ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2017–0483; FRL–10013–60–OAR]

RIN 2060–AT54

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes amendments to the new source performance standards (NSPS) for the oil and natural gas sector. The Environmental Protection Agency (EPA) granted reconsideration on the fugitive emissions requirements, well site pneumatic pump standards, requirements for certification of closed vent systems (CVS) by a professional engineer (PE), and the provisions to apply for the use of an alternative means of emission limitation (AMEL). This final action includes amendments as a result of the EPA's reconsideration of the issues associated with the above mentioned four subject areas and other issues raised in the reconsideration petitions for the NSPS, as well as amendments to streamline the implementation of the rule. This action also includes technical corrections and additional clarifying language in the regulatory text and/or preamble where the EPA concludes further clarification is warranted.

DATES: This final rule is effective on November 16, 2020.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2017–0483. All documents in the docket are listed on the *https://www.regulations.gov/* website. Although listed, some information is not publicly available, *e.g.,* Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *https://www.regulations.gov.* Out of an abundance of caution for members of the public and our staff, the EPA Docket Center and Reading Room are closed to the public, with limited exceptions, to reduce the risk of transmitting COVID–19. Our Docket Center staff will continue to provide remote customer service via email, phone, and webform. For further information and updates on EPA Docket Center services, please visit us online at *https://www.epa.gov/dockets.* The EPA continues to carefully and continuously monitor information from the Center for Disease Control, local area health departments, and our Federal partners so that we can respond rapidly as conditions change regarding COVID–19.

FOR FURTHER INFORMATION CONTACT: For questions about this action, contact Ms. Karen Marsh, Sector Policies and Programs Division (E143–05), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–1065; fax number: (919) 541–0516; and email address: *marsh.karen@epa.gov.*

SUPPLEMENTARY INFORMATION:

Preamble acronyms and abbreviations. A number of acronyms and terms are used 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:

AMEL Alternative Means of Emission Limitation
ANSI American National Standards Institute
AVO Auditory, Visual, and Olfactory
boe Barrels of Oil Equivalent
BSER Best System of Emissions Reduction
CAA Clean Air Act
CAPP Canadian Association of Petroleum Producers
CEDRI Compliance and Emissions Data Reporting Interface
CFR Code of Federal Regulations
CO_2 Eq. Carbon dioxide equivalent
CPI Consumer Price Indices
CVS Closed Vent System
DOE Department of Energy
EAV Equivalent Annualized Value
EPA Environmental Protection Agency
FEAST Fugitive Emissions Abatement Simulation Toolkit
GHG Greenhouse Gases
GHGI Greenhouse Gas Inventory
HAP Hazardous Air Pollutant(s)
ITRC Interstate Technology and Regulatory Council
LDAR Leak Detection and Repair
METEC Methane Emissions Technology Evaluation Center
NEMS National Energy Modeling System
NSPS New Source Performance Standards
NSSN National Standards System Network
NTTAA National Technology Transfer and Advancement Act
OGI Optical Gas Imaging
OMB Office of Management and Budget
PE Professional Engineer
PRA Paperwork Reduction Act
PRD Pressure Relief Device
PRV Pressure Relief Valve
PTE Potential To Emit
PV Present Value
REC Reduced Emissions Completion
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
RTC Responses to Comments
SOCMI Synthetic Organic Chemicals Manufacturing Industry
The Court United States Court of Appeals for the District of Columbia Circuit
tpy Tons Per Year
TSD Technical Support Document
UIC Underground Injection Control
UMRA Unfunded Mandates Reform Act
VOC Volatile Organic Compounds

Organization of this document. The information presented in this preamble is presented as follows:

I. Executive Summary

A. Purpose of the Regulatory Action

The purpose of this action is to finalize amendments to the NSPS for the Crude Oil and Natural Gas Production source category (located at 40 Code of Federal Regulations (CFR) part 60, subpart OOOOa) based on the EPA's reconsideration of those standards. On June 3, 2016, the EPA published a final rule titled ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule,'' at 81 FR 35824 (''2016 NSPS subpart OOOOa''). The 2016 NSPS subpart OOOOa set the standards for reducing emissions of greenhouse gases (GHG), in the form of limitations on methane, and volatile organic compounds (VOC) from the oil and natural gas sources constructed, modified, or reconstructed after September 15, 2015.[1] Following promulgation of the final rule, the Administrator received petitions for reconsideration of several provisions of the 2016 NSPS subpart OOOOa.[2] The EPA granted reconsideration on four issues: (1) The applicability of the fugitive emissions requirements to low production well sites, (2) the process and criteria for requesting approval of an AMEL, (3) the well site pneumatic pump standards, and (4) the requirements for certification of CVS by a PE. On October 15, 2018, the EPA published a proposed rulemaking titled ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration,'' in which we proposed amendments to the 2016 NSPS subpart OOOOa to address the issues for which reconsideration was granted, as well as other implementation issues and technical corrections. 83 FR 52056. After considering public comments and new data submitted by the commenters, the EPA is finalizing certain amendments to the 2016 NSPS subpart OOOOa as proposed, finalizing other amendments with changes from the proposal in response to comments and new data that were received, and not finalizing some of the proposed amendments in response to comments and new data that were received.

In addition to the amendments described above, this action includes amendments to address other issues raised in the reconsideration petitions for the 2016 NSPS subpart OOOOa and to clarify and streamline implementation of the rule. These amendments relate to the following provisions: Well completions (location of a separator during flowback, screenouts, and coil tubing cleanouts), onshore natural gas processing plants (definition of capital expenditure and monitoring), storage vessels (applicability), and general clarifications (certifying official and recordkeeping and reporting). Lastly, in addition to the amendments addressing reconsideration and implementation issues, the EPA is finalizing technical corrections of inadvertent errors in the 2016 NSPS subpart OOOOa.

In addition to this action, the EPA has published a separate final rule in the **Federal Register** of Monday, September 14, 2020, that finalizes additional amendments to the 2016 NSPS subpart OOOOa which are not addressed by this action. That separate final rule, titled ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review: Final Rule'' (FRL–10013–44–OAR; FR Doc. 2020–18114) is herein referred to as the ''Review Rule.'' Specifically, the Review Rule removes sources in the transmission and storage segment from the source category by revising the definition of the Crude Oil and Natural Gas Production source category, rescinds the standards (including both the VOC and methane requirements) applicable to those sources, and rescinds the methane-specific requirements of the NSPS applicable to sources in the production and processing segments. For further information about these additional amendments, see the final rule published in the *Rules and Regulations* section of the **Federal Register** of Monday, September 14, 2020. Please refer to the Regulatory Impact Analysis (RIA) for both this action and the Review Rule to see the combined impacts of both actions.

B. Summary of the Major Provisions of This Final Rule

Provided below is a summary of each key amendment, clarification, or correction made to the 2016 NSPS subpart OOOOa that is included in this final action.

Well completions. The EPA is finalizing its proposed amendment to 40 CFR 60.5375a(a)(1)(iii) to allow the separator to be nearby during flowback, but the separator must be available and ready for use as soon as it is technically feasible for the separator to function. We are also amending 40 CFR 60.5375a(a)(1)(i) to clarify that the separator that is required during the initial flowback stage may be a production separator as long as it is designed to accommodate flowback. Finally, we are amending the definition of flowback at 40 CFR 60.5430a to exclude screenouts, coil tubing cleanouts, and plug drill outs. As explained in the preamble to the proposed rulemaking, these are functional processes that allow for flowback to begin; as such, they are not part of the flowback. 83 FR 52082.

Pneumatic pumps. The EPA is finalizing an amendment to extend the exemption from control where it is technically infeasible to route pneumatic pump emissions to a control device. The final rule extends this exemption to all pneumatic pump affected facilities at all well sites by removing the reference to greenfield sites in 40 CFR 60.5393a(b) and the greenfield site definition from 40 CFR 60.5430a. Additionally, in order to qualify for the technical infeasibility exemption, the 2016 NSPS subpart OOOOa requires certification by a qualified PE that routing a pneumatic pump to a control device or a process is technically infeasible. 40 CFR 60.5393a(b)(5). This final rule allows certification of technical infeasibility by either a qualified PE or an in-house engineer with expertise on the design and operation of the pneumatic pump.

