ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2010–0505; FRL–9921–03–OAR]

RIN 2060–AR75

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

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: This action finalizes amendments to new source performance standards (NSPS) for the oil and natural gas sector. On August 16, 2012, the Environmental Protection Agency (EPA) published final NSPS 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 July 17, 2014 (79 FR 41752), the EPA published proposed amendments and clarifications as a result of reconsideration of certain issues related to well completions, storage vessels and other issues raised for reconsideration as well as technical corrections and amendments to further clarify the rule. This action finalizes these amendments and corrects technical errors that were inadvertently included in the final standards.

DATES: This final rule is effective on December 31, 2014.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2010–0505. 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.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy. 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) 685–3200; email address: *moore.bruce@epa.gov.*

SUPPLEMENTARY INFORMATION:

Organization of This Document. The information presented in this preamble is organized as follows:

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:

CAA Clean Air Act
CFR Code of Federal Regulations
CO_2 Carbon Dioxide
EPA Environmental Protection Agency
LEL Lower Explosive Limit
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
PTE Potential to Emit
psi Pounds per Square Inch
REC Reduced Emissions Completion
RFA Regulatory Flexibility Act
tpy Tons per Year
UMRA Unfunded Mandates Reform Act
VOC Volatile Organic Compounds
VRU Vapor Recovery Unit

II. General Information

A. Executive Summary

1. Purpose of This Regulatory Action

The purpose of this action is to finalize amendments to the 40 CFR part 60, subpart OOOO, Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution final rule promulgated under section 111(b) of the Clean Air Act (CAA), which was published on August 16, 2012 (77 FR 49490). Specifically, this final rule addresses certain issues 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 amending the NSPS to address these issues. Proposed amendments were published on July 17, 2014. (79 FR 41752)

2. Summary of Major Amendments to the NSPS

We are amending the standards for gas well affected facilities to provide greater clarity concerning what owners and operators must do during well completion operations with respect to the handling of gas and liquids during the well completion operations. In this action, we clarify that the flowback period of a well completion following hydraulic fracturing consists of two distinct stages, the ''initial flowback stage'' and the ''separation flowback stage.'' The initial flowback stage begins with the onset of flowback and ends when the flow is routed to a separator. During the initial flowback stage, any gas in the flowback is not subject to control. However, the operator must route the flowback to a separator unless it is technically infeasible for a separator to function. The point at which the separator can function marks the beginning of the separation flowback stage. During this stage, the operator must route all salable quality gas from the separator to a flow line or collection system, re-inject the gas into the well or another well, use the gas as an on-site fuel source or use the gas for another useful purpose. If it is infeasible to route the gas as described above, or if the gas is not of salable quality, the operator must combust the gas unless combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways. No direct venting of gas is allowed during the separation flowback stage. The separation flowback stage ends either when the well is shut in and the flowback equipment is permanently disconnected from the well, or on startup of production. This also marks the end of the flowback period. The operator has a general duty to safely maximize resource recovery and minimize releases to the atmosphere over the duration of the flowback period. The operator is also required to document the stages of the completion operation by maintaining records of (1) the date and time of the onset of flowback; (2) the date and time of each attempt to route flowback to the separator; (3) the date and time of each occurrence in which the operator reverted to the initial flowback stage; (4) the date and time of well shut in; and (5) date and time that temporary flowback equipment is disconnected. The NSPS already requires that the operator document the total duration of venting, combustion and flaring over the flowback period. All flowback liquids during the initial flowback period and the separation flowback period must be routed to a well completion vessel, a storage vessel or a collection system. On startup of production, the operator must begin the 30-day process of estimating the volatile organic compound (VOC) potential to emit (PTE) for storage vessels that will receive the liquids from the well. If the PTE is at least 6 tons/yr (tpy), the operator must control emissions from the storage vessel no later than 60 days after the startup of production (for storage vessels used in applications other than production following well completions, the term used to identify this point in time is ''startup''). A well completion vessel to which liquids from the well are routed after startup of production for a period in excess of 60 days is considered a ''storage vessel'' subject to the storage vessel PTE determination and, if determined to be a storage vessel affected facility, would be subject to the control, cover and closed vent system requirements of the NSPS.

We are finalizing the definition of ''low pressure gas well,'' as presented in the 2012 NSPS and re-proposed in the July 17, 2014, proposed rule.

We are finalizing several amendments related to the storage vessel provisions of the NSPS. First, we are finalizing provisions for determining VOC 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 tpy applicability threshold under a legally and practically enforceable permit or other limitation under federal, state or tribal authority. We are also amending the storage vessel closed vent system and cover requirements to allow use of other mechanisms besides weighted lid thief hatches to ensure that the thief hatch lid remains properly seated. In addition, we are amending the requirements for storage vessels to clarify notification and other requirements under the NSPS for storage vessels affected facilities that are removed from service for reasons other than maintenance. Further, we are clarifying that Group 1 and Group 2 storage vessel affected facilities that are removed from service are no longer affected facilities and therefore have no requirements under the NSPS until they are returned to service. The status of a Group 1 or Group 2 storage vessel that is later returned to service depends on its new use, which can fall into three possible scenarios. If the storage vessel is used to replace a storage vessel affected facility, or is being connected in parallel with a storage vessel affected facility, it is immediately subject to the same requirements as the affected facility being replaced or with which it is being connected in parallel. If the vessel is not used to replace or connected in parallel with an affected facility but is being used to contain crude oil, condensate, intermediate hydrocarbon liquids or produced water, it is allowed 30 days to determine if its VOC PTE is at least 6 tpy, and if so is subject to the requirements for Group 2 storage vessel affected facilities and would be required to control emissions no later than 60 days after return to service. If the vessel is being used in an application other than to contain crude oil, condensate, intermediate hydrocarbon liquids or produced water, it does not meet the definition of ''storage vessel'' and is not an affected facility under the NSPS.

We are amending 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 finalizing a third alternative that would allow routing emissions from the rod packing through a collection system under negative pressure via a closed vent system to a process.

We are finalizing 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 addition, we are amending 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 amending the provisions related to ''responsible official'' to remove any confusion by the regulated community with respect to the requirements for certifying under subpart OOOO and references to ''responsible official'' under the title V permitting program. To that end, we are changing the term ''responsible official'' to ''certifying official.'' We are also finalizing the proposed amendments to provide for delegation of authority after advance notification for facilities that employ 250 or fewer employees and have less than $25 million gross annual sales or expenditures (in second quarter 1980 dollars).

Finally, the EPA is removing a regulatory affirmative defense provision from the rule. 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.

3. Cost and Benefits

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 these amended 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 final rule that they would have for the original final rule, there should not be any incremental costs related to this final revision.

B. Does this reconsideration action apply to me?

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

TABLE 1—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS ACTION

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

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather is meant to provide a guide for readers regarding entities likely to be affected by this action. If you have any questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative as listed in 40 CFR 60.4 (General Provisions).

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 the final and proposed rules will be available on the WorldWide Web. Following signature, a copy of the rule will be posted at the following address: *http://www.epa.gov/airquality/oilandgas/actions.html.*

D. Judicial Review

Under section 307(b)(1) of the CAA, judicial review of this final rule is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit by March 2, 2015. Under section 307(d)(7)(B) of the CAA, only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Moreover, under section 307(b)(2) of the CAA, the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements. Section 307(d)(7)(B) of the CAA further provides that "[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review." This section also provides a mechanism for us to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, William Jefferson Clinton West Building, 1200 Pennsylvania Ave. NW., Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

III. Summary of Final Amendments

This section presents a summary of the provisions of the final action with brief explanations where appropriate. In some cases additional, detailed discussions are provided in sections IV or V. The final amendments include revisions to certain reconsidered aspects of the existing 2012 NSPS as follows: (1) Provisions for well completions that clarify and amend existing requirements for handling of flowback gases and liquids; (2) definition of "low pressure gas well"; (3) requirements pertaining to determining the potential emissions from storage vessels; (4) requirements for thief hatches; (5) provisions for storage vessels that are removed from service and for those that are returned to service; (6) provisions for 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) clarification of equipment subject to leak detection requirements under the NSPS; and (9) revised definition of "responsible official" and revision of the term to be "certifying official" for compliance certification purposes. In addition, we are removing the affirmative defense provisions from the startup, shutdown and malfunction provisions of the 2012 NSPS and are correcting technical errors in the 2012 NSPS. A summary of the final amendments resulting from our reconsideration is provided in the following paragraphs.

A. Well Completions

1. Handling of Flowback Gases and Liquids

In today's action we are finalizing requirements in § 60.5375 for handling of gases and liquids during flowback.

The regulatory language in the well completion provisions of § 60.5375 is amended to identify two distinct stages associated with well completion, with each stage having specific requirements for handling of gases and liquids. The final provisions are changed slightly from the proposed amendments in response to public comments. Discussion of our rationale for these changes since proposal are presented in section IV.A.

The flowback period consists of two stages, the "initial flowback stage" and the "separation flowback stage." The initial flowback stage begins with the first flowback from the well following hydraulic fracturing or refracturing and is characterized by high volumetric flow water, containing sand, fracturing fluids and debris from the formation with very little gas being brought to the surface, usually in multiphase slug flow. During this stage, the flowback must be routed to a ''storage vessel'' or to a ''well completion vessel'' that can be a frac tank, a lined pit or any other vessel. Our reason for this requirement is to avoid having operators route the flowback to an unlined pit or onto the ground. During the initial flowback stage, there is no requirement for controlling emissions from the vessel, and any gas in the flowback during this stage may be vented. However, the operator must route the flowback to a separator unless it is technically infeasible for a separator to function. As a result, we have changed ''as soon as sufficient gas is present in the flowback for a separator to operate'' to ''unless it is technically infeasible for a separator to function.'' We stress that operators have the responsibility to direct the flowback to a separator as soon as conditions allow a separator to function and in accordance with the General Provision requirements to operate the affected facility in a manner consistent with good air pollution control practices for minimizing emissions.

The second stage is defined as the ''separation flowback stage.'' The point at which the separator can function marks the beginning of the separation flowback stage. This stage is characterized by the separator operating with a gaseous phase and one or more liquid phases in the separator. During this stage, the operator must route all salable quality gas from the separator to a gas flow line or collection system, re-inject the gas into the well or another well, use the gas as an on-site fuel source or use the gas for another useful purpose that a purchased fuel or raw material would serve. If, during the separation flowback stage, it is infeasible to route the recovered gas to a flow line or collection system, reinject the gas or use the gas as fuel or for other useful purpose, the recovered gas must be combusted. No direct venting of recovered gas is allowed during the separation flowback stage except when combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways. With regard to infeasibility of collecting the salable quality gas, we believe that owners and operators plan their operations to extract a target product and evaluate whether the appropriate infrastructure access is available to ensure their product has a viable path to market before completing a well. However, there may be isolated cases in which, for reason(s) not within an operator's control, the well is completed and flowback occurs without a suitable flow line available. In those isolated instances, the NSPS provides a solution in § 60.5375(a)(3), which requires combustion of the gas unless combustion poses an unsafe condition as described above. During the separation flowback stage, all liquids from the separator must be directed to a storage vessel or to a well completion vessel, routed to a collection system or be re-injected into the well or another well.

The end of the separation flowback stage marks the end of the flowback period and is defined as the point at which the well is shut in and the flowback equipment is permanently disconnected from the well, or the startup of production. Identification of this point is discussed in detail in section IV.A. As provided in the 2012 NSPS, the operator has a general duty to safely maximize resource recovery and minimize releases to the atmosphere over the duration of the flowback period.

