel that contains *flowback* during a well completion operation following hydraulic fracturing or refracturing. A well completion vessel may be a lined earthen pit, a storage vessel, or a vessel that is skid-mounted or portable.

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