Storage vessels. This final rule amends the applicability criteria for storage vessel affected facilities by establishing criteria for calculating potential for VOC emissions under different scenarios. Specifically, for individual storage vessels that are part of a controlled tank battery (*i.e.,* two or more storage vessels manifolded together with piping such that all vapors are shared between the headspace of the storage vessels, and where emissions are routed through a CVS to a process or a control device with a destruction efficiency of at least 95.0 percent for VOC emissions) that is subject to a

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

[2] Copies of the petitions are provided in Docket ID No. EPA–HQ–OAR–2017–0483.

legally and practicably enforceable limit, potential VOC emissions may be determined by averaging the emissions from the entire tank battery across the number of storage vessels in the battery. For a controlled tank battery described above, if the average per storage vessel VOC emissions are greater than 6 tons per year (tpy), then all storage vessels in that battery are storage vessel affected facilities. For individual storage vessels that do not meet the criteria described above, the potential VOC emissions is determined according to the proposed criteria, which the EPA is finalizing in this action; where the VOC emissions are greater than 6 tpy, the storage vessel is an affected facility.

CVS. This final rule incorporates the option for owners and operators to demonstrate that the pneumatic pump CVS is operated with no detectable emissions by (1) an annual inspection using EPA Method 21 of appendix A–7 of part 60 (''Method 21''), (2) monthly audio/visual/olfactory (AVO) monitoring, or (3) optical gas imaging (OGI) monitoring at the frequencies specified for fugitive monitoring. Additionally, this final rule incorporates the option for a storage vessel CVS to be monitored by either monthly AVO monitoring or OGI monitoring at the frequencies specified for fugitive monitoring. Finally, this final rule allows for certification of the CVS design and capacity assessment by either a qualified PE or an in-house engineer with expertise on the design and operation of the CVS.

Fugitive emissions requirements. The EPA is finalizing several amendments to the requirements for the collection of fugitive emissions components at well sites and compressor stations. The monitoring frequencies in this final rule are semiannual for well sites and compressor stations, and annual for well sites and compressor stations located on the Alaska North Slope. The final rule excludes low production well sites (where the total combined oil and natural gas production for the well site is at or below 15 barrels of oil equivalent (boe) per day) from fugitive emissions monitoring, as long as they maintain the records specified in the final rule to demonstrate that their total well site production is at or below 15 boe per day. A low production well site that subsequently produces above this threshold is required to comply with the fugitive emissions requirements.

This final rule also finalizes separate initial monitoring requirements for the Alaska North Slope compressor stations, as proposed. Compressor stations located on the Alaska North Slope that start up between September and March must conduct initial monitoring within 6 months of startup or by June 30, whichever is later; compressor stations that start up between April and August must conduct initial monitoring within 90 days of startup. This final rule revises the initial monitoring requirement for well sites and compressor stations not located on the Alaska North Slope by requiring initial monitoring within 90 days of startup. Additionally, this final rule allows fugitive monitoring to stop when all major production and processing equipment is removed from a well site such that it becomes a wellhead-only well site.

In addition to the amendments related to monitoring frequencies, the final rule (1) specifies the events that constitute modifications to an existing separate tank battery surface site (which is a ''well site'' for purposes of well site fugitive emissions requirements); (2) revises the repair requirements to specify that a first attempt at repair must be made within 30 days of identifying fugitive emissions and final repair must be made within 30 days of the first attempt at repair; (3) amends the definition of a well site to exclude third-party equipment located downstream of the custody meter assembly and Underground Injection Control (UIC) Class I non-hazardous and UIC Class II disposal wells from the fugitive emissions requirements; and (4) revises the requirements for the monitoring plan, recordkeeping, and reporting associated with the fugitive emissions requirements.

AMEL. This final rule amends the provisions for application of an AMEL for emerging technologies or for existing state fugitive emissions programs. Additionally, this final rule provides alternative fugitive emissions standards for well sites and compressor stations located in specific states.

Onshore natural gas processing plants. This final rule revises the definition of ''capital expenditure'' at 40 CFR 60.5430a by replacing the equation used to determine the percent of replacement cost, ''Y'', with one that is based on the ratio of consumer price indices (CPI). Additionally, this final rule exempts components that are in VOC service for less than 300 hours/year from monitoring. The EPA is also revising the equipment leak standards for onshore natural gas processing plants (40 CFR 60.5400a) to include the same initial compliance provision that is in the original equipment leak standards for onshore natural gas processing plants. 40 CFR part 60, subpart KKK. That provision, which is codified at 40 CFR 60.632(a), requires compliance ''as soon as practicable but no later than 180 days after initial startup.'' The EPA has not been able to find a record explaining or otherwise indicating that we intended to change this initial compliance deadline for the leak standards at onshore natural gas processing plants when NSPS subparts OOOO and OOOOa were promulgated; accordingly, in these amendments to NSPS subpart OOOOa, the EPA is adding this provision back into the leak standards for onshore natural gas processing plants in NSPS subpart OOOOa at 40 CFR 60.5400a.

Sweetening units. This final rule revises the affected facility description for the sulfur dioxide (SO_2) standards to correctly define such affected facilities as any onshore sweetening unit that processes natural gas produced from either onshore or offshore wells at 40 CFR 60.5365a(g).

C. Costs and Benefits

The EPA has projected the compliance cost reductions, emissions changes, and forgone benefits that may result from the final reconsideration. The projected cost reductions and forgone benefits are presented in detail in the RIA accompanying this final rule. The RIA focuses on the elements of the final rule—the provisions related to fugitive emissions requirements and certification by a PE—that are likely to result in quantifiable cost or emissions changes compared to a baseline that includes the 2016 NSPS subpart OOOOa requirements. We estimated the effects of this final rule for all sources that are projected to change compliance activities under this action for the analysis years 2021 through 2030. The RIA also presents the present value (PV) and equivalent annualized value (EAV) of costs, benefits, and net benefits of this action in 2016 dollars.

A summary of the key results of this final rule is presented in Table 1. Table 1 presents the PV and EAV, estimated using discount rates of 7 and 3 percent, of the changes in benefits, costs, and net benefits, as well as the change in emissions under the final rule. Here, the EPA refers to the cost reductions as the ''benefits'' of this rule and the forgone benefits as the ''costs'' of this rule in Table 1. The net benefits are the benefits (cost reductions) minus the costs (forgone benefits).

TABLE 1—COST REDUCTIONS, FORGONE BENEFITS AND FORGONE EMISSIONS REDUCTIONS OF THE FINAL RULE, 2021 THROUGH 2030

[Millions 2016$]

	7-Percent discount rate		3-Percent discount rate	
	PV	EAV	PV	EAV
Benefits (Total Cost Reductions)	$750	$100	$950	$110
Costs (Forgone Benefits)	19	2.5	71	8.1
Net Benefits [1]	730	97	880	100
Emissions	Forgone Reductions			
Methane (short tons)	450,000			
VOC (short tons)	120,000			
Hazardous Air Pollutant(s) (HAP) (short tons)	4,700			
Methane (million metric tons carbon dioxide equivalent (CO_2 Eq.))	10			

Note: Estimates are rounded to two significant digits and may not sum due to independent rounding.

This final rule is expected to result in benefits (compliance cost reductions) for affected owners and operators. The PV of these benefits (cost reductions), discounted at a 7-percent rate, is estimated to be about $750 million, with an EAV of about $100 million (Table 1). Under a 3-percent discount rate, the PV of cost reductions is $950 million, with an EAV of $110 million (Table 1).

The estimated costs (forgone benefits) include the monetized climate effects of the projected increase in methane emissions under the final rule. The PV of these climate-related costs (forgone benefits), discounted at a 7-percent rate, is estimated to be about $19 million, with an EAV of about $2.5 million (Table 1). Under a 3-percent discount rate, the PV of the climate-related costs (forgone benefits) is about $71 million, with an EAV of about $8.1 million (Table 1). The EPA also expects that there will be increases in VOC and HAP emissions under the proposal. While the EPA expects that the forgone VOC emission reductions may also degrade air quality and adversely affect health and welfare effects associated with exposure to ozone, particulate matter with a diameter of 2.5 micrometers or less ($PM_{2.5}$), and HAP, we did not quantify these effects at this time. This omission should not imply that these forgone benefits do not exist. To the extent that the EPA were to quantify these ozone and particulate matter (PM) impacts, the Agency would estimate the number and value of avoided premature deaths and illnesses using an approach detailed in the Particulate Matter National Ambient Air Quality Standards (NAAQS) and Ozone NAAQS RIA (U.S. EPA, 2012; U.S. EPA, 2015). Such an analysis would account for the distribution of air pollution-attributable risks among populations most vulnerable and susceptible to $PM_{2.5}$ and ozone exposure.

The PV of the net benefits of this rule, discounted at a 7-percent rate, is estimated to be about $730 million, with an EAV of about $97 million (Table 1). Under a 3-percent discount rate, the PV of net benefits is about $880 million, with an EAV of about $100 million (Table 1).