At some point following the end of the flowback period, depending on how long the well is shut in (if shut in), startup of production will occur. Depending on the situation, the operator may choose to startup production immediately following the end of flowback, once the well is temporarily shut in to remove flowback equipment, may begin production without shutting in and removing flowback equipment, or the operator might delay startup for some period of time by leaving the well shut in until permanent production equipment has been installed. Startup of production, whenever that occurs, marks the beginning of the 30-day period for determining VOC PTE for purposes of making a storage vessel affected facility determination in accordance with the procedure in § 60.5365(e). If the criteria in § 60.5365(e) are met, the operator would have to comply with the control requirements in § 60.5395(d)(1) within 60 days after the startup of production. During this period, any recovered liquids must be routed to well completion vessels, storage vessels or a collection system. A well completion vessel to which liquids are routed from the well for a period in excess of 60 days after startup of production would be considered a ''storage vessel'' under the NSPS and, depending on its VOC PTE, would be subject to the control, cover and closed vent system requirements for storage vessel affected facilities. We are finalizing amendments to § 60.5365(e) to reflect that, for storage vessels associated with production following completions, the 30-day period for the affected facility determination required § 60.5365(e) commences on startup of production. We are also amending the requirements for storage vessel affected facilities in § 60.5395(d)(1)(i) to reflect that, for purposes of the well completion provisions, control is required no later than 60 days from startup of production.

To accompany these changes, we are also amending the reporting and recordkeeping requirements in § 60.5420 to revise the terminology used in that section relating to periods of gas recovery, combustion and venting to be compatible with the terms used in the final clarifying amendments to § 60.5375, including addition of a requirement to document the time of the beginning of flowback, the time at which the operator directs the flowback to a separator (each time this is done), the reason for reverting back to the initial flowback stage (if this is done), the time of well shut in and removal of flowback equipment (end of the flowback period) and time of startup of production (beginning of the PTE determination period). We are also revising the language used in requirements for exploratory, delineation and low pressure wells in § 60.5375(f) to be consistent with the final amended terminology and requirements in § 60.5375(a).

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

We are finalizing the re-proposed 2012 EPA definition of ''low pressure gas well'' without change. This definition is used in conjunction with § 60.5375(f), which provides that those wells for which a reduced emissions completion (REC) would not be feasible because of a combination of well depth, reservoir pressure and flow line pressure is not required to meet the requirements for recovery of gases and liquids required under § 60.5375(a). Instead of having to perform an REC and recover gas during the separation flowback stage, operators performing completions of low pressure gas wells (in addition to wildcat wells and delineation wells) are required only to combust the gas rather than capture it during flowback. The 2012 NSPS included 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 of ''low pressure gas well'' is found in § 60.5430.

Following publication of the final rule, several petitioners for administrative reconsideration (hereinafter ''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. In the July 17, 2014, proposed rule, we re-proposed the 2012 definition and solicited comment on an alternative definition provided by these petitioners.[1] For the reasons discussed in detail in section V.A, we are retaining the 2012 definition without change.

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 filed additional administrative reconsideration petitions, in which they raised issues with regard to various provisions of the 2013 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

We are finalizing amendments to § 60.5365(e) to allow the PTE exclusion provision only in cases where a storage vessel is not subject to any legally and practically enforceable limitation or other requirement under a federal, state, local or tribal authority. An owner or operator invoking this exclusion provision must comply with the provisions of § 60.5365(e)(1) through (4) in determining VOC PTE for purposes of determining affected facility status.

2. Thief Hatch Properly Seated

We are finalizing amendments to § 60.5411(b)(3) to require that thief hatches be equipped, maintained and operated with a weighted mechanism or equivalent, to ensure that the lid remains properly seated. This amendment provides for proper seating of thief hatch lids while allowing innovation and flexibility in design not afforded by requiring that thief hatch lids be weighted.

3. Storage Vessels Removed From Service

As proposed, we are amending § 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.

For the reasons discussed in detail in section IV.B, we are also amending the NSPS to clarify that a Group 1 and Group 2 storage vessel affected facility that is removed from service, which is defined in § 60.5430 as physically isolated and disconnected from the process for a purpose other than maintenance and, pursuant to § 60.5395(f)(1), completely emptied and degassed and no longer used to contain crude oil, condensate, produced water or intermediate hydrocarbon liquids, would no longer meet the definition of ''storage vessel'' in § 60.5430 and, therefore, cease to be affected facilities under the NSPS for the period they are out of service.

We are also amending the NSPS to provide that a Group 1 or Group 2 storage vessel affected facility that is returned to service is subject to the NSPS based on the use of the vessel in its new application. There are three possible scenarios for vessels returned to service: (1) The vessel is used to replace a storage vessel affected facility or is connected in parallel with a storage vessel affected facility; (2) the vessel is not used to replace an affected facility but is being used to contain crude oil, condensate, intermediate hydrocarbon liquids or produced water; or (3) the vessel is being used in an application other than to contain crude oil, condensate, intermediate hydrocarbon liquids or produced water. If the vessel is being used to replace a storage vessel affected facility or is connected in parallel with a storage vessel affected facility (*i.e.,* the liquid contents and the VOC PTE are already known), then it is a storage vessel affected facility and immediately upon startup would be subject to the same requirements as the storage vessel affected facility being replaced. If the vessel is not being used to replace an affected facility but is being used to contain crude oil, condensate, intermediate hydrocarbon liquids or produced water (*i.e.,* the VOC PTE is unknown), then, just as for any new storage vessel, the operator would be afforded a 30-day period after startup to determine the storage vessel's affected facility status based on VOC PTE and, if VOC PTE were estimated to be at least 6 tpy, the storage vessel would be determined an affected facility and would be subject to requirements for Group 2 storage vessels, and controlled no later than 60 days after startup. If the vessel is not being used to contain crude oil, condensate, intermediate hydrocarbon liquids or produced water, it does not meet the definition of ''storage vessel'' and would not be subject to the requirements of the NSPS.

We are amending the definition of ''removed from service'' and adding a definition of ''returned to service'' to clarify these provisions. See section IV.B for a detailed discussion.

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

The 2012 final NSPS includes operational or ''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 that asserted that an alternative technology exists that would reduce emissions commensurate with or better than the reductions from the operational standard. This 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, or other process that would burn the gas as fuel to augment the normal fuel supply. 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 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 and, therefore, it would be within the operator's discretion to choose whichever option is most appropriate for the application and situation at hand.

Therefore, for the above reasons and as discussed in the proposed rule, we are revising § 60.5385(a) to include a third option for routing the rod packing emissions to a process through a closed

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

vent system that meets the requirements of § 60.5411(c).

Also as proposed, we are amending 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). Similarly, we are amending the continuous compliance requirements in § 60.5415 and inspection and monitoring requirements in § 60.5416 to apply to reciprocating compressors.

The EPA received comments in support of the addition of the third alternative in § 60.5385(a). However, commenters identified several inconsistencies that should be addressed with respect to other provisions as they relate to the revised § 60.5385(a). The EPA agrees with the commenters' rationale and is amending §§ 60.5410(c)(1), 60.5415(c)(4), 60.5416(a), and 60.5420(c)(6) through (9) to be consistent with the intent of the third alternative provision in § 60.5385(a)(3). Specifically, we are revising the initial compliance demonstration provisions in § 60.5410(c)(1) by adding language such that paragraphs (c)(1) through (4) would not apply to sources electing to comply with § 60.6385(a)(3). The EPA agrees with commenters that these provisions would not apply to sources that are operating a closed vent systems and complying with § 60.5385(a)(3). We are revising the continuous compliance demonstration provisions in § 60.5415(c)(4) to reflect that the source must comply with 60.5416(a) and (b) rather than § 60.5411(a) and (b). The EPA agrees that the provisions of § 60.5416(a) and (b) are more appropriate for a reciprocating compressor operating with a closed vent and cover system. We are amending § 60.5420(c)(6) through (9) to add reciprocating compressors as sources subject to these recordkeeping requirements.

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 of field gas per day) and at natural gas processing plants located on the Alaskan North Slope. With the exception of the revision to lower the leak definition for valves, we retained the other provisions of subpart KKK by adopting the subpart KKK regulatory text, including the above mentioned exemptions, in subpart OOOO. With this complete adoption of subpart KKK regulatory text on the exemptions, we inadvertently failed to update the equipment list to include connectors, as pointed out by petitioners. 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 these requirements. As a result, as proposed, we are amending § 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 natural gas processing plants, which was the scope of subpart KKK. Except for lowering the leak definition for valves and requiring monitoring of connectors, subpart OOOO retains the other provisions of the subpart KKK by adopting those provisions, including the definition of ''equipment.'' 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 affected facility under the entire subpart OOOO, including those not located at onshore natural gas processing plants. To avoid any such misinterpretation, we are amending the definition of ''equipment'' in § 60.5430 to read as set forth in the regulatory text of this rule.

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.

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. Therefore, consistent with the proposed changes, we are also amending the definition 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).

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 the process of this evaluation, we also determined that the use of ''permitting authority'' and the ''responsible official'' are similar to terms used in the requirements of the Title V permitting program. In order to remove potential confusion by the regulated community and to clarify that this is a requirement of the NSPS and is not associated with a permitting program, we are changing the term ''responsible official'' to ''certifying official'' and replacing the term ''permitting authority'' used in the definition with ''Administrator.''

F. Affirmative Defense

The EPA is removing a regulatory affirmative defense provision from the rule, as proposed. For the reasons stated in the preamble to the proposed amendments and below, we are finalizing the removal of the affirmative defense provisions. In the 2012 rulemaking, the EPA had included an affirmative defense to civil penalties for violations caused by malfunctions in 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 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 EPA's regulatory 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 an affirmative defense in one of the EPA's section 112 regulations. *NRDC* v. *EPA,* 749 F.3d 1055 (D.C. Cir., 2014) (vacating affirmative defense provisions in section 112 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 in such cases 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,* at 1063 (''[U]nder this statute, deciding whether penalties are 'appropriate' in a given private civil suit is a job for the courts, not EPA.'').[2] In light of *NRDC,* the EPA had proposed and is finalizing in this action the removal of the regulatory affirmative defense provisions in subpart OOOO. 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,* at 1064 (arguments that violation were caused by unavoidable technology failure can be made to the courts in future civil cases when the issue arises). The same is true for the presiding officer in EPA administrative enforcement actions.[3]

IV. Summary of Significant Changes Since Proposal

Section III summarized the amendments to the 2012 NSPS that the EPA is finalizing in this rule. This section discusses the key changes the EPA has made since proposal. These changes are the result of the EPA's consideration of the many substantive and thoughtful comments submitted on the proposal and other information received since proposal. We believe that the changes we have made sufficiently address concerns expressed by commenters and improve the clarity of the rule while improving or preserving public health and environmental protection required under the CAA.

A. Well Completions

1. Handling of Flowback Gases and Liquids

In today's action we are finalizing clarifications and amendments to provisions for handling of gases and liquids during flowback at § 60.5375. Following publication of the 2012 final NSPS, we received feedback from petitioners that the well completion provisions were unclear and that operators were not sure of the requirements for handling of gas and liquids during well completion operations. Petitioners also asserted that, as written, compliance with the 2012 NSPS was impossible, since the rule appeared to prohibit venting of gas at any time during the well completion. In our July 17, 2014, proposal, we clarified it was not the EPA's intent to prohibit venting of flowback gases throughout the entire flowback period and 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 after separation. We confirmed that the initial flowback (prior to recovery of gas from the liquids through separation) may be routed to storage vessels, temporary fracture tanks (frac tanks) or to lined pits, as long as separation and recovery of the gas 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).

To clarify EPA's intent with regard to handling of gas and liquid portions of flowback, we had proposed three distinct stages of the completion operation, with each stage having specific requirements for handling of gases and liquids.

As proposed, the first stage would begin with the first flowback from the well following hydraulic fracturing or refracturing, and would be 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. Under the proposed amendments, the first stage was defined as the ''initial flowback stage.'' We had proposed that during this stage the flowback would be required to be routed to a ''well completion vessel'' that could be a frac tank, a lined pit or any other vessel. Our intention was that the flowback could not be directed to an unlined pit or onto the ground. During the initial flowback stage, there would be no requirement for controlling emissions from the tank or other vessel, and any gas in the flowback during this stage could be vented. We proposed that, as soon as sufficient gas is present in the flowback for a separator to operate, the flow would be required to be diverted to the separator. We explained that ''for a separator to function enough gas must be flowing [in the flowback] to maintain a gaseous phase and one or more liquid phases in the separator.'' (79 FR 41755). In the proposal preamble, we had

[2] 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.*

[3] Although the *NRDC* case does not address the EPA's authority to establish an affirmative defense to penalties that is available in administrative enforcement actions, EPA had not included such an affirmative defense in the 2012 NSPS. As explained above, such an affirmative defense is not necessary. Moreover, assessment of penalties for violations caused by malfunctions in administrative proceedings and judicial proceedings should be consistent. *Cf.* CAA section 113(e) (requiring both the Administrator and the court to take specified criteria into account when assessing penalties).

discussed how some operators monitor the gas concentration at the vessel receiving the flowback both for safety reasons and to determine that sufficient gas is present in the flowback for the separator to function. We understood that when the gas concentration approaches the lower explosive limit (LEL) (*i.e.,* approaches flammability), these operators direct the flowback to a separator. We were uncertain whether this method could be used effectively in all applications and whether there were other techniques used by operators to make this determination. We solicited comment on the suitability of the ''LEL method'' when used for this purpose and asked for information on other techniques or indicators that could be used to determine when sufficient gas is present for a separator to function.

Commenters responded that the EPA apparently had misunderstood earlier discussions regarding use of the LEL detector. They asserted that the detector is used for safety reasons and that although the LEL detector indicates that there may be potential flammability, it does not necessarily indicate that sufficient gas is present for the separator to function. Commenters also asserted that monitoring the gas concentration does not reflect other conditions such as sand and water content and well characteristics that have a bearing on the point where the separator will operate. We also learned that some operators begin to direct the flowback to the separator immediately upon initial flowback, even though it may not maintain a gaseous phase and one or more liquid phases in the separator. Other operators may not have an initial flowback stage and may go directly to the separation flowback stage.

Because whether a separator can operate may depend on site specific factors other than the amount of gas present in the flowback, we are not finalizing the proposed requirement to commence operation of a separator as soon as sufficient gas is present in the flowback for a separator to operate. However, the public comments did not provide sufficient information regarding other indicators as to when a separator can operate. We therefore are unable to establish specific criteria for determining the point at which operators are required to route the flowback to the separator. For the reasons stated above, we require in the final amendments that flowback must be routed to a separator unless it is technically infeasible. This has always been our intent. Although we learned that technical infeasibility is not strictly limited to the amount of gas present, we believe that if this infeasibility is not predicated solely on the amount of gas present, then there must be some other site-specific technical issues that prevent a separator from functioning. Such technical infeasibility might include the separator being overwhelmed by the flowback, such that the vapor space in the separator is not maintained, or the liquid drain is unable to handle the volume of liquid flowing through. We further note that the general duty to maximize resource recovery and minimize releases to the atmosphere required in § 60.5375(a)(4) applies during the entire flowback period, including the initial flowback stage.

As proposed, the second stage, defined as the ''separation flowback stage,'' begins when the flowback gases and liquids are routed to 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 infeasible to route the recovered gas to a flow line or collection system, 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, as required in the 2012 NSPS at § 60.5375(a)(3). No direct venting of recovered gas would be allowed during the separation flowback stage. We also proposed that, at any time during the separation flowback stage, if the gas present in the flowback becomes insufficient to maintain operation of the separator, the operator would revert to the initial flowback stage until the separator could again function to allow continuous recovery of the gas and to allow separation and recovery of the liquids. 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. We are finalizing the provisions relative to the separation flowback stage as proposed, except that the operator can revert to the initial flowback stage if it is technically infeasible to maintain function of the separator (consistent with our discussion above on requiring the operation of a separator unless it is technically infeasible). We also have added requirements for recordkeeping to document each occurrence of reverting back to the initial flowback stage and the reason for the reversion.

We had proposed that the end of the separation flowback stage was the point where separation flowback would have declined and stabilized enough to allow continuous recovery of the gas and where separation and recovery of any crude oil, condensate and produced water were possible. We had proposed that the flowback period of a well completion operation included only the initial flowback stage and the separation flowback stage, as flowback ended and ongoing production began at that point. Further, we had identified that point as the beginning of the ''production stage'' of the well completion. We had also explained at proposal that we were seeking to identify objective criteria for making a determination that flowback had subsided and that the well had reached the point where production could begin, marking the end of the separation flowback stage and the beginning of the production stage. We solicited comment on the characteristics of the flow or other conditions that could be used to establish such criteria.

In addition, we proposed that, for storage vessels receiving liquids following the flowback period of a well completion, the beginning of the production stage would also begin the 30-day period for determining VOC PTE 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 had also proposed amendments to § 60.5365(e) to reflect that, for purposes of the well completion provisions, the 30-day period for the affected facility determination required in § 60.5365(e) would commence at the beginning of the production stage. During the production stage, any venting or flaring of the recovered gas would be prohibited.

Several commenters took issue with the inclusion of the production stage as part of the overall well completion operation. The commenters contended that this extension confuses or contradicts other provisions that explicitly are applicable to well completion operations and should not be applicable over the lifetime of a well in production. The commenters asserted that it is critical that the rule identify when the flowback period ends and clarify that the requirements for well completions do not extend beyond the end of the flowback period. The commenters explained that, because the production stage could conceivably continue for decades, it was clearly not a stage of well completion and was beyond the intended scope of § 60.5375. Commenters also gave examples of the ramifications of this concept. They asserted that prohibition of venting and flaring for the lifetime of the well would preclude planned maintenance workovers, flaring of amine system overhead gas and venting of carbon dioxide.

We agree with the commenters that the production stage should not be a stage of well completion and understand that compliance with the well completion provisions (which were intended only for the flowback period) would be impossible were these provisions applicable throughout the life of the well. As a result, we are finalizing requirements for well completions that identify two stages of well completion, the initial flowback stage and the separation flowback stage.

As discussed above, we had proposed that the point where separation flowback would have declined and stabilized enough to allow continuous recovery of the gas and where separation and recovery of any crude oil, condensate and produced water were possible would be the end of the separation flowback stage and the beginning of the production stage. We solicited information that could identify criteria for defining this point. Commenters explained that removal of flowback equipment and absence of well completion personnel were two indicators that flowback had subsided and the well had cleaned up sufficiently to allow production to begin.

In addition to the information provided by commenters, it is our observation that the permanent disconnection of the temporary equipment used during flowback can be an indicator of flowback having ended. For example, during flowback, skid-mounted choke manifolds are used to limit flowback and assist in directing the flow. Temporary lines laid on the ground from the wellhead to the choke manifold and to the flowback separators and frac tanks are connected with ''hammer unions'' which are pipe unions that are designed for ease of making temporary connections and are characterized by ''ears'' that allow the joint to be made up quickly by striking with a hammer. After flowback has subsided and the well has cleaned up sufficiently, the well is temporarily shut in to disconnect the temporary flowback equipment. We believe that when the operator permanently disconnects choke manifolds, temporary separators, sand traps and other equipment connected with temporary lines and hammer unions, it is a reliable indicator that flowback has ended and the well is ready for production. At that point, we believe that operators will remove these temporary equipment used during flowback to avoid incurring unnecessary charges for additional days the equipment remains onsite. The well could start production immediately or it could remain shut in until permanent equipment is installed some time later.

In light of the above considerations, we are amending the NSPS such that the end of the separation flowback stage is defined as the startup of production, or when the well is shut in and the temporary flowback equipment has been permanently disconnected from the well. We are also finalizing amendments that identify the startup of production, rather than the beginning of the production stage, as the beginning of the 30-day period for determining storage vessel PTE according to the requirements of § 60.5365(e).

As discussed in section V.A, we had received comment that some operators route gas and liquids from the well site to other facilities for collection and suggested we specify ''collection system'' as one of the options for disposition of flowback liquids and recovered gas. We agree with the commenter and have included ''collection system'' in the provisions for gas and liquids handling during well completions. To provide clarity, we also have added a definition in § 60.5430 for ''collection system'' which is presented in section V.A.

We are finalizing the liquids handling requirements during the flowback period as proposed, with the slight revision to the definition of the separation flowback stage as described above. During the flowback period, which includes the initial flowback stage and the separation flowback stage, the liquid portion of the flowback must be directed to storage vessels, well completion vessels, injected into the well or another well or routed to a collection system.

In the proposed rule, we had provided that the 30-day period for estimating the VOC PTE of a storage vessel receiving recovered liquids would begin at the beginning of the production stage. With the revision to the stages of completion discussed above, ''startup of production'' would replace ''beginning of the production stage.'' Because we believe it is important to achieve control of storage vessel affected facilities as soon as practicable, we believe it is important to begin the 30-day period for estimating storage vessel VOC PTE as soon as this estimation can be achieved and will provide a representative estimate of the storage vessel's PTE during production. As a result, we believe it is necessary to begin the estimation period after flowback ends, immediately after the end of the separation flowback stage, since the flowback period is not representative of liquids flow and composition during production. Estimation during the flowback period could result in PTE estimates being either abnormally low or abnormally high, since very early in flowback the liquid is predominantly water flowing at a high rate, while immediately after flowback, the volume has subsided but VOC content of the liquid may be much higher. Tank emission estimation methods generally require information on both the composition of the liquid entering a storage vessel (generally obtained through analysis of a pressurized sample of the liquid obtained from the separator) and the volumetric rate of the liquid (often in barrels per day). Because the analytical samples are taken from the separator and the volume is calculated by recording the liquid collection from the receiving vessel, it is not necessary to have a permanent storage vessel installed in order to perform this estimation, and the sampling and volume tracking can begin at any time after the end of flowback, while the liquids are being collected in a well completion vessel or a storage vessel. Based on these considerations, we are finalizing the requirement that liquid during flowback may be routed to a well completion vessel or storage vessel. Also, based on these considerations, we are clarifying that recovered liquids may continue to be routed to a well completion vessel or a storage vessel after the startup of production, but that a well completion vessel to which recovered liquids are routed for a period in excess of 60 days after startup of production is considered a storage vessel subject, depending on its PTE, to control under § 60.5395, as with any other storage vessel affected facility. In addition, we are amending the definitions of ''storage vessel'' and ''well completion vessel'' to be consistent with this requirement. We are amending § 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 startup of production. Consistent with these changes we are amending § 60.5395(d)(1)(i) to read as set forth in the regulatory text of this rule.