II. General Information

A. Does this action apply to me?

Categories and entities potentially affected by this action include:

TABLE 2—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS ACTION

Category	NAICS code [1]	Examples of regulated entities
Industry	211120	Crude Petroleum Extraction.
	211130	Natural Gas Extraction.
	221210	Natural Gas Distribution.
	486110	Pipeline Distribution of Crude Oil.
	486210	Pipeline Transportation of Natural Gas.
Federal Government		Not affected.
State/local/tribal government		Not affected.

[1] North American Industry Classification System.

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

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

This final action is available in the docket at *https://www.regulations.gov/,* Docket ID No. EPA–HQ–OAR–2017–0483. Additionally, following signature by the Administrator, the EPA will post a copy of this final action at *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry.* This website provides information on all of the EPA's actions related to control of air pollution in the oil and natural gas industry. Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the final rule and key technical documents at this same website. A redline version of the regulatory language that incorporates the final changes in this action is available in the docket for this action (Docket ID No. EPA–HQ–OAR–2017–0483).

C. What is the Agency's authority for taking this action?

This action, which finalizes amendments to the 2016 NSPS subpart OOOOa, is based on the same legal authorities that the EPA relied upon for the original promulgation of the 2016 NSPS subpart OOOOa. The EPA promulgated the 2016 NSPS subpart OOOOa pursuant to its standard-setting authority under section 111(b)(1)(B) of the Clean Air Act (CAA) and in accordance with the rulemaking procedures in section 307(d) of the CAA. Section 111(b)(1)(B) of the CAA requires the EPA to issue ''standards of performance'' for new sources in a category listed by the Administrator based on a finding that the category of stationary sources causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. In the Review Rule (published in the **Federal Register** of Monday, September 14, 2020), the EPA has interpreted CAA section 111(b)(1)(B) to require a determination that the emissions of any air pollutant not already subject to an NSPS for the source category (or evaluated in association with the listing of the source category) cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. CAA section 111(a)(1) defines ''a standard of performance'' as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirement) the Administrator determines has been adequately demonstrated.'' The standard that the EPA develops, based on the best system of emission reduction (BSER) is commonly a numerical emission limit, expressed as a performance level (*e.g.,* a rate-based standard). However, CAA section 111(h)(1) authorizes the Administrator to promulgate a work practice standard or other requirements, which reflect the best technological system of continuous emission reduction, if it is not feasible to prescribe or enforce a standard of performance. This action includes amendments to the fugitive emissions standards for well sites and compressor stations, which are work practice standards promulgated pursuant to CAA section 111(h)(1). 81 FR 35829.

The final amendments in this document result from the EPA's reconsideration of various aspects of the 2016 NSPS subpart OOOOa. Agencies have inherent authority to reconsider past decisions and to revise, replace, or repeal a decision to the extent permitted by law and supported by a reasoned explanation. *FCC* v. *Fox Televisions Stations, Inc.,* 556 U.S. 502, 515 (2009); *Motor Vehicle Mfrs. Ass'n* v. *State Farm Mutual Auto. Ins. Co.,* 463 U.S. 29, 42 (1983) (''State Farm''). ''The power to decide in the first instance carries with it the power to reconsider.'' *Trujillo* v. *Gen. Elec. Co.,* 621 F.2d 1084, 1086 (10th Cir. 1980); see also, *United Gas Improvement Co.* v. *Callery Properties, Inc.,* 382 U.S. 223, 229 (1965); *Mazaleski* v. *Treusdell,* 562 F.2d 701, 720 (D.C. Cir. 1977).

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 Stated Court of Appeals for the District of Columbia Circuit by November 16, 2020. Moreover, under section 307(b)(2) of the CAA, the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements. Section 307(d)(7)(B) of the CAA further provides that ''[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review.'' This section also provides a mechanism for the EPA to convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule.'' Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, EPA WJC, 1200 Pennsylvania Ave. NW, Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

III. Background

On June 3, 2016, the EPA published a final rule titled ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Source; Final Rule,'' at 81 FR 35824 (''2016 NSPS subpart OOOOa''). The 2016 NSPS subpart OOOOa established standards of performance for GHG and VOC emissions from new, modified, and reconstructed sources in the oil and natural gas sector. For further information on the 2016 NSPS subpart OOOOa, see 81 FR 35824 (June 3, 2016) and associated Docket ID No. EPA–HQ–OAR–2010–0505. Following promulgation of the final rule, the Administrator received petitions for reconsideration of several provisions of the 2016 NSPS subpart OOOOa. Copies of the petitions are provided in the docket for this final rule (Docket ID No. EPA–HQ–OAR–2017–0483). Several states and industry associations also sought judicial review of the rule, and that litigation is currently being held in abeyance. *American Petroleum Institute, et al.* v. *EPA,* No. 13–1108 (D.C. Cir.) (and consolidated cases).

In a letter to the petitioners dated April 18, 2017, the EPA granted reconsideration of the fugitive emissions requirements at well sites and compressor stations.[3] In a subsequent notification, the EPA granted reconsideration of two additional issues: Well site pneumatic pump standards and the requirements for certification of CVS by a PE.[4] On October 15, 2018, the EPA proposed amendments and clarifications to address the issues under reconsideration, as well as issues related to the implementation of the 2016 NSPS subpart OOOOa that have come to the EPA's attention. During this rulemaking, the EPA reviewed additional information, including information in the annual compliance reports submitted for the 2016 NSPS subpart OOOOa and on costs associated with fugitive emissions monitoring. The additional information has allowed the EPA to more accurately assess the emission reductions and costs associated with the fugitive emissions requirements of the 2016 NSPS subpart OOOOa before evaluating revisions in this rulemaking. Further, the EPA used the additional information to update the overall burden estimates for the 2016 NSPS subpart OOOOa, thus, providing a more accurate baseline on which to compare any burden reductions achieved through this final rule. Upon review of the updated cost estimates,

[3] See Docket ID Item No. EPA–HQ–OAR–2010–0505–7730.

[4] 82 FR 25730.

the EPA concludes the burden of the 2016 NSPS subpart OOOOa was underestimated, and this rulemaking provided an opportunity to reduce the burden of the rule, particularly related to the recordkeeping and reporting requirements. This action finalizes amendments that would significantly reduce the recordkeeping and reporting burden of the rule while continuing to assure compliance. This action also addresses several other implementation issues that were raised following promulgation of the 2016 NSPS subpart OOOOa. The EPA is addressing these issues at the same time to provide clarity and certainty for the public and the regulated community regarding these requirements.

IV. Summary of the Final Standards

This final rule amends certain requirements in the 2016 NSPS subpart OOOOa, as discussed in this section. These amendments are effective on November 16, 2020. Therefore, the standards in NSPS subpart OOOOa change from that date forward. Accordingly, after November 16, 2020, all affected facilities that commenced construction, reconstruction, or modification after September 18, 2015 must comply with the 2016 NSPS subpart OOOOa as amended; the previous requirements no longer apply.

A. Well Completions

The 2016 NSPS subpart OOOOa requires that the owner or operator of a well affected facility have a separator on site during the entire flowback period. 40 CFR 60.5375a(a)(1)(iii). The EPA proposed and received supportive comments on allowing the separator to be located in close enough proximity to the well site for use as soon as sufficient flowback is present for the separator to function. Consistent with the proposal, this final rule amends 40 CFR 60.5375a(a)(1)(iii) to allow the separator to be at a nearby centralized facility or well pad that services the well affected facility during flowback as long as the separator can be utilized as soon as it is technically feasible for the separator to function. The EPA is also amending 40 CFR 60.5375a(a)(1)(i) to clarify that the separator that is required during the initial flowback stage may be a production separator as long as it is also designed to accommodate flowback.

The October 15, 2018, proposal also included proposed amendments to the definition of flowback. The 2016 NSPS subpart OOOOa, 40 CFR 60.5430a defines flowback as the process of allowing fluids and entrained solids to flow from a well following a treatment, either in preparation for a subsequent phase of treatment of in preparation for cleanup and returning the well to production. The term flowback also means the fluids and entrained solids that emerge from a well during the flowback process. The flowback period begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage.

In the October 15, 2018, proposed rulemaking, the EPA explained that screenouts, coil tubing cleanouts, and plug drill outs are functional processes that allow for flowback to begin; as such, they are not part of the flowback. 83 FR 52082. The proposed rulemaking included definitions for screenouts, coil tubing cleanouts, and plug drill outs, as proposed. Specifically, a screenout is an attempt to clear proppant from the wellbore in order to dislodge the proppant out of the well. A coil tubing cleanout is a process where an operator runs a string of coil tubing to the packed proppant within a well and jets the well to dislodge the proppant and provide sufficient lift energy to flow it to the surface. A plug drill-out is the removal of a plug (or plugs) that was used to isolate different sections of the well. The EPA proposed to exclude screenouts, coil tubing cleanouts, and plug drill outs from the definition of flowback. This final rule amends the definition of flowback and finalizes the definitions for screenouts, coil tubing cleanouts, and plug drill outs, as proposed.