We note that we have received requests for clarification of the meaning of ''maximum average daily throughput'' as used in the VOC PTE determination language in § 60.5365(e). The 2013 final rule that promulgated storage vessel implementation amendments in which this term first appeared in the NSPS provided limited guidance on how operators should determine ''maximum average daily throughput,'' and no definition of this term was included in the July 2014 proposed rule. The discussion above explains that PTE determination methods generally are based on modeling performed using results of analysis of pressurized samples from the separator combined with liquid throughput over some period that corresponds with the separator sample. We believe that the ''maximum average daily throughput'' is determined by the earliest calculation of daily average throughput during the 30-day evaluation period employing generally accepted methods. Based on the performance of wells over time, this initial calculation would represent the maximum average daily throughput that could be expected for the storage vessel. To provide more clarity in the rule, we have added a definition of ''maximum average daily throughput'' in § 60.5430. We are aware that issues remain concerning this term and continue to consider how to resolve them.

B. Storage Vessels

1. Storage Vessels Removed From Service and PTE Determination

As proposed, we are amending § 60.5395(f) 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.

For the reasons discussed below, we are also amending the NSPS to clarify that storage vessel affected facilities removed from service (which is defined as when they are physically disconnected from their source of liquids for reasons other than maintenance and are emptied and degassed) cease to be storage vessel affected facilities under the NSPS. We received comment, with which we agree, that storage vessel emissions are a function of the specific use of the vessel as installed—determined by factors such as the type of liquid it is used to contain, the liquid throughput of the vessel, and the pressure drop of the liquid entering the vessel causing flash emissions. As a result, removing a storage vessel from service in one use and moving it to a new use could drastically change its emissions characteristics. To be classified a ''storage vessel'' as defined in § 60.5430, a tank or other vessel must be used to contain crude oil, condensate, intermediate hydrocarbon liquids or produced water. Should the tank or other vessel cease being used to contain any of these liquids, it would no longer meet the definition of ''storage vessel.'' In light of these considerations, we believe that a storage vessel affected facility that 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 should not be subject to requirements under the NSPS for the period of time it is removed from service.

A vessel, whether it is in service for the first time or after being removed from service, falls into one of three categories: (1) It is installed to replace a storage vessel affected facility or is connected in parallel with a storage vessel affected facility, where liquids to be contained and VOC PTE for the application are already known; (2) the vessel does not replace a storage vessel affected facility but is being returned to service to contain crude oil, condensate, intermediate hydrocarbon liquids or produced water with unknown PTE; or (3) the vessel is being used in an application other than to contain crude oil, condensate, intermediate hydrocarbon liquids or produced water.

A vessel falling under the first category, that is replacing or is being connected in parallel with a vessel that has already been determined to be a ''storage vessel affected facility'' based on a known PTE, in effect takes the place of the affected facility being replaced or with which it is being connected in parallel and, as such, should be immediately subject to the same requirements as the storage vessel affected facility being replaced. There is no need for the 30-day period after startup allowed under § 60.5365(e) for determining its VOC PTE and the 60-day period after startup allowed under § 60.5395(c) for applying control. In short, a vessel in this category should be subject immediately upon startup to the same requirements as the storage vessel affected facility it is replacing. For example, a vessel that is replacing a storage vessel affected facility subject to the 95.0 percent control requirement in § 60.5395(d)(1) would be subject to § 60.5395(d)(1), whereas a vessel that is replacing a storage vessel affected facility subject to the 4 tpy alternative uncontrolled emission standard in § 60.5395(d)(2) would be subject to § 60.5395(d)(2).

For vessels in the second category, *i.e.,* the vessel does not replace a storage vessel affected facility but is being returned to service to contain crude oil, condensate, intermediate hydrocarbon liquids or produced water with unknown PTE, the 30-day period for determining the VOC PTE and the 30-day period for installation of control if the PTE is 6 tpy or above would apply.

For vessels in the third category, *i.e.,* the vessel is being used in an application other than to contain crude oil, condensate, intermediate hydrocarbon liquids or produced water, the vessel continues to not meet the definition of ''storage vessel'' for this rule and has no requirements while in this service.

Although we believe it is an unlikely occurrence, we note that, when two or more storage vessels receive liquids in parallel, the total throughput is shared between or among the parallel vessels and, in turn, this causes the PTE of each vessel to be a fraction of the total PTE. In these cases, the EPA would consider the parallel storage vessels equivalent to a single vessel with PTE equal to the sum of the PTE of the individual vessels. As a result, the parallel storage vessels would be considered storage vessel affected facilities and subject to control if the total PTE was at least 6 tpy. If one of the parallel storage vessels has already been determined to be an affected facility and is subject to storage vessel requirements, no PTE calculation is necessary for the other parallel storage vessels because the PTE is already known to be at least 6 tpy. In that event, all storage vessels receiving liquids in parallel to the storage vessel affected facility are subject to the same requirements immediately upon startup. As a result of the above considerations, we are amending the current definition of ''removed from service'' and adding a definition of ''returned to service'' to clarify these provisions. The definitions read as set forth in the regulatory text of this rule.

We are also amending § 60.5395(f) to include requirements for storage vessels removed from service and returned to read as set forth in the regulatory text of this rule.

C. Definition of ''Responsible Official''

In our proposed action, the EPA proposed to amend the definition of ''responsible official'' to address several concerns identified by petitioners as discussed above in section III.E. In our evaluation of comments received from regulatory authorities and industry, we determined that the terminology used for the definition of ''responsible official'' too closely mirrored terminology used in the Title V permitting program. As the requirements of subpart OOOO are separate and distinct from those of any permitting program, we found that the use of those terms was inappropriate for subpart OOOO and could potentially cause confusion of regulated entities. Therefore, in addition to the proposed change to the definition to reduce the burden of the advance delegation requirements on the oil and gas industry, we are changing the term ''responsible official'' to ''certifying official'' and changing the term ''permitting authority'' used in the definition to ''Administrator.''

V. Summary of Significant Comments and Responses

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

A. Well Completions

1. Handling of Gases and Liquids

Comment: One commenter concurs that many wells undergo the three stages of well completion as defined in the preamble to the proposed rule, but not all wells. The commenter points to the Fayetteville Shale where the flowback from many of their wells are routed directly to a separator with gas recovered into gathering lines and produced water sent to frac tanks and then to lined earthen retention ponds. The commenter asserts that these wells do not undergo the initial flowback stage nor the separation flowback stage and instead go directly into production stage as defined in the proposed rule.

Response: The EPA acknowledges that there are differences in reservoir characteristics and the resultant variations in composition of the flowback between shale plays and even within a given shale play. These differences affect how the well completion process is conducted. As we discussed in section IV.A, we are aware that some operators are able to route the flowback directly to a separator, essentially bypassing the initial flowback stage. We agree with the commenter that this is possible in some cases; however, that may not be true for all situations. The final rule requires operators to direct the flow to the separator unless it is technically infeasible for the separator to function (which we explain in further detail in section IV.A) and minimize releases to the atmosphere as required by § 60.5375(a)(4). We disagree with the commenter that their operation bypasses both stages of flowback, if the operations the commenter described used a temporary separator or other temporary flowback equipment. If a temporary separator or other temporary flowback equipment were used, then the operation would bypass the initial flowback stage but enter the separation flowback stage and would be subject to the requirements of § 60.5375(a)(1)(ii). If such temporary flowback equipment is not used, then the completion operation is indeed considered to enter directly into production at the beginning of flowback, which in this case would be considered ''startup of production,'' that begins the 30-day period for determining VOC PTE for purposes of making a storage vessel affected facility determination in accordance with the procedure in § 60.5365(e). However, should the well completions described by the commenter involve the use of temporary flowback equipment, then the onset of flowback would begin the separation flowback stage, which would continue until the well was shut in and the temporary flowback equipment was removed. There would be no initial flowback stage in either case described above.

Comment: One commenter supports the EPA's proposed definition of initial flowback stage because they have received information in the subpart OOOO annual reports that control was not possible or necessary because there was insufficient gas to route to a control device. Further, to ensure that emissions are not unnecessarily vented, the commenter supports the EPA's establishment of clear criteria for determining when there is sufficient gas to operate the separator, as well as the delineation between the initial and separation flowback stages. The commenter is concerned that without additional, clear criteria, operators will unnecessarily vent rather than control emissions. The commenter, therefore, requests that the EPA clarify the criteria for reversion to initial flowback stage from separation flowback stage when the recoverable gas present in the flowback becomes insufficient to maintain operation of the separator.

Response: As stated above, under the final rule, the second stage, defined as the ''separation flowback stage,'' begins when the flowback is routed to the separator, which is required unless it is technically infeasible. The issues raised by the commenter are discussed in depth in sections III.A and IV.A.

Comment: One commenter expressed concern with the proposed definition of the separation flowback stage which states that ''the separation flowback stage ends when the production stage begins or when the well is shut in, whichever is first.'' The commenter contends that the well shut in provision should be removed. The commenter states that in a typical well completion operation, prior to commencing production, the well may be shut in to remove the flowback equipment and install production equipment. In some instances, the well may be temporarily shut in for other purposes such as making adjustments or performing unexpected maintenance on the flowback equipment. Following these activities, the well is re-opened and separation flowback may resume. According to the commenter, the proposed rule would consider the well in the ''production stage'' when the well is shut in regardless of whether it actually enters into production or returns to the flowback process after temporary shut in. The commenter believes it is more accurate for the rule to state that the end of the separation flowback stage occurs when production (not the ''production stage'') begins. The commenter provides suggested revisions to the definition for *separation flowback stage.*

Response: The EPA agrees with the commenter that a well may be shut in for various reasons and that shut in alone does not necessarily depict the point of transition into production. As described in detail in section IV.A, there are other conditions such as having the temporary flowback equipment disconnected that indicate the end of flowback that should be taken into account in combination with well shut in. Further, although this commenter did not raise this issue, as discussed in an earlier response, sometimes operators can startup production without shutting in the well by running the temporary flowback equipment in parallel with the permanent flow line such that they can open the valve from the wellhead to the flow line and close the valve from the wellhead to the temporary flowback equipment, and isolate the temporary equipment for removal. As a result, the well is not shut in, but the temporary flowback equipment would be removed. In such cases, production had started without well shut in. In light of the above, in the final rule, we have defined the ''separation flowback stage'' to include two sets of criteria which identify the end of the separation flowback stage. The new definition indicates that the end of the separation flowback stage ends at the startup of production, or when the well is shut in and permanently disconnected from the flowback equipment. Therefore, a shut in condition of the well alone will not be considered the end of the separation flowback stage so long as flowback equipment is still connected and production has not begun.

Comment: One commenter points out that there is a point at which gas can be separated from fluids, but the gas is not yet of salable quality. The commenter recommends that the EPA allow flaring of non-sales quality gas because it cannot be recovered and sold, and recommends that § 60.5375 be amended to refer to ''salable quality'' gas from the gas outlet of the separator and similar changes to the definitions of ''production stage,'' ''recovered gas'' and ''reduced emissions completion'' in § 60.5430.

Another commenter states that § 60.5375(a)(2) specifies only one of the suitable options for salable quality recovered gas. The commenter suggests that this section be modified to say ''all salable quality recovered gas must be routed to a gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve.'' Alternatively, this paragraph could be deleted in that it is redundant given § 60.5375(a)(1)(ii).

Response: The EPA agrees with the commenter's assertion that some gas recovered during the separation flowback stage may not be of salable quality. The NSPS defines ''salable quality gas'' as ''natural gas that meets the flow line or collection system operator specifications, regardless of whether such gas is sold.'' It is our intent to prohibit the direct venting of any gas during the separation flowback stage. However, because we are aware that not all recovered gas is of salable quality, the final rule requires an operator to route all salable quality recovered gas from the separator to 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. However, if, during the separation flowback stage, it is infeasible to route the recovered gas to a flow line or collection system, reinject the gas or use the gas as fuel or for other useful purpose, the recovered gas must be combusted. No direct venting of recovered gas is allowed during the separation flowback stage.

We believe these options effectively address all gas conditions (salable or non-salable) encountered during the separation flowback stage. For example, should the gas not meet minimum quality standards for entering the gathering system, we believe that would render collection ''infeasible'' until such time that the quality of the gas had improved and was acceptable. As a result, the non-salable quality gas would be combusted.

Comment: Several commenters point out that § 60.5375(a)(1)(ii) allows limited options on how liquids from the separator must be handled. According to the commenters, condensate is not always sent to a storage vessel at the well site during production, but rather is routed to a condensate or mixed well stream line and piped to another location. Sometimes the condensate is piped to a central processing facility or tank battery, and sometimes it is piped to a condensate stabilization facility where the condensate is heated and stabilized at a lower vapor pressure prior to going to a condensate tank so as to avoid flashing in the tank. One commenter states that in the Eagle Ford shale play they often elect to install blowcase units to maximize condensate recovery and to enable the direct routing of recovered liquids from the separator to a condensate collection system. This design and practice would, according to the commenter, eliminate or reduce the need for atmospheric storage vessels. According to the commenters, the proposed rule's requirement that recovered liquids must be routed to a storage vessel could be misinterpreted by regulatory agencies to not allow for companies to pipe the condensate to another location. For the separation flowback stage, paragraph § 60.5375(a)(1)(ii) should be revised to clarify that liquids may be routed to a collection system.

Response: It is the EPA's intention to allow any innovative management practice for these materials that encourages resource conservation, gas recovery and emissions reductions. We agree that routing liquids to centralized collection systems mentioned by the commenter is an innovative approach that results in reduced emissions, since the liquids are conveyed to the central facility through closed pipes, reducing emissions. The commenter mentioned production, and also cited the provisions for the separation flowback stage at § 60.5375(a)(1)(ii). We believe that collection systems should be allowed as one of the options for handling liquids during flowback and during production. In light of the comments received and our belief that centralized collection systems are protective of the environment, the final rule requires that during the separation flowback stage, all liquids from the separator must be directed to one or more well completion vessels or storage vessels, routed to a collection system or be re-injected into the well or another well. To further clarify this requirement, we have added a definition for ''collection system'' in § 60.5375 as set forth in the regulatory text of this rule.

Comment: One commenter expresses concern that allowing liquids from the separator to be routed to a well completion vessel, which as defined in the proposed rule includes lined earthen pits and as described in the proposal preamble includes open top frac tanks, may allow the release of emissions from recovered gas and other hydrocarbons. The commenter requests that the EPA clarify that the use of ''well completion vessels,'' like the use of ''storage vessels,'' during the separation flowback stage, will not result in emissions from recovered gas or other hydrocarbons.

Response: Because of the high volumes of liquids encountered during flowback, both in the initial flowback stage and in the separation flowback stage, we believe it is appropriate to route flowback liquids to a well completion vessel. Flowback consists largely of water both from the fracturing operation and water produced from the formation. In addition, such high volumes potentially could cause damage to sealed and controlled storage vessels which operate essentially at atmospheric pressure and are not designed to handle elevated pressures that could be caused by surges. Although we understand that there may be some emissions from these vessels, our intent in the well completion requirements of the NSPS is to require practices that will minimize releases to the atmosphere and maximize resource recovery, such as separation and collection of gas from the flowback unless it is technically infeasible for the separator to function and requiring gas that cannot be routed to the flow line to be combusted.

Comment: One commenter contends that limiting exceptions to the REC requirement is important, given that flaring of completion emissions represents a waste of natural resources and results in emissions of nitrogen oxides (NO_X) and carbon dioxide (CO_2) that offset the benefits of methane and VOC reduction. In this regard, the commenter is concerned that the proposed amendments continue to allow for excessive combustion of completion emissions, instead of the use of REC, when the producer deems it ''infeasible'' to capture completion emissions for sale or beneficial use.

The commenter believes that the proposed amendments would not only preserve this vague exception, but also problematically include preamble text suggesting that a producer can invoke the exception in circumstances that are contrary to the original intent of subpart OOOO. The commenter contends that in the preamble to the final rule promulgating subpart OOOO, the EPA explained its ''understanding'' that producers ordinarily ''plan their operations . . . to ensure their product has a viable path to market before completing a well,'' and that combustion in lieu of a REC would only be necessary in ''isolated cases.'' However, the preamble to the current proposed rule indicates that a REC could be deemed ''infeasible'' merely because ''there [is] no flow line or other infrastructure available at the site for collection of the gas.'' This preamble text implies that the ''infeasibility'' exception could be used for logistical reasons or for the convenience of the producer, rather than in ''isolated'' cases where inherent characteristics of the completion prevent the capture of emissions for sale or beneficial use.

Accordingly, the commenter urges the EPA to either eliminate or expressly limit the scope of the infeasibility exception in the final rule to ensure that it is consistent with the original structure and intent of subpart OOOO and is not used inappropriately. Specifically, the commenter recommends that the EPA include regulatory text clarifying that collection of completion emissions in the separation flowback stage is required unless it is technically infeasible due to inherent characteristics of the flowback or unexpected conditions, not for logistical reasons that are within the control of the operator. The commenter believes this clarification would provide operators the flexibility to use combustion instead of REC when necessary, while ensuring that combustion is an option of last resort.

Response: We agree with the commenter that the intent of the rule is to minimize completion emissions during the separation flowback stage and to maximize recovery of the gas to the flow line. The final rule requires the operator to route the recovered salable gas to 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 is infeasible to route the recovered gas to a flow line or collection system, reinject the gas or use the gas as fuel or for other useful purpose, the recovered gas must be combusted. No direct venting of recovered gas is allowed during the separation flowback stage.

While we understand the commenters concern about using the infeasibility provision to combust recovered gas when a flow line is not available, we point out that these are gas wells drilled for the production of gas; therefore the operator will have planned to be able to produce the well commercially by having the infrastructure in place and will generally avoid completing wells when it is known that the infrastructure to collect the gas and route it to market will not yet be available. However, there will be cases, though we believe to be rare, in which the operator, for reasons not within his or her control, is unable to acquire access to a flow line in time for the well completion due to unforeseen circumstances.

Comment: Several commenters took issue with the inclusion of the production stage as part of the overall well completion operation. The commenters contend that inclusion confuses or contradicts other provisions that explicitly are applicable to well completion operations and not to a well in production. The commenter believes it is critical that the rule identify when the flowback period ends and clarify that the requirements for well completions do not extend beyond the end of the flowback period.

For the commenter, the problems arise in the provisions of § 60.5375(a)(1)(iii) and in the definition of ''production stage.'' Paragraph 60.5375(a)(1)(iii) specifies requirements for the production stage, yet this paragraph is a subparagraph of § 60.5375(a), which is expressly applicable to well completion operations. Further, the commenter states that, in the proposed rule, while the beginning of the production stage marks the end of well completion operations, § 60.5365(e) indicates that the beginning of the production stage also marks the commencement of the period for determining storage vessel applicability. The commenter believes that there should be no requirements applicable to production following the end of flowback in this paragraph. One of the commenters believes that the EPA's intent of including the production stage is to ensure a storage vessel emissions evaluation occurs immediately upon the start of production. However, the commenter points out that storage vessel requirements in § 60.5365(e) already dictate that an emissions evaluation must begin at startup. Any such requirements for storage vessels should be specified in applicable portions of § 60.5365 and § 60.5395.

The commenter believes the definition of production stage requires some editing in order to be consistent with the intent that requirements for well completion operations end when production begins. The commenters make several recommendations to the change of the terms ''production stage'', and editing of other provisions to minimize any misinterpretation of the term ''production'' in well completion operations requirements. The commenter also recommends that the last sentence of § 60.5375(a)(1)(ii) be deleted and replaced with language indicating to the effect that ''the separation flowback stage ends and production begins when flow resumes after flowback equipment is removed from the well and flowback crews are released.'' See the Response to Comments Document for a full discussion of these comments.

Response: The EPA agrees with the arguments presented by the commenter regarding confusion and opportunity for misinterpretation of well completion requirements to be applicable during production. It is not the intent that rule provisions for well completions and the flowback period be applicable to the well during production over the lifetime of the well. As such, the final amendments do not include the term ''production stage'' or its definition. All references to ''production stage'' in the proposed amendments have been removed or changed to ''startup of production'' in the final amendments. Accordingly, the well completion requirements do not carry over beyond the end of the flowback period.

Comment: One commenter notes that they have many wells that go straight to the production stage, as defined in the proposed rule. The gas is recovered to a gathering line, but the liquids (produced water) are routed to a portable frac tank and then to either additional frac tanks or a lined earthen retention pond for storage. In some cases, the commenter states that the produced water is routed to the frac tanks because state regulations do not allow produced water to be routed directly to lined earthen retention ponds. The commenter also contends that routing the produced water to the frac tank also provides for better flow measurement and better control of flow into the retention pond, as well as allowing for additional sediment deposition and recovery within the frac tank. The produced water is then reused/recycled in subsequent well completions, reducing fresh water demands.

The commenter is concerned that if the proposed rule is finalized, they would be prohibited from using frac tanks and lined earthen retention ponds (well completion vessels) to recover and reuse produced water upon entering the production stage for those wells that go directly to the production stage (for these wells, upon commencing flowback). The commenter does not believe it was the EPA's intent to adversely impact water reuse and recycling practices and requests that in the final rule, ''well completion vessel'' should be included in the standards for the production stage.

The commenter understands that the EPA may have concerns over allowing the use of well completion vessels during the production stage due to the potential for VOC emissions. However, according to the commenter in the shale gas plays where the gas composition contains either no or negligible amounts of hydrocarbons, the resultant VOC emissions would be negligible as well. The commenter suggests that the EPA consider exempting shale gas flowback liquids from being required to be routed to a storage vessel on the basis of hydrocarbon gas composition and negligible VOC emissions.

Response: As stated previously, the final amendments do not include the term ''production stage'' or the associated well completions requirements that were in the proposed amendments. The final rule, as amended, states that flowback period ends when either the well is shut in and well completion equipment is removed from the well, or that production has started. With respect to the types of wells identified by the commenter, these wells would be subject to the same requirements as other wells. However, we disagree with the commenter that these wells enter directly into production, since apparently there is water from the flowback that is separated from the gas and routed to frac tanks. As a result, such wells may not go through the initial flowback stage but would enter the separation flowback stage. We remind the commenter that, even if there is no initial flowback stage or separation flowback stage as defined by the rule, then the requirements of § 60.5375(a)(2) through (4) still apply. It should be noted that there is nothing in the rule that prohibits the use of the types of structures which would be well completion vessels during the initial and separation flowback stage for the life of the well; however, once the well has begun production, the vessels then become ''storage vessels'' under the rule if they continue receiving liquids from the well for a period exceeding 60 days from startup of production. Accordingly, they would be subject to the same VOC PTE determination and, if PTE was at least 6 tpy, would be subject to the cover, closed vent system and control requirements.

2. Definition of Low Pressure Gas Well

In the 2012 final rule, we had included a definition of ''low pressure gas well.'' This was added as a logical outgrowth of the public comments received on the August 23, 2011 proposed rule (76 FR 52738) that asserted that due to the reservoir pressure, well depth and gathering line pressure, it was infeasible to perform an REC for some wells. We developed a definition based on well parameters taking into account fluid mechanics and other engineering principles. Development of the definition was described in detail in the Technical Support Document for the final rule which is in the docket. Following publication of the final rule, we received petitions that asserted that we had not provided the public an opportunity to comment on the definition. We proposed the definition in our July 2014 proposed amendments to provide the public an opportunity to comment. We also presented and solicited comment on an alternative definition provided by the petitioners.