This final rule does not include a definition for a permanent separator. The EPA proposed such a definition in conjunction with our proposal to streamline reporting and recordkeeping requirements for flowback routed through production separators (which we referred to as ''permanent separators'' in the proposed rulemaking). As explained in the preamble to the proposed rulemaking, when a production separator is used for both well completions and production, the production separator is connected at the onset of the flowback and stays on after flowback and at the startup of production; in that event, certain reporting and recordkeeping requirements associated with well completions (*e.g.,* information about when a separator is hooked up or disconnected during flowback) would be unnecessary. 83 FR 52082. We, therefore, proposed to remove such unnecessary data reporting and recordkeeping requirements when a ''permanent separator'' (as defined in the proposed rulemaking) is used for flowback. Upon further review, we learned that the term ''permanent separator,'' as defined in our proposed rulemaking, does not accurately describe production separators that are also used during flowback because such production separators may not be permanent fixtures of a site. Therefore, while the final rule streamlines reporting and recordkeeping requirements for flowback routed through production separators, on the condition that those separators are designed to accommodate flowback, it does not include the term ''permanent separator'' or the proposed definition. The details of these streamlined elements are provided in section IV.I.1 of this preamble.

B. Pneumatic Pumps

Under the 2016 NSPS subpart OOOOa, a pneumatic pump located at a non-greenfield site is not required to reduce its emissions by 95 percent if it is technically infeasible to route the pneumatic pump to a control device or process. This final rule expands the technical infeasibility exemption to pneumatic pumps at all well sites by removing the reference to greenfield site in 40 CFR 60.5393a(b) and the associated definition of greenfield site at 40 CFR 60.5430a. For the 2016 NSPS subpart OOOOa, the EPA concluded that circumstances that could otherwise make control of a pneumatic pump technically infeasible at an existing location could be addressed in the design and construction of a new site. In the proposal, the EPA explained petitioners' concerns that, even at greenfield sites, certain scenarios present circumstances where the control of a pneumatic pump may be technically infeasible despite the site being newly designed and constructed. 83 FR 52061. We, therefore, proposed to expand the technical infeasibility provision to apply to pneumatic pumps at all well sites and solicited comments on scenarios where routing a pump to a control device or process would be technically infeasible at greenfield sites. The EPA received numerous comments in support of the proposal. After consideration of the comments and further review of the standards, this action finalizes the proposed exemption from control if it is technically infeasible to route emissions from a pneumatic pump to a control device at all well sites, including greenfield sites. In addition to the reasons specified in the proposal, the EPA has reevaluated the 2016 NSPS subpart OOOOa standards for pneumatic pumps, and it is clear that the EPA did not intend to require the installation of a control device for the sole purpose of controlling emissions from a pneumatic pump, even at greenfield sites. Furthermore, in the 2016 NSPS subpart OOOOa, the assessment of technical infeasibility for a pneumatic pump is conducted within the context of an existing control device, not a control device that might be installed to also accommodate the pneumatic pump emissions. Therefore, the EPA concludes that when determining technical feasibility at any site, the technical feasibility is determined for the routing of pneumatic pump emissions to the controls which are needed for the processes at the site. Moreover, while it is likely uncommon that an owner or operator cannot design a greenfield site with a control device to reduce pneumatic pump emissions (*e.g.,* because the design from conception would be able to include necessary scenarios), the EPA cannot account for every scenario that may occur, especially given the potential intermittent nature of pneumatic pump emissions. Therefore, the EPA agrees with Petitioners and numerous commenters that it is appropriate to allow the owner or operator to demonstrate that it is technically infeasible to route pneumatic pump emissions to a control device or a process at any well site. The owner or operator must justify and provide professional or in-house engineering certification for any site where the control of pneumatic pump emissions is technically infeasible. The expansion of the technical infeasibility provision is reflected in 40 CFR 60.5393a(b), where we are removing paragraphs (b)(1) and (2).

In addition, we are amending paragraph (b)(5) to state that boilers and process heaters are not control devices for the purposes of the pneumatic pump standards. Two commenters stated that boilers and process heaters located at well sites are not inherently designed for the control of emissions and raised concerns that routing pneumatic pump emissions to these devices may result in frequent safety trips and burner flame instability (*i.e.,* high temperature limit shutdowns, loss of flame signal, etc.).[5] The comments further contend that requiring the technical infeasibility evaluation for every boiler and process heater located at a wellsite would result in unnecessary administrative burden since each such evaluation would be raising the same concerns described above. The EPA agrees with the commenters and has revised the standards to state that boilers and process heaters are not considered control devices for the purposes of controlling pneumatic pump emissions.

Additionally, the EPA is finalizing revisions to the certification requirements for the determination that it is technically infeasible to route emissions from pneumatic pumps to a control device or process. The 2016 NSPS subpart OOOOa requires certification of technical infeasibility by a qualified PE; however, the EPA proposed allowing this certification by either a PE or an in-house engineer because in-house engineers may be more knowledgeable about site design and control than a third-party PE. After considering the comments, some supporting and some opposing the proposal, the EPA continues to believe that certification by an in-house engineer is appropriate. We are, therefore, amending the rule to allow certification of technical infeasibility by either a PE or an in-house engineer with expertise on the design and operation of the pneumatic pump.

C. Storage Vessels

The storage vessel standards apply to individual storage vessels with the potential for VOC emissions of 6 tpy or greater. The 2016 NSPS subpart OOOOa requires a calculation of the potential for VOC emissions from individual storage vessels. In the proposal, the EPA sought to address instances where storage vessels are designed and operated as a manifolded battery and to address questions regarding where averaging emissions may be appropriate for the calculation of potential for VOC emissions. This final rule addresses the challenges of calculating the potential for VOC emissions from individual storage vessels that are part of a controlled battery by specifying separate calculation requirements for these storage vessels. Specifically, the final rule allows owners and operators to average the emissions across the number of storage vessels in a controlled battery provided that specific design and operational criteria are met. These specific design and operational criteria include requirements to manifold the vessels such that all vapors are shared between the headspace of the storage vessels and route the collected vapors through a CVS to a process or a control device with a destruction efficiency of at least 95.0 percent for VOC emissions, and must be included in legally and practically enforceable limits in a permit or other requirement established under a Federal, state, local, or tribal authority. Under the final rule, if these criteria are met, the owner or operator may calculate the average emissions from the individual storage vessels in that battery to determine if the average emissions are greater than 6 tpy. If the average emissions are greater than 6 tpy, then each of the individual storage vessels in that battery is a storage vessel affected facility. However, if the average emissions are less than 6 tpy, then none of the storage vessels in that battery are a storage vessel affected facility.

In addition, the final rule finalizes the proposed methods for calculating the potential for VOC emissions for storage vessels that do not meet the design and operational criteria specified above. Those storage vessels include individual storage vessels, as well as manifolded storage vessels that do not meet the criteria specified (*e.g.,* less than 95-percent control). These storage vessels must determine applicability by calculating their potential for VOC emissions in accordance with the methods specified in this final rule. The calculation of the potential for VOC emissions may take into account legally and practically enforceable limits on storage vessels but must be determined on an individual storage vessel basis without averaging emissions across the number of storage vessels at the site, even if the storage vessels are manifolded together. If the potential for VOC emissions from the individual storage vessel is greater than 6 tpy, then that storage vessel is a storage vessel affected facility. If the potential for VOC emissions from the individual storage vessel is less than 6 tpy, then that storage vessel is not a storage vessel affected facility.

The EPA is also amending the applicability criteria to clarify how owners and operators must determine the potential for VOC emissions for storage vessels located at onshore natural gas processing plants and compressor stations. The 2016 NSPS subpart OOOOa specifies that the calculation is based on the first 30 days of production to an individual storage vessel. We received comments on the proposal that this production period is not an accurate reflection of the potential for VOC emissions from storage vessels not located at a well site. Specifically, onshore natural gas processing plants and compressor stations are designed to process or transport a specific capacity of gas from multiple sites upstream of these facilities. The design capacity is based on planned growth with additional sites coming online over time, which means

[5] See Docket ID Item Nos. EPA–HQ–OAR–2017–0483–0781 and EPA–HQ–OAR–2017–0483–0801.

the storage vessels at gas processing plants and compressor stations do not receive the maximum throughput for which they are designed during the first 30 days of their operation. For these storage vessels, the commenters indicated they have been utilizing forecasting to predict future throughput and emissions when applying for an operating permit. The EPA agrees that the language in the 2016 NSPS subpart OOOOa does not appropriately capture the information needed to make an informed applicability determination for these storage vessels. Therefore, we are revising the final rule to clarify that, for storage vessels located at onshore natural gas processing plants and compressor stations, the potential for VOC emissions may be determined based on the emission limit or throughput limit (as an input for calculating the potential for VOC emissions), established in a legally and practicably enforceable limit, or based on the projected maximum average daily throughput determined using generally accepted engineering models, such as process simulations based on representative or actual liquid analysis to determine volumetric condensate rates from the storage vessels based on the maximum gas throughput capacity of each facility.

D. CVS

The 2016 NSPS subpart OOOOa requires that CVS be operated with no detectable emissions, as demonstrated through specific monitoring requirements associated with the specific affected facilities (*i.e.,* storage vessels, pneumatic pumps, centrifugal compressors, and reciprocating compressors). In the October 15, 2018, proposal, the EPA proposed amending the requirements for CVS associated with pneumatic pumps to require monthly AVO monitoring instead of the required annual Method 21 monitoring, thereby aligning the demonstration requirements for pneumatic pumps with those for storage vessels. 83 FR 52083. The EPA received comments recommending (1) retaining annual Method 21 as an option and (2) including OGI monitoring as an additional option because OGI is already being used to monitor fugitive emissions components at the well site and the CVS can readily be monitored at the same time. Based on these public comments, the EPA is amending the requirements for these no detectable emissions demonstrations for CVS for pneumatic pumps, with some changes from the proposal. Specifically, we are incorporating the option to demonstrate the pneumatic pump CVS is operated with no detectable emissions by an annual inspection using Method 21, monthly AVO monitoring, or OGI monitoring at the frequencies specified in section IV.E of this preamble.

The 2016 NSPS subpart OOOOa requires monthly AVO inspections on CVS for storage vessels to demonstrate operation with no detectable emissions. Similar to CVS for pneumatic pumps, the EPA is adding OGI monitoring at the frequencies specified in section IV.E of this preamble as another option for demonstrating no detectable emissions from CVS for storage vessels.

While the final rule provides these options for demonstrating the operation of the CVS with no detectable emissions, it is important to note that any detection with AVO or any visual image when using OGI is considered an indication of detected emissions. It is not the EPA's intent to allow owners and operators to conduct an inspection using OGI that results in the visual image of emissions, and then follow that inspection with AVO to conclude no emissions are present. If any of the options specified result in detected emissions, the standard of ''no detectable emissions'' is not met.

Additionally, the EPA is finalizing revisions to the certification requirements for CVS design. Specifically, we are amending the rule to allow either a PE or an in-house engineer with expertise on the design and operation of the CVS to certify the design and operation will meet the requirement to route all vapors to the control device or back to the process.

E. Fugitive Emissions at Well Sites and Compressor Stations

1. Monitoring Frequency

The 2016 NSPS subpart OOOOa requires semiannual monitoring and quarterly monitoring for fugitive emissions at well sites and compressor stations, respectively. The EPA proposed amending these monitoring frequencies as follows: (1) Annual monitoring for well sites with total combined production greater than 15 boe per day, (2) biennial monitoring for well sites with total combined production at or below 15 boe per day, and (3) co-proposed semiannual and annual monitoring for compressor stations. Additionally, the EPA proposed to allow owners and operators to stop monitoring at well sites when all of the major production and processing equipment is removed, such that the well site becomes a wellhead-only well site. After considering the comments and additional data, we are not finalizing the proposed changes to the monitoring frequencies for fugitive emissions components at well sites and compressor stations, with two exceptions explained below. The required fugitive monitoring frequencies for the collection of fugitive emissions components located at a well site or compressor station are as follows:

- Semiannual monitoring for well sites, excluding well sites with total production for the site at or below 15 boe per day (herein referred to as ''low production well sites'') and well sites on the Alaska North Slope;
- Semiannual monitoring for compressor stations, excluding those on the Alaska North Slope;
- Annual monitoring for well sites (excluding low production well sites) and compressor stations located on the Alaska North Slope; and
- Monitoring may be stopped once all major production and processing equipment is removed from a well site such that it contains only one or more wellheads.
- Low production well sites are excluded from fugitive monitoring requirements as long as the total production of the well site remains at or below 15 boe per day, as determined on a rolling 12-month basis and demonstrated by the records specified in the final rule. To determine if a well site is a low production well site, the EPA is finalizing the following calculation periods:
  - For a well site that newly triggers the fugitive emissions requirements of the NSPS after the effective date of the rule, or a well site that triggered the 2016 NSPS subpart OOOOa requirements within 11 months prior to the effective date of the rule but does not have 12-months' worth of production data, the total well site production calculation is based on the first 30 days of production;
  - For a well site subject to the fugitive emissions requirements that subsequently has production decline, the total well site production calculation is based on a rolling 12-month average;
  - For a well site that has previously been determined to be low production but later takes an action (*e.g.,* drills a new well, performs a well workover, etc.) that may increase production, the total well site production calculation is based on the first 30 days of production following completion of the action. This re-determination must be completed at any time an action occurs, regardless of the original startup of production date.

2. Modification

The October 15, 2018, proposal did not propose amendments to the events that constitute modifications of the collection of fugitive emissions components located at a well site or a compressor station but did take comment on whether additional clarification is necessary. The EPA's consideration of the comments received did not result in changes to modifications for well sites and compressor stations, therefore, this final rule retains the events currently identified in the 2016 NSPS subpart OOOOa that qualify as modifications of the collection of fugitive emissions components located at a well site or a compressor station.

The 2016 NSPS subpart OOOOa specifies that, for the purposes of fugitive emissions components at a well site, a modification occurs when (1) a new well is drilled at an existing well site, (2) a well is hydraulically fractured at an existing well site, or (3) a well is hydraulically refractured at an existing well site. 40 CFR 60.5365a(i). Because this provision does not specifically address modifications of a well site that is a separate tank battery surface site, the EPA proposed language to address modifications of separate tank battery surface sites. Specifically, the EPA proposed that a modification of a well site that is a separate tank battery surface site occurs when (1) any of the actions listed above for well sites occurs at an existing separate tank battery surface site, (2) a well modified as described above sends production to an existing separate tank battery surface site, or (3) a well site subject to the fugitive emissions requirements removes all major production and processing equipment such that it becomes a wellhead-only well site and sends production to an existing separate tank battery surface site. After considering the comments received related to the proposed modification language relevant for separate tank battery surface sites, the EPA is finalizing this provision as proposed.

3. Initial Monitoring for Well Sites and Compressor Stations

The 2016 NSPS subpart OOOOa requires fugitive emissions monitoring to begin within 60 days of startup of production (for well sites) or startup of a compressor station. The October 15, 2018, proposal did not propose any change to this requirement but solicited comment identifying specific reasons why a change might be appropriate. 83 FR 52075. We received comments stating that well sites and compressor stations do not achieve normal operating conditions within the first 60 days of startup. Commenters suggested a range of options from 90 days to 180 days. Based on these comments, the EPA agrees that maintaining the requirement to conduct initial monitoring within 60 days of startup would not provide as effective of a survey as providing additional time to allow the well site or compressor station to reach normal operating conditions. The purpose of the initial monitoring is to identify any issues associated with installation and startup of the well site or compressor station. By providing sufficient time to allow owners and operators to conduct the initial monitoring survey during normal operating conditions, the EPA expects that there will be more opportunity to identify and repair sources of fugitive emissions, whereas, a partially operating site may result in missed emissions that remain unrepaired for a longer period of time. The additional 30 days provided in this final rule will still allow for identification and mitigation of fugitive emissions in a timely manner. Therefore, the final rule requires that initial monitoring be completed within 90 days after the startup of production for well sites and 90 days after the startup of a compressor station. Additionally, for low production well sites that take an action which subsequently increases production above 15 boe per day based on the first 30 days of production following the action, the final rule requires that initial monitoring be completed within 90 days after the startup of production following the action.