Comment: Two commenters appreciate the EPA's willingness to propose for further comment the definition of ''low pressure gas well'' found at § 60.5430. The EPA noted that an alternative definition that was submitted for its consideration by industry petitioners was ''a well where the field pressure is less than 0.433 times the vertical depth of the deepest target reservoir and the flowback period will be less than 3 days in duration.'' The commenters support the alternative definition, although one of the commenters suggests that the word ''initial'' should be placed before the word ''flowback'' so that it is clear that the three-day period in the definition refers to the initial flowback period, and does not include the separation flowback. This commenter adds that this definition is one that is consistent with the manner in which low pressure wells are generally described in the Appalachian Basin, is easier to use and is not as susceptible to misunderstanding.

Response: In the proposed rule we solicited comment on the alternative definition suggested by the petitioners and on specific concerns or questions we have with respect to the alternative definition. We received no comments that provided any data or other information that would lead us to conclude that the alternative definition is sufficient to predict whether an REC would be infeasible for wells meeting the alternative definition.

As explained in the proposal, 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 definition in the rule 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. For these reasons, we are finalizing the definition of ''low pressure gas well'' as proposed.

Comment: A commenter concurs with the industry's alternate definition presented in the previous comment. The commenter explains that typical gas wells in Kentucky are produced from low pressure reservoirs with low permeability. In order to make them economically productive, they are stimulated with treatments that contain very little fluid. According to the commenter, all Devonian Shale wells—the largest producing reservoir in eastern Kentucky—are currently treated using straight nitrogen. Most nitrogen flowbacks require a minimum of 3 days before there is a sufficient volume of natural gas to route and flare with a combustion device. Fluid treatments or ''foamed'' fluid are almost certain to damage the formation's permeability, negating the opportunity for Kentucky's producers to continue developing that region's significant resources.

The commenter states that the current EPA definition of a ''low pressure well'' is based upon the physical characteristics of a reservoir, which is then compared to the poorly defined ''flow line pressure at the sales meter.'' Typical gathering systems in eastern Kentucky are low pressure—typically below 100 psi with the overwhelming majority below 50 psi. This makes qualifying as a ''low pressure well'' under the current definition almost impossible in Kentucky.

According to the commenter, if a Devonian Shale well cannot be qualified as ''low pressure'' after January 1, 2015, Kentucky operators will be denied the option of stimulating gas wells with an ''inert'' gas such as nitrogen. Without the ''low pressure'' qualification, the requirement of a green completion eliminates the ability to flow the wells back to the atmosphere to remove the nitrogen used in the stimulation. The commenter predicts that drilling in Kentucky's Appalachian region will cease unless the EPA adopts the proposed alternative ''low pressure well'' definition.

Response: We believe the commenter may be misinterpreting the proposed rule. The commenter appears to interpret the rule language as requiring liquids to be used for stimulating the well. This is not the case. The owner or operator is free to use any stimulation procedure so long as the handling of the liquids and gases released from the well follows the rule's provisions.

Based on the comment, it appears that there will be essentially little or no liquids discharged from these wells during the completion process, and that the initial flowback period would consist of the period of nitrogen flowback that precedes the production of natural gas. There is nothing in the NSPS that prohibits venting of nitrogen. However, any liquids that are discharged would have to be handled as specified in the rule. The commenter does not appear to be concerned about these rule provisions.

The problem appears to be related to the rule provisions that require the operator to route the recovered gas to 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. As explained above, the final amendments clarify that during the initial flowback stage, gas may be vented. It appears that the types of completions discussed by the commenter do not have a separation flowback stage (based on the limited recovered liquids), and once the nitrogen stimulation gas is off-gassed, the well goes directly to production. If this is the case, there should not be excessive back pressure introduced by the separator and other flowback equipment that would overly impede gas flow, which was the situation the EPA was intending to avoid by providing exemptions for low pressure gas wells. As a result, as described by the commenter, we believe that such wells do not need a low pressure well exemption to enable them to be completed and to startup production. We note that, even if there is no initial flowback stage or separation flowback stage as defined by the rule, then the completion is still subject to the requirements of § 60.5375(a)(2) through (4).

If completion operations on these wells do in fact involve a separation flowback stage, then § 60.5375(a)(1)(ii) would apply, meaning that during the separation flowback stage, all salable gas must be routed to the flow line and that, if it is infeasible to route the recovered gas to a flow line or collection system, reinject the gas or use the gas as fuel or for other useful purpose, the recovered gas must be combusted. No direct venting of recovered gas is allowed during the separation flowback stage.

In the case of the Devonian shale wells, we understand that the initial gas flow is predominantly nitrogen which is not combustible. However, based on the initial flowback provisions under the final rule, these gases would be allowed to be vented during initial flowback. It is assumed that as the nitrogen stimulant gas is released from the well, the hydrocarbon proportion of recovered gas will continually increase and eventually become combustible. Therefore, based on the above rationale, we do not agree that these wells should be specifically exempted as low pressure wells.

B. Storage Vessels

Comment: One commenter believes the proposed definition of ''removed from service'' is too narrow. The commenter suggests that a storage vessel affected facility should be considered removed from service if it no longer meets the definition of a storage vessel, regardless of whether it is physically isolated and disconnected from the process. As proposed, the commenter contends that the rule addresses only a single scenario when a storage vessel is no longer used to store any materials. However, there are many other scenarios where a storage vessel affected facility may still be used for storage but no longer meets the definition of storage vessel and would thus no longer be subject to the rule requirements. Examples of such scenarios provided by the commenter include an atmospheric condensate tank converted to methanol storage or non-VOC storage which may need to be connected to the process; a bullet tank previously operated as an atmospheric condensate tank for which its service is subsequently changed to pressurized storage of butane and is connected to the process; and a bullet tank previously operated as an atmospheric produced water tank and which its service is subsequently changed to a surge control process vessel and is connected to the process.

For the scenario where a storage vessel is no longer used to store anything, the commenter contends that the language regarding physical isolation and disconnection is not necessary because the definition of storage vessel states, ''vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water . . .'' Thus, if those materials were to again enter the storage vessel, the vessel would be ''returned to service'' and subject to the applicable requirements. The commenter points out that in the unique scenario where a storage vessel is no longer used to store anything, physical isolation is sufficient; disconnection should not be required if, for example, blind flanges are installed. The commenter suggests several changes to the definition of removed from service to cover all scenarios where a storage vessel may no longer meet the definition of storage vessel for purposes of subpart OOOO, but is still used for storage of liquids not included in the definition of ''storage vessel.''

Another commenters recommends that the EPA separate the definition of returned to service from the definition of removed from service and provided suggested language.

Response: We agree that the proposed definition of ''removed from service'' did not sufficiently address the many scenarios identified by the commenters. In particular, the scenario where a storage vessel affected facility is removed from service for a period of time and then returned to service for some purpose was not clearly addressed under the proposed rule. As discussed further in section IV.B of this preamble, we have revised the definition of ''removed from service'' and added a definition for ''returned to service.''

Comment: Several commenters do not support the concept of a storage vessel maintaining its subpart OOOO applicability status when that storage vessel is relocated to a different well site. One commenter stated that storage vessel PTE at a previous location is irrelevant to the new location and is entirely dependent on the particular type of service for which the vessel is being used at the new location. The commenters point out that the emissions from storage vessels are not related to the equipment itself, but rather the characteristics and volume of the fluids being sent to and stored in the storage vessel.

As proposed, the commenters believe that the rule could require an operator to control a storage vessel with little actual emissions and could discourage the replacement of older damaged storage vessels with newer vessels that may have come from a location that had emissions above the 6 tpy threshold. One commenter concurred that applicability should be based on the type of liquids introduced into the relocated storage vessel and the emissions, not just the type of liquids. The commenters seek confirmation that applicability of storage vessels is triggered by the addition of crude oil, condensate, produced water or intermediate hydrocarbon liquids to the vessel and the unique production of the new location, rather than by simply moving the vessel to a new location.

The commenters believe the proposed rule requirements are further complicated if the out-of-service storage vessel is sold to another owner or operator as part of the relocation. ''Tank pedigree'' tracking would quickly become unduly burdensome. The commenter agrees that if the vessel's emissions are above 6 tpy at the new location, it should be fully subject to the rule. The commenters believe that the tracking and recordkeeping burden of having to assess different emissions thresholds on different affected facility storage vessels based solely on their movement within the company is an excessive and unrealistic burden, particularly where the storage vessel emissions are less than 6 tpy at the new location. At this point, according to the commenters, the tank is no longer a storage vessel affected facility and should not be subject to the rule's requirements, including annual reporting, regardless of whether the storage vessel's previous owner/operator used the vessel in a service at a different location and facility, which resulted in emissions sufficient to trigger rule applicability. Unless the storage vessel's emissions are above 6 tpy at the new location, the commenters contend that subpart OOOO requirements should not be imposed on a relocated storage vessel.

One commenter requests that controls only be required when that relocated tank's emissions exceed 6 tpy, and not merely 4 tpy as required in § 60.5395(f)(2)(ii)(B). The commenter does not understand why the initial emissions assessment should be different for a relocated storage vessel compared to a newly constructed storage vessel. The commenter states that the hydrocarbon composition flowing through the relocated storage vessel may be significantly different at the new location, and the owner or operator of the storage vessel should not be penalized with a lower emissions threshold. The commenter points out that a storage vessel affected facility is defined as ''a single storage vessel . . . that has the potential for VOC emissions equal to or greater than 6 tpy . . . [taking] into account requirements under a legally and practically enforceable limit . . .'' The commenter contends that by requiring a 4 tpy threshold for relocated affected facility storage vessels, the EPA is effectively requiring control devices on storage vessels that have emissions below the threshold that is cost effective to control. Therefore, the commenter contends that a 4 tpy threshold for relocated affected facility storage vessels is legally unsupportable.

Finally, another commenter seeks clarification on the requirements for storage vessels that are returned to service at the same location. In the September 23, 2013 final rule amendments, the EPA added requirements at § 60.5395(f)(2)(ii)(B), which states that ''[i]f the uncontrolled VOC emissions without considering control from your storage vessel affected facility are 4 tpy or greater, you must comply with paragraph (d) of this section within 60 days of returning to service.'' However, the commenter points out that storage vessel affected facilities returned to service with uncontrolled emissions less than 4 tpy are not addressed and the commenter seeks clarification of this issue.

Response: We agree with the commenters' assertion that the emissions from a storage vessel are not intrinsic to the vessel but are a result of the operation and service to which the storage vessel is connected. We have provided a detailed discussion of this issue and the final amendments for storage vessels that are removed from service and returned from service in section IV.B.

Comment: Several commenters expressed general support for allowing the use of electronic spark ignition systems on combustion control devices, although many of the commenters also suggested modifications to the proposed requirements.

One commenter notes that Colorado's Regulation Number 7 requires all combustion devices used to control hydrocarbon emissions utilize an auto-igniter to ensure the operation of the continuous flame pilot. During the adoption of this requirement, the Colorado Air Quality Control Commission determined that auto-igniters were a cost-effective method to reduce hydrocarbon emissions. Another commenter notes that the Fort Berthold Indian Reservation Federal Implementation Plan allows for the use of continuous pilots or automatic spark igniters.

Three commenters note that in the Natural Gas STAR program, the EPA published a Partner Recognized Opportunity (PRO) in PRO Fact Sheet No. 903 that discusses the operation and benefits of electronic spark ignition systems. The commenter contends that the EPA should not lose the benefits of this control technology enhancement by disallowing its use in this rule. With this being an established technology in Natural Gas STAR, the commenters do not believe operators should have to petition the EPA for approval under its new control technology provision. The commenters request that the rule be modified to explicitly allow the use of electronic spark ignition systems as an alternative to a continuous pilot flame.