4. Repair Requirements

This final rule amends the fugitive emissions repair requirements. The 2016 NSPS subpart OOOOa requires repair within 30 days of identifying fugitive emissions and a resurvey to verify that the repair was successful within 30 days of the repair. In the proposal, the EPA proposed to require a first attempt at repair within 30 days of identifying fugitive emissions and final repair, including the resurvey to verify repair, within 60 days of identifying fugitive emissions. We proposed these revisions because stakeholders raised questions on whether emissions identified during the resurvey would result in noncompliance with the repair requirement. The EPA agreed that repairs should be verified as successful prior to the repair deadline, therefore, we proposed a definition of repair that includes the resurvey. The net result of the proposal was that sources would have up to 60 days to complete repairs, which was an increase from the 2016 NSPS subpart OOOOa requirement of 30 days. We received comments from owners and operators that a total of 60 days was not necessary to complete a successful repair, therefore, this final rule amends the fugitive emissions repair requirements with changes from the proposal. Specifically, we are finalizing the proposal that a first attempt at repair is required within 30 days of identifying fugitive emissions and requiring final repair within 30 days of the first attempt at repair. While this final rule would still allow up to a total of 60 days to complete repairs, several owners and operators indicated in their comments that the majority of repairs are completed onsite during the time of the monitoring survey. We are also finalizing as proposed definitions for the terms ‘‘first attempt at repair’’ and ‘‘repaired.’’ Specifically, the definition of ‘‘repaired’’ includes the verification of successful repair through a resurvey of the fugitive emissions component.

The EPA is also amending the requirements for when delayed repairs must be completed. The 2016 NSPS subpart OOOOa, as amended on March 12, 2018,[6] specifies that where the repair of a fugitive emissions component is ‘‘technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair must be completed during the next scheduled compressor station shutdown, well shutdown, well shut-in, after a planned vent blowdown, or within 2 years, whichever is earlier.’’[7] The EPA did not propose any additional revisions to this provision, but solicited comment on whether additional changes were necessary. 83 FR 52076. We received comments expressing concerns with requiring repairs during the next scheduled compressor station shutdown, without regard to whether the shutdown is for maintenance purposes. The commenters stated that repairs must be scheduled and that where a planned shutdown is for reasons other than scheduled maintenance, completion of the repairs during that shutdown may be difficult and disrupt gas transmission. The EPA agrees that requiring the completion of delayed repairs only during those scheduled compressor station shutdowns where maintenance activities are scheduled is reasonable and anticipates that these maintenance shutdowns occur on a regular schedule. Therefore, the final rule requires completion of delayed repairs during the ‘‘next scheduled compressor station

[6] 83 FR 10638.

[7] 40 CFR 60.5397a(h)(2).

shutdown for maintenance, scheduled well shutdown, scheduled well shut-in, after a scheduled vent blowdown, or within 2 years, whichever is earliest.''

5. Definitions Related to Fugitive Emissions at Well Sites and Compressor Stations

The EPA is finalizing, as proposed, amendments to the definition of well site, for purposes of fugitive emissions monitoring, to exclude equipment owned by third parties and oilfield wastewater disposal wells (referred to as saltwater disposal wells in the proposal). Additionally, based on information received in public comments, the EPA is also amending the definition to exclude oilfield disposal wells used for solid waste disposal. The amended definition for ''well site'' excludes third party equipment from the fugitive emissions requirements by excluding ''the flange immediately upstream of the custody meter assembly and equipment, including fugitive emissions components located downstream of this flange.'' To clarify this exclusion, the final rule defines ''custody meter'' as the meter where natural gas or hydrocarbon liquids are measured for sales, transfers, and/or royalty determination, and the ''custody meter assembly'' as an assembly of fugitive emissions components, including the custody meter, valves, flanges, and connectors necessary for the proper operation of the custody meter, as proposed. The exclusion does not extend to other third-party equipment at a well site that is not associated with the custody meter and custody meter assembly (*e.g.,* dehydrators).

This final rule further amends the definition of a well site to exclude UIC Class I oilfield disposal wells and UIC Class II oilfield wastewater disposal wells. The EPA proposed excluding UIC Class II oilfield wastewater disposal wells because of our understanding that they have negligible fugitive emissions. 83 FR 52077. Commenters suggested that we also should exclude UIC Class I oilfield disposal wells for the same reasons. Both types of disposal wells are permitted through UIC programs under the Safe Drinking Water Act for surface and groundwater protection. The EPA agrees with the commenters that the potential fugitive methane and VOC emissions from UIC Class I oilfield disposal wells are low. Therefore, the final rule includes a definition for UIC Class I oilfield disposal wells. The definition for a UIC Class I oilfield disposal well is a well with a UIC Class I permit that meets the definition in 40 CFR 144.6(a)(2) and receives eligible fluids from oil and natural gas exploration and production operations. Additionally, the EPA is finalizing, as proposed, the definition of UIC Class II oilfield wastewater disposal wells. The definition for a UIC Class II oilfield wastewater disposal well is a well with a UIC Class II permit where wastewater resulting from oil and natural gas production operations is injected into underground porous rock formations not productive of oil or gas, and sealed above and below by unbroken, impermeable strata. Consequently, UIC Class I and UIC Class II disposal facilities without wells that produce oil or natural gas are not considered well sites for the purposes of fugitive emissions requirements.

The EPA is also finalizing, as proposed, the definition of startup of production as it relates to fugitive emissions requirements. Specifically, startup of production is defined as 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, except as otherwise provided herein. For the purposes of the fugitive monitoring requirements of § 60.5397a, startup of production means the beginning of the continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water.

F. AMEL

1. Incorporation of Emerging Technologies

The EPA is amending the application requirements for requesting the use of an AMEL for well completions, reciprocating compressors, and the collection of fugitive emissions components located at a well site or compressor station. Applications for an AMEL may be submitted by, among others, owners or operators of affected facilities, manufacturers or vendors of leak detection technologies, or trade associations. The application must provide sufficient information to demonstrate that the AMEL achieves emission reductions at least equivalent to the work practice standards in this rule. At a minimum, the application should include field data that encompass seasonal variations, and may be supplemented with modeling analyses, test data, and/or other documentation. The specific work practice(s), including performance methods, quality assurance, the threshold that triggers action, and the mitigation thresholds are also required as part of the application. For example, for a technology designed to detect fugitive emissions, information such as the detection criteria that indicate fugitive emissions requiring repair, the time to complete repairs, and any methods used to verify successful repair would be required.

2. Incorporation of State Fugitive Emissions Programs

This final rule includes alternative fugitive emissions standards for specific state fugitive emissions programs that the EPA has concluded are at least equivalent to the fugitive emissions monitoring and repair requirements at 40 CFR 60.5397a(e), (f), (g), and (h). These alternative fugitive emissions standards may be adopted for certain individual well sites or compressor stations that are subject to fugitive emissions monitoring and repair so long as the source complies with specified Federal requirements applicable to each approved alternative state program. For example, a well site that is subject to the requirements of Pennsylvania General Permit 5A, section G, effective August 8, 2018, could comply with those standards in lieu of the monitoring, repair, recordkeeping, and reporting requirements in the NSPS. However, the company must develop and maintain a fugitive emissions monitoring plan, as required in 40 CFR 60.5397a(c) and (d), and must monitor all of the fugitive emissions components, as defined in 40 CFR 60.5430a, regardless of the components that must be monitored under the alternative standard. Additionally, the facility must submit, as an attachment to its annual report for NSPS subpart OOOOa, the report that is submitted to its state in the format submitted to the state, or the information required in the report for NSPS subpart OOOOa if the state report does not include site-level monitoring and repair information. If a well site is located in the state but is not subject to the state requirements for monitoring and repair (*i.e.,* not obligated to monitor or repair fugitive emissions), then the well site must continue to comply with the requirements of 40 CFR 60.5397a in its entirety.

In addition to providing alternative fugitive emissions standards for well sites and compressor stations located in California, Colorado, Ohio, Pennsylvania, and Texas, and well sites in Utah, these amendments provide application requirements to request alternative fugitive emissions standards as state, local, and tribal programs continue to develop. Applications for alternative fugitive emissions standards based on state, local, or tribal programs may be submitted by any interested person, including individuals, corporations, partnerships, associations, states, or municipalities. Similar to the applications for AMEL for emerging technologies, the application must include sufficient information to demonstrate that the alternative fugitive emissions standards achieve emissions reductions at least equivalent to the fugitive emissions monitoring and repair requirements in this rule. At a minimum, the application must include the monitoring instrument, monitoring procedures, monitoring frequency, definition of fugitive emissions requiring repair, repair requirements, recordkeeping, and reporting requirements. If any of the sections of the regulations or permits approved as alternative fugitive emissions standards are changed at a later date, the state must follow the procedures outlined in 40 CFR 60.5399a to apply for a new evaluation of equivalency.

G. Onshore Natural Gas Processing Plants

1. Capital Expenditure

The EPA is amending the definition of ''capital expenditure'' at 40 CFR 50.5430a by replacing the equation used to determine the percent of replacement cost, ''Y.'' The 2016 NSPS subpart OOOOa contains a definition for ''Y'' that would result in an error, thus, making it difficult to determine whether a capital expenditure had occurred. The EPA proposed to revise the base year in the equation for ''Y'' with the year 2015 and to define ''Y'' as equal to 1 for facilities constructed in the year 2015. Additionally, we solicited comment on an alternative approach that would utilize CPI. While the EPA proposed these specific amendments to the equation used to determine the value of ''Y,'' we received public comments that supported the alternative approach which would more appropriately reflect inflation than the original equation. The EPA solicited comment on this alternative and is finalizing the alternative because we agree it is appropriate. The final equation for ''Y'' is based on the CPI, where ''Y'' equals the CPI of the date of construction divided by the most recently available CPI of the date of the project, or ''CPI_N/CPI_{PD}.'' Further, the final rule specifies that the ''annual average of the consumer price index for all urban consumers (CPI–U), U.S. city average, all items'' must be used for determining the CPI of the year of construction, and the ''CPI–U, U.S. city average, all items'' must be used for determining the CPI of the date of the project. This amendment clarifies that the comparison of costs is between the original date of construction of the process unit and the date of the project which adds equipment to the process unit.

2. Equipment in VOC Service Less Than 300 Hours per Year (hr/yr)

The October 15, 2018, proposal included an exemption from the requirements for equipment leaks at onshore natural gas processing plants. Specifically, the EPA proposed an exemption from monitoring for equipment that an owner or operator designates as being in VOC service less than 300 hr/yr. 83 FR 52086. The EPA received comments supporting this proposed exemption; therefore, we are amending the final rule as proposed. This exemption applies to equipment at onshore natural gas processing plants that is used only during emergencies, used as a backup, or that is in service only during startup and shutdown.

3. Initial Compliance Period

The EPA is amending NSPS subpart OOOOa to specify that the initial compliance deadline for the equipment leak standards for onshore natural gas processing plants is 180 days. Specifically, the EPA is including in NSPS subpart OOOOa the provision requiring compliance ''as soon as practicable, but no later than 180 days after initial startup'' that is already in 40 CFR 60.632(a), which is part of subpart KKK of the part, ''Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants for which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or before August 23, 2011'' (NSPS subpart KKK). In 2012, the EPA revised the standards in NSPS subpart KKK with the promulgation of NSPS subpart OOOO [8] by lowering the leak definition for valves from 10,000 parts per million (ppm) to 500 ppm and requiring the monitoring of connectors. 77 FR 49490, 49498. While no changes to the compliance deadlines were made or discussed in NSPS subpart OOOO, 40 CFR 60.632(a) was not included in NSPS subpart OOOO and, as a result, was also not included in NSPS subpart OOOOa. During the rulemaking for NSPS subpart OOOOa, the EPA declined a request to include the language in 40 CFR 60.632(a) in NSPS subpart OOOOa, explaining that such inclusion was not necessary because NSPS subpart OOOOa already incorporates by reference a similar statement (*i.e.,* 40 CFR 60.482–1a(a)) which requires each owner and operator to ''demonstrate compliance . . . within 180 days of initial startup,'' 80 FR 56593, 56647–8. In reassessing the issue, the EPA notes that NSPS subpart KKK includes both 40 CFR 60.632(a) and 40 CFR 60.482–1(a), a provision that is the same as 40 CFR 60.482–1a(a), suggesting that at the time of promulgation of NSPS subpart KKK, the EPA did not think that 40 CFR 60.482–1(a) (and 40 CFR 60.482–1a(a)) make 40 CFR 60.632(a) redundant or unnecessary. To remain consistent with NSPS subpart KKK, the EPA is amending NSPS subpart OOOOa to include a provision similar to 40 CFR 60.632(a).

The final rule requires monitoring to begin as soon as practicable, but no later than 180 days after the initial startup of a new, modified, or reconstructed process unit at an onshore natural gas processing plant. Once started, monitoring must continue with the required schedule. For example, if pumps are monitored by month 3 of the initial startup period, then monthly monitoring is required from that point forward. This initial compliance period is different than the compliance requirements for newly added pumps and valves within a process unit that is already subject to a leak detection and repair (LDAR) program. Initial monitoring for those newly added pumps and valves is required within 30 days of the startup of the pump or valve (*i.e.,* when the equipment is first in VOC service).

H. Sweetening Units

This final rule revises the applicability criteria for the SO_2 standards for sweetening units to correctly define an affected facility as any onshore sweetening unit that processes natural gas produced from either onshore or offshore wells. Sweetening units are used to convert hydrogen sulfide (H_2S) in acid gases (*i.e.,* H_2S and CO_2) that are separated from natural gas by a sweetening process (*e.g.,* amine treatment) into elemental sulfur in the Claus process.[9] These units can exist anywhere in the production and processing segment of the source category, including as stand-alone processing facilities that do not extract or fractionate natural gas liquids from field gas. The SO_2 standards for onshore sweetening units were first promulgated in 1985 and codified in 40 CFR part 60, subpart LLL. In 2012,

[8] ''Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution for Which Construction, Modification or Reconstruction Commenced After August 23, 2011, and on or before September 18, 2015.''

[9] See Docket ID Item No. EPA–HQ–OAR–2010–0505–0045.

based on our review of the standards, the EPA tightened the SO_2 standards, which were codified in NSPS subpart OOOO and later carried over to NSPS subpart OOOOa. In the process of finalizing this current rulemaking to amend NSPS subpart OOOOa, the EPA discovered that NSPS subpart OOOOa inexplicably limits the applicability of the SO_2 standards to only those sweetening units that are located at onshore natural gas processing plants, which NSPS subpart OOOOa defines as ''any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. . . .'' 40 CFR 60.5430a. NSPS subpart LLL did not contain this limitation, and the EPA did not offer any rationale for creating it during the promulgation of either NSPS subpart OOOO or NSPS subpart OOOOa, nor can we identify any reason why the extraction of natural gas liquids relates in any way to the SO_2 standards such that the standards should only apply to sweetening units located at onshore natural gas processing plants engaged in extraction or fractionation activities. Sweetening units emit SO_2 in the same manner, regardless of whether they are located at an onshore natural gas processing plant or at processing facilities without extraction or fractionation activities. Therefore, the EPA concludes that the limitation was made in error and is now correcting the error by revising the affected facility description for the SO_2 standards to include all onshore sweetening units that process natural gas produced from either onshore or offshore wells.

I. Recordkeeping and Reporting

The EPA is amending NSPS subpart OOOOa to streamline the recordkeeping and reporting requirements as discussed below for the specified affected facilities. These amendments reflect consideration of the public comments received on the proposal.

1. Well Completions

For each well site affected facility that routes flowback entirely through one or more production separators, owners and operators are only required to record and report the following elements:

- Well Completion ID;
- Latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983;
- U.S. Well ID;
- The date and time of the onset of flowback following hydraulic fracturing or refracturing or identification that the well immediately starts production; and
- The date and time of the startup of production.

For periods where salable gas is unable to be separated, owners and operators will also be required to record and report the date and time of onset of flowback, the duration and disposition of recovery, the duration of combustion and venting (if applicable), reasons for venting (if applicable), and deviations.

2. Fugitive Emissions at Well Sites and Compressor Stations

For each collection of fugitive emissions components located at a well site or compressor station, the EPA is amending the recordkeeping and reporting requirements as follows:

- Revise the requirements in 40 CFR 60.5397a(d)(1) to require inclusion of procedures that ensure all fugitive emissions components are monitored during each survey within the monitoring plan.
- Remove the requirement to maintain records of a digital photo of each monitoring survey performed, captured from the OGI instrument used for monitoring.
- Remove the requirement to maintain records of the number and type of fugitive emissions components or digital photo of fugitive emissions components that are not repaired during the monitoring survey. These records are not required once repair is completed and verified with a resurvey.
- Require records of the total well site production for low production well sites.
- Require records of the date of first attempt at repair and date of successful repair.
- Revise reporting to specify the type of site (*i.e.,* well site, low production well site, or compressor station) and when the well site changes status to a wellhead-only well site.
- Remove requirement to report the name or ID of operator performing the monitoring survey.
- Remove requirement to report the number and type of difficult-to-monitor and unsafe-to-monitor components that are monitored during each monitoring survey.
- Remove requirement to report the ambient temperature, sky conditions, and maximum wind speed.
- Remove requirement to report the date of successful repair.
- Remove requirement to report the type of instrument used for resurvey.