The commenters add that in the arctic environment in Alaska, operators have often encountered situations where, following maintenance on a flare, a new spark igniter with frost buildup cannot re-light the flare pilot. Continuous pilot flames are required for safety and certainty of combustion in arctic Alaska. Therefore, the commenters contend that if an electronic spark ignition system is allowed, it needs to be an option, rather than a requirement. Two other commenters agree that it should only be an option.

One commenter believes that spark ignition systems may be most appropriate for flares which only occasionally operate (such as flares to handle mishap/safety shutdowns, maintenance blowdowns, etc.) and flares that operate more or less continuously, such as a flare for a wet seal compressor seal-degassing unit. In both cases they may be more reliable than a pilot light, since spark ignition systems cannot be blown out and do not consume fuel and increase emissions, as a pilot light does. However, the commenter contends that a spark ignition system should not be the sole ignition mechanism for flares with highly variable flow, such as flares associated with well completion flowback or storage tank control systems. The commenter states that variable flow can lead to sputtering flames, and a failure to burn all the gas directed to the flare, leading to large emissions of VOC and methane from the flare. The commenter is concerned that a spark ignition device may not restart the flare as rapidly as a pilot light in such situations, which could lead to higher emissions for flares on variable flow sources such as wells and storage tanks. Given the high rate of emissions of VOC and methane during flowback flaring, it would be appropriate to require both pilot lights and spark ignition devices.

One commenter adds that although they believe electronic spark ignition systems should be allowed as an option, the EPA has not provided any evidence or data to suggest that pilots do not remain continuously lit during operation in the applications used for compliance with this rule. Nor has the EPA provided any data on potential environmental benefit of such technology. The commenter also contends that safety implications must be seriously considered when using auto-igniters. When use is appropriate, operators must be able to tailor the auto-igniter configuration and operation to the combustion device, the facility design, the flammability of the waste stream, facility operations and applicable industry standards. The commenter states that the EPA should not attempt to create a blanket mandate for the application or operation of auto-igniters since safety risks must be evaluated, often on a case-by-case basis. Auto-igniters may not be appropriate or allowed in current industry standards for all applications (such as heaters, boilers, and enclosed combustors). The commenter provides details of safety concerns related to electronic spark ignition systems in their comments.

Two commenters recommend that electronic spark ignition systems have fail safe systems such as temperature and pressure monitoring to prevent any venting during periods when vapors are flowing to the device.

One commenter points out that electronic spark ignition systems have been available for over twenty years and have a proven track record of successfully and safely lighting and maintaining flares and fuel burning equipment.

Response: In our response to comments on the 2011 proposed rule, we stated that given the intermittent and inconsistent nature of emissions from storage vessels in this industry combined with the highly variable VOC concentration in the emissions, we did not believe at that time that a spark-ignited flare would achieve the same level of emission reduction as a flare with a continuous flame present.

In the July 17, 2014, proposed rule, we solicited 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 were interested in information on the use of this technology as a means of ensuring that continuous flame pilots remain functional at all times. Therefore, we also solicited 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.

Although we received some information, we received no data in response to most of the questions we asked that would help us determine that electronic spark ignition should be allowed as an alternative to a continuous pilot flame.

Accordingly, issues and concerns related to intermittent and inconsistent flow still remain. Specifically, we remain concerned with how quickly an electronic spark ignition system will ignite an emission stream from an intermittent and inconsistent emission source. We also remain to have concerns about flame stability.

In light of the comments received and the lack of information received in response to our solicitation, we are not satisfied at this time that we have sufficient information on which to base a decision to allow electronic spark ignition as an alternative to a continuous pilot flame.

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

Comment: One commenter expressed support for the EPA's proposal to allow reciprocating compressor rod packing emissions to be routed to a process. However, the commenter claims that they cannot comply with the structure of the requirements as proposed. Also, the commenter contends that the proposed requirements do not conform to the current structure of the rule. The commenter recommends several changes:

First, the commenter states that proposed § 60.5385(a)(3) references initial compliance requirements with § 60.5411(a) and (b), which is unnecessary and inconsistent with § 60.5385(a)(1) and (2). The commenter also believes it is inconsistent with the rule's structure for other affected facilities.

Second, the commenter states that the EPA is not proposing to modify § 60.5410(c)(1) (initial compliance requirements) which states ''[d]uring the initial compliance period, you must continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement.'' The commenter contends that reciprocating compressor affected facilities complying with § 60.5385(a)(3) cannot comply with this requirement. Thus, the commenter believes that this requirement must be revised. Additionally, the commenter contends that there is not an initial compliance requirement here for compressors complying with § 60.5385(a)(3); thus, it would be inappropriate to reference the § 60.5411(a) and (b) requirements.

Third, the commenter states that in the proposed continuous compliance requirements in § 60.5415(c)(4), the EPA proposes to reference the initial compliance requirements in § 60.5411(a) and (b). The commenter contends that this does not make sense and does not conform to the changes that the EPA is also proposing at § 60.5416(a) and (b) (continuous cover and closed vent system requirements).

Fourth, the commenter states that the EPA is proposing to make § 60.5416(a) and (b) (continuous cover and closed vent system requirements) applicable for reciprocating compressors; however, the recordkeeping requirements associated with § 60.5416(a) and (b) have not been modified to conform to this proposed change. Additionally, the commenter believes § 60.5420(c)(6) currently fails to reference § 60.5416(a)(2). The commenter recommends that the EPA take this opportunity to resolve this oversight.

One commenter does not believe that the proposed application of the closed vent system requirements to reciprocating compressors or the routing of the rod packing equipment through a closed vent system to a process in § 60.5385(a)(3) are appropriate alternatives.

Response: The EPA disagrees with several aspects of the comments but also agrees with certain suggestions. The commenter states that the reference in § 60.5385(a)(3) to § 60.5411(a) and (b) is not necessary. The EPA disagrees with this comment, because we consider it necessary to specify the standards to which a closed vent system and cover must be designed and operated to achieve the emission reductions sought by the rule.

The EPA disagrees with the comment that the reference to § 60.5411(a) and (b) make it inconsistent with § 60.5385(a)(1) and (2). Neither § 60.5385(a)(1) nor (2) relies on additional equipment (*e.g.,* covers and closed vent systems) to be operated properly to obtain the required emission reductions. Therefore, no such reference is needed in § 60.5385(a)(1) or (2).

The EPA agrees that compliance with 60.5410(c)(1) is intended for owners and operators that have not exercised their option to comply with 60.5385(a)(3), and has finalized language to that effect suggested by the commenter. The EPA has added a restrictive clause to § 60.5410(c) such that § 60.5410(c)(1) through (4) apply only to sources electing to comply with § 60.5385(a)(1) and (2). We made this change because several of the provisions of § 60.5410(c)(1) through (4) are inappropriate for affected facilities that have chosen to comply with § 60.5385(a)(3) rather than (a)(1) and (2).

The EPA agrees that owners and operators that route rod packing emissions to a process under § 60.5385(a)(3) are not subject to § 60.5410(c)(1). We have amended § 60.5410(c) to specify that owners and operators using closed vent systems and covers are not subject to § 60.5410(c)(1).

The commenter states that requirements in § 60.5411(a) and (b) are initial compliance requirements and should not be referenced in the continuous compliance requirements of § 60.5415(c)(4). The EPA disagrees with the commenter because there are requirements within § 60.5411(a) and (b) that require compliance beyond initial compliance. Therefore, we believe it is necessary to specify continuous compliance with § 60.5411(a) and (b).

The commenter states that § 60.5416(a) and (b) should be qualified so as to apply only the reciprocating compressors subject to § 60.5385(a)(3). The EPA agrees with this comment and has added language to make this change.

The EPA agrees that § 60.5415(c)(4) is intended to describe the requirements applicable to reciprocating compressors operating under § 60.5385(a)(3) and should refer to the continuous compliance requirements applicable to closed vent systems and covers specified in § 60.5416(a) and (b).

The EPA agrees with the suggested revision of 60.5420(c) (6) through (9), and has made the changes to the regulatory text.

Comment: One commenter also expressed support for the proposed changes to § 60.5385 to allow the emissions from reciprocating compressors to be routed to a process, but believes other revisions, similar to or the same as those suggested by the previous commenter, are needed in the rule to maintain consistency with the proposed changes. The commenter's suggestions are not repeated here but are detailed in their comments.

Response: As discussed in the response to a previous comment, the EPA has made several amendments to the proposed rule language to clarify the requirements for reciprocating compressors.

VI. Technical Corrections and Clarifications

The EPA is finalizing corrections and clarifications to the 2012 NSPS and the 2013 storage vessel amendments including typographical and grammatical errors, as well as incorrect dates and cross-references. Details of the specific changes we are finalizing to the regulatory text may be found in the docket for this action.[4]

VII. Impacts of These Final Amendments

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 this action as would have been necessary to meet the previously finalized standards. We project that these amendments will result in no significant change in costs, emission reductions, or benefits. Even if there were changes in costs for the affected facilities, such changes would likely be small relative to both the overall costs of the individual projects and the overall costs and benefits of the final rule. Since we believe that owners and operators would put on the same controls for this revised final rule that they would have for the original final rule, there should not be any incremental costs related to this final revision.

[4] Memorandum from Moore, Bruce, U.S. EPA, to Docket ID 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 finalized in this action as they would have installed to comply with the previously finalized standards. Accordingly, we believe that this final rule will not result in significant changes in emissions of any of the regulated pollutants.

B. What are the energy impacts?

This final 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 final rule because 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 finalized in this action as they would have chosen to comply with the previously finalized standards, we do not anticipate that this final 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 final 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 action and we do not anticipate any significant emission changes resulting from these amendments to the rule. Therefore, there are no direct monetized benefits or disbenefits associated with this final rule.

VIII. Statutory and Executive Order Reviews

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

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

This action is not a significant regulatory action and was therefore not submitted to the Office of Management and Budget (OMB) for review.

B. Paperwork Reduction Act (PRA)

This action does not impose any new information collection burden under the PRA. OMB has previously approved the information collection activities contained in the existing regulations and has assigned OMB control number 2060–0673. Today's action does not change the information collection requirements previously finalized and, as a result, does not impose any additional information collection burden on industry.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. In making this determination, the impact of concern is any significant adverse economic impact on small entities. 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, has no net burden or otherwise has a positive economic effect on 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 today's action imposes no additional compliance costs on owners or operators of affected sources. We have therefore concluded that this action will have no net regulatory burden for all directly regulated small entities.

D. Unfunded Mandates Reform Act of 1995 (UMRA)

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This action imposes no enforceable duty on any state, local or tribal governments or the private sector.

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.

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

This action does not have tribal implications as specified in Executive Order 13175. 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.

Although at proposal the EPA noted that Executive Order 13175 did not apply, the EPA solicited comment from tribes inclined to comment on the proposed action. The EPA did not receive substantive comments from tribes on our proposal.

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

This action is not subject to Executive Order 13045 because it is not economically significant as defined in Executive Order 12866, and because the EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children.

This action does not add to or relieve affected sources from any requirements, and therefore has no impacts; thus, health and risk assessments were not conducted. The public was 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. The EPA received no substantive information on these risks.

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

This action is not subject to Executive Order 13211 because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

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

The EPA believes the human health or environmental risk addressed by this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations because it does not affect the level of protection provided to human health or the environment. The basis for this determination is that this action is a reconsideration of existing requirements and imposes no new impacts or costs.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 60

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

Dated: December 19, 2014.

Gina McCarthy,

Administrator.

For the reasons set out in the preamble, title 40, chapter I of the Code of Federal Regulations is amended as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

Subpart OOOO—[Amended]

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

§ 60.5365 Am I subject to this subpart?

* * * * *

(e) Each storage vessel affected facility, which is a single storage vessel located in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment, and has the potential for VOC emissions equal to or greater than 6 tpy 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 provided in paragraphs (e)(1) through (4) of this section. The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in this 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.

(1) For each new, modified or reconstructed storage vessel 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 startup of production.

(2) A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than 6 tpy shall remain an affected facility under this subpart.

(3) For storage vessels not subject to a legally and practically enforceable limit in an operating permit or other requirement established under Federal, state, local or tribal authority, any vapor from the storage vessel that is recovered and routed to a process through a VRU designed and operated as specified in this section is not required to be included in the determination of VOC potential to emit for purposes of determining affected facility status, provided you comply with the requirements in paragraphs (e)(3)(i) through (iv) of this section.

(i) You meet the cover requirements specified in § 60.5411(b).

(ii) You meet the closed vent system requirements specified in § 60.5411(c).

(iii) You maintain records that document compliance with paragraphs (e)(3)(i) and (ii) of this section.

(iv) In the event of removal of apparatus that recovers and routes vapor to a process, or operation that is inconsistent with the conditions specified in paragraphs (e)(3)(i) and (ii) of this section, you must determine the storage vessel's potential for VOC emissions according to this section within 30 days of such removal or operation.

(4) For each new, reconstructed, or modified storage vessel with startup, startup of production, or which is returned to service, affected facility status is determined as follows: If a storage vessel is reconnected to the original source of liquids; used to replace any storage vessel affected facility; or is installed in parallel with any storage vessel affected facility, it is a storage vessel affected facility subject to the same requirements as before being removed from service, or applicable to the storage vessel affected facility being replaced, or with which it is installed in parallel immediately upon startup, startup of production, or return to service.

* * * * *

■ 3. Section 60.5375 is amended by:

■ a. Revising paragraphs (a) introductory text and (a)(1) through (3);

■ b. Revising paragraph (b);

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

■ d. Revising paragraph (f)(2).

The revisions read as follows:

§ 60.5375 What standards apply to gas well affected facilities?

* * * * *

(a) Except as provided in paragraph (f) of this section, for each well completion operation with hydraulic fracturing begun prior to January 1, 2015, you must comply with the requirements of paragraphs (a)(3) and (4) of this section unless a more stringent state or local emission control requirement is applicable; optionally, you may comply with the requirements of paragraphs (a)(1) through (4) of this section. For each new well completion operation with hydraulic fracturing begun on or after January 1, 2015, you must comply with the requirements in paragraphs (a)(1) through (4) of this section. You must maintain a log as specified in paragraph (b).

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

(i) During the initial flowback stage, route the flowback into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the initial flowback stage is not subject to control under this section.

(ii) During the separation flowback stage, route all recovered liquids from the separator to one or more well completion vessels or storage vessels, re-inject the liquids into the well or another well or route the recovered liquids to a collection system. Route the recovered gas from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an 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, it is not technically feasible for a separator to function, you must comply with (a)(1)(i) of this section.

(2) All salable quality recovered gas must be routed to the gas flow line as soon as practicable. In cases where salable quality 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 well completion operation 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 unless it is technically infeasible for a separator to function. Any gas present in the flowback before the separator can function is not subject to control under this section. 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. 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) of this section.

* * * * *

(3) Collect the emissions from the rod packing using a rod packing emissions collection system which operates under negative pressure and route the rod packing emissions to a process through a closed vent system that meets the requirements of § 60.5411(a).

* * * * *

■ 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).

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 paragraph (f) of this section. For storage vessel affected facilities 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 startup of production as defined in § 60.5430.

* * * * *

(f) *Requirements for Group 1 and Group 2 storage vessel affected facilities that are removed from service or returned to service.* If you remove a Group 1 or Group 2 storage vessel affected facility from service, you must comply with paragraphs (f)(1) through (3) of this section. A Group 1 or Group 2 storage vessel is not an affected facility under this subpart for the period that it is removed from service.

(1) For a storage vessel affected facility to be removed from service, you must comply with the requirements of paragraph (f)(1)(i) and (ii) of this section.

(i) You must completely empty and degas the storage vessel, such that the storage vessel no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(ii) You must submit a notification as required in § 60.5420(b)(6)(vi) in your next annual report, identifying each storage vessel affected facility removed from service during the reporting period and the date of its removal from service.

(2) If a storage vessel identified in paragraph (f)(1)(ii) of this section is returned to service, you must determine its affected facility status as provided in § 60.5365(e).

(3) For each storage vessel affected facility returned to service during the reporting period, you must submit a notification in your next annual report as required in § 60.5420(b)(6)(vii), identifying each storage vessel affected facility and the date of its return to 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), 60.482–7a(a), 60.482–11a(a), and paragraph (b)(1) of this section.

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of §§ 60.482–2a(a)(1), 60.482–7a(a), 60.482–11a(a), and paragraph (b)(1) of this section.

* * * * *

■ 8. Section 60.5410 is amended by:
■ a. Revising paragraph (c)(1);
■ b. Adding a new paragraph (c)(2); and
■ c. 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?

* * * * *

(c) * * *

(1) If complying with § 60.5385(a)(1) or (2), during the initial compliance period, you must continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement.

(2) If complying with § 60.5385(a)(3), you must operate the rod packing emissions collection system under negative pressure and route emissions to a process through a closed vent system that meets the requirements of § 60.5411(a).

* * * * *

(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 and introductory text;
■ b. Revising the heading of paragraph (a);
■ c. Revising paragraph (a)(1);
■ d. Revising paragraph (b)(3); and
■ e. Revising the heading of paragraph (c).

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?

You must meet the applicable requirements of this section for each cover and closed vent system used to comply with the emission standards for your storage vessel, reciprocating compressor or centrifugal compressor affected facility.

(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 rod packing emissions collection system 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) * * *

(3) Each storage vessel thief hatch shall be equipped, maintained and operated with a weighted mechanism or equivalent, to ensure that the lid remains properly seated. 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 the introductory text of paragraph (e); and
■ b. Adding paragraph (e)(7).

The revision and addition read as follows:

§ 60.5413 What are the performance testing procedures for control devices used to demonstrate compliance at my storage vessel or centrifugal compressor affected facility?

* * * * *

(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 (b)(2) introductory text;
■ b. Revising paragraph (c) introductory text;
■ c. Adding paragraph (c)(4); and
■ d. Removing paragraph (h).

The revisions and addition read as follows:

§ 60.5415 How do I demonstrate continuous compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?

(b) * * *

(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) of this section.

* * * * *

(4) You must operate the rod packing emissions collection system under negative pressure and continuously comply with the closed vent requirements in § 60.5411(a).

* * * * *

■ 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 compressor affected facility as specified in paragraphs (a)(1), (2), or (3) of this section, you must meet the requirements of paragraphs (b)(1) through (13) of this section.

* * * * *

■ 14. Section 60.5420 is amended by:
■ a. Revising paragraph (b)(1)(iv);
■ b. Revising paragraph (b)(6)(ii);
■ c. Revising paragraphs (b)(6)(vi) and (vii);
■ d. Revising paragraphs (c)(1)(iii)(A) and (B);
■ e. Revising paragraph (c)(3)(ii); and
■ f. Revising paragraphs (c)(7), (8) and (9).

The revisions read as follows:

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

* * * * *

(b) * * *

(1) * * *

(iv) A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

* * * * *

(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 or is returned to service 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)(ii), including the date the storage vessel affected facility was removed from service.

(vii) You must identify each storage vessel affected facility returned to service during the reporting period as specified in § 60.5395(f)(3), including the date the storage vessel affected facility was returned to service.

* * * * *

(c) * * *

(1) * * *

(iii) * * *

(A) For each gas well affected facility required to comply with the requirements of § 60.5375(a), you must record: The location of the well; the API well number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time of each attempt to direct flowback to a separator as required in § 60.5375(a)(1)(i); the date and time of each occurrence of returning to the initial flowback stage under § 60.5375(a)(1)(i); and the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery to the flow line; duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours of time.

(B) For each gas well affected facility required to comply with the requirements of § 60.5375(f), you must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record the duration of recovery to the flow line.

* * * * *

(3) * * *

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

* * * * *

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

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

(9) If you are subject to the closed vent system no detectable emissions requirements of § 60.5416(b) for centrifugal or reciprocating compressors, a record of the monitoring conducted in accordance with § 60.5416(b).

* * * * *

■ 15. Section 60.5430 is amended by:

■ a. Adding, in alphabetical order, definitions for the terms ‘‘Certifying official,’’ ‘‘Collection system,’’ ‘‘Initial flowback stage,’’ ‘‘Maximum average daily throughput,’’ ‘‘Recovered gas,’’ ‘‘Recovered liquids,’’ ‘‘Removed from service,’’ ‘‘Returned to service,’’ ‘‘Separation flowback stage,’’ ‘‘Startup of production,’’ and ‘‘Well completion vessel;’’

■ b. Removing the definition of ‘‘Affirmative defense;’’ and

■ c. Revising the definitions for ‘‘Equipment’’, ‘‘Flowback,’’ ‘‘Routed to a process or route to a process,’’ ‘‘Salable quality gas,’’ and ‘‘Storage vessel.’’

The revisions read as follows:

§ 60.5430 What definitions apply to this subpart?

* * * * *

Certifying official means one of the following:

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

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including but not limited to general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

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

(4) For affected facilities:

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

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

* * * * *

Collection system means any infrastructure that conveys gas or liquids from the well site to another location for treatment, storage, processing, recycling, disposal or other handling.

* * * * *

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 well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage.

* * * * *

Initial flowback stage means the period during a well completion operation which begins at the onset of flowback and ends at the separation flowback stage.

* * * * *

Maximum average daily throughput means the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods.

* * * * *

Recovered gas means gas recovered through the separation process during flowback.

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

* * * * *

Removed from service means that a storage vessel affected facility has been physically isolated and disconnected from the process for a purpose other than maintenance in accordance with § 60.5395(f)(1).

Returned to service means that a Group 1 or Group 2 storage vessel affected facility that was *removed from service* has been:

(1) Reconnected to the original source of liquids, connected in parallel to any storage vessel affected facility or has been used to replace any storage vessel affected facility; or

(2) Installed in any location covered by this subpart and introduced with crude oil, condensate, intermediate hydrocarbon liquids or produced water.

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

Salable quality gas means natural gas that meets the flow line or collection system operator specifications, regardless of whether such gas is sold.

Separation flowback stage means the period during a well completion operation when it is technically feasible for a separator to function. The *separation flowback stage* ends either at the startup of production, or when the well is shut in and permanently disconnected from the flowback equipment.

Startup of production means the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water.

Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. Two or more storage vessels connected in parallel are considered equivalent to a single storage vessel with throughput equal to the total throughput of the storage vessels connected in parallel. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of § 60.5395(f) until such time as such tank or other vessel has been returned to service. For the purposes of this subpart, the following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by § 60.5420(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 from the date the original vessel was first located at the site. This exclusion does not apply to a well completion vessel as described above.

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

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

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Well completion vessel means a vessel that contains *flowback* during a well completion operation following hydraulic fracturing or refracturing. A well completion vessel may be a lined earthen pit, a tank or other vessel that is skid-mounted or portable. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart.

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