In addition to streamlining the recordkeeping and reporting requirements, the EPA is also finalizing the form that is used for submitting annual reports through the Compliance and Emissions Data Reporting Interface (CEDRI) with this final rule. Per the requirement in 40 CFR 60.5420a(b)(11), affected facilities must submit all subsequent reports via CEDRI, once the form has been available in CEDRI for at least 90 calendar days. The EPA anticipates that the deadline to begin submitting subsequent annual reports required by 40 CFR 60.5420a(b) through CEDRI will be [INSERT DATE 90 DAYS AFTER DATE OF PUBLICATION IN THE **FEDERAL REGISTER**]. However, owners and operators should verify the date that the form becomes available in CEDRI by checking the ''Initial Availability Date'' listed on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*).

J. Technical Corrections and Clarifications

The EPA is revising NSPS subpart OOOOa to include the following technical corrections and clarifications.

- Revise 40 CFR 60.5385a(a)(1), 60.5410a(c)(1), 60.5415a(c)(1), and 60.5420a(b)(4)(i) and (c)(3)(i) to clarify that hours or months of operation at reciprocating compressor facilities must be measured beginning with the date of initial startup, the effective date of the requirement (August 2, 2016), or the last rod packing replacement, whichever is latest.
- Revise 40 CFR 60.5393a(b)(3)(ii) to correctly cross-reference paragraph (b)(3)(i) of that section.
- Revise 40 CFR 60.5397a(c)(8) to clarify the calibration requirements when Method 21 of appendix A–7 to part 60 is used for fugitive emissions monitoring.
- Revise 40 CFR 60.5397a(d)(3) to correctly cross-reference paragraphs (g)(3) and (4) of that section.
- Revise 40 CFR 60.5401a(e) to remove the word ''routine'' to clarify that pumps in light liquid service, valves in gas/vapor service and light liquid service, and pressure relief devices in gas/vapor service within a process unit at an onshore natural gas processing plant located on the Alaska North Slope are not subject to any monitoring requirements.
- Revise 40 CFR 60.5410a(e) to correctly reference pneumatic pump affected facilities located at a well site as opposed to pneumatic pump affected facilities not located at a natural gas processing plant (which would include those not at a well site). This correction reflects that the 2016 NSPS subpart OOOOa did not finalize requirements for pneumatic pumps at gathering and boosting compressor stations. 81 FR 35850.

• Revise 40 CFR 60.5411a(a)(1) to remove the reference to § 60.5412a(a) and (c) for reciprocating compressor affected facilities.

• Revise 40 CFR 60.5411a(d)(1) to remove the reference to storage vessels, as this paragraph applies to all the sources listed in 40 CFR 60.5411a(d), not only storage vessels.

• Revise 40 CFR 60.5412a(a)(1) and (d)(1)(iv) to clarify that all boilers and process heaters used as control devices on centrifugal compressors and storage vessels must introduce the vent stream into the flame zone. Additionally, revise 40 CFR 60.5412a(a)(1)(iv) and (d)(1)(iv)(D) to clarify that the vent stream must be introduced with the primary fuel or as the primary fuel to meet the performance requirement option. This is consistent with the performance testing exemption in 40 CFR 60.5413a and continuous monitoring exemption in 40 CFR 60.5417a for boilers and process heaters that introduce the vent stream with the primary fuel or as the primary fuel.

• Revise 40 CFR 60.5412a(c) to correctly reference both paragraphs (c)(1) and (2) of that section, for managing carbon in a carbon adsorption system.

• Revise 40 CFR 60.5413a(d)(5)(i) to reference fused silica-coated stainless steel evacuated canisters instead of a specific name brand product.

• Revise 40 CFR 60.5413a(d)(9)(iii) to clarify the basis for the total hydrocarbon span for the alternative range is propane, just as the basis for the recommended total hydrocarbon span is propane.

• Revise 40 CFR 60.5413a(d)(12) to clarify that all data elements must be submitted for each test run.

• Revise 40 CFR 60.5415a(b)(3) to reference all applicable reporting and recordkeeping requirements.

• Revise 40 CFR 60.5416a(a)(4) to correctly cross-reference 40 CFR 60.5411a(a)(3)(ii).

• Revise 40 CFR 60.5417a(a) to clarify requirements for controls not specifically listed in paragraph (d) of that section.

• Revise 40 CFR 60.5422a(b) to correctly cross-reference 40 CFR 60.487a(b)(1) through (3) and (b)(5).

• Revise 40 CFR 60.5422a(c) to correctly cross-reference 40 CFR 60.487a(c)(2)(i) through (iv) and (c)(2)(vii) through (viii).

• Revise 40 CFR 60.5423a(b) to simplify the reporting language and clarify what data are required in the report of excess emissions for sweetening unit affected facilities.

• Revise 40 CFR 60.5430a to remove the phrase ''including but not limited to'' from the ''fugitive emissions component'' definition. During the 2016 NSPS subpart OOOOa rulemaking, we stated in a response to comment that we are removing this phrase,[10] but we did not do so in that rulemaking and are finalizing that change in this final rule.

• Revise 40 CFR 60.5430a to remove the phrase ''at the sales meter'' from the ''low pressure well'' definition to clarify that when determining the low pressure status of a well, pressure is measured within the flow line, rather than at the sales meter.

• Revise Table 3 to correctly indicate that the performance tests in 40 CFR 60.8 do not apply to pneumatic pump affected facilities.

• Revise Table 3 to include the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station in the list of exclusions for notification of reconstruction.

• Revise 40 CFR 60.5393a(f), 60.5410a(e)(8), 60.5411a(e), 60.5415a(b) introductory text and (b)(4), 60.5416a(d), 60.5420a(b) introductory text and (b)(13), and introductory text in §§ 60.5411a and 60.5416a, to remove language associated with the administrative stay we issued under section (d)(7)(B) of the CAA in ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Grant of Reconsideration and Partial Stay'' (June 5, 2017). The administrative stay was vacated by the U.S. Court of Appeals for the District Of Columbia Circuit on July 3, 2017.

V. Significant Changes Since Proposal

This section identifies significant changes since the proposed rulemaking. These changes reflect the EPA's consideration of over 500,000 comments submitted on the proposal and other information received since the proposal. In this section, we discuss the significant changes since proposal by affected facility type and the rationales for those changes. Additional information related to these changes, such as specific comments and our responses, is in section VI of this preamble and in materials available in the docket.[11]

A. Storage Vessels

In the October 15, 2018, proposal, the EPA proposed clarifications on how to calculate the potential for VOC emissions for purposes of determining whether a storage vessel has the potential for 6 tpy or more of VOC emissions and, therefore, is an affected facility subject to the storage vessels standards under the 2016 NSPS subpart OOOOa. Specifically, the EPA proposed amendments to the definition of ''maximum average daily throughput'' that provided distinct methodologies for calculating the throughput of an individual storage vessel based on how throughput is measured and recorded. We proposed the amendments because owners and operators continued to express confusion over how to calculate this throughput.

Numerous commenters [12] expressed objections to several aspects of the proposed amendments, particularly to the EPA's assumption that averaging emissions across storage vessels in a controlled battery would underestimate a storage vessel's potential VOC emissions. The commenters explained why averaging across storage vessels in controlled batteries has a sound basis in engineering and addresses the EPA's concern about flash emissions, which constitute most of the emissions from storage vessels.

Specifically, the commenters pointed out that tank batteries typically share vapor space (the tank volume above the liquid) and joint piping used to collect generated vapors, which are then routed back to a process or conveyed to a control device, when one is used, or vented through one common pressure relief valve (PRV). For purposes of this discussion, the EPA considers this configuration as a manifolded system that collects and routes vapors across the headspace. (This is different than liquid manifolded systems where liquids can be introduced to any tank in the system.) The commenters noted that vapors flow both into and out of each tank within the battery and into overflow piping on a continuous basis, and vapors will always flow from high pressure areas to low pressure areas when flow is mechanically unrestricted. The commenters explained that, in this configuration, the flash emissions from the first tank will flow into the other tanks and vent line space associated with the battery until the total pressure in the system exceeds the back-pressure of the flare or other control device, or in systems without controls, the PRV.

[10] See Docket ID Item No. EPA–HQ–OAR–2010–0505–7632, Chapter 4, page 4–319.

[11] See Response to Comments (RTC) document and technical support documents (TSD) in Docket ID No. EPA–HQ–OAR–2017–0483.

[12] See Docket ID Item Nos. EPA–HQ–OAR–2017–0483–0773, EPA–HQ–OAR–2017–0483–0775, EPA–HQ–OAR–2017–0483–0780, EPA–HQ–OAR–2017–0483–0801, EPA–HQ–OAR–2017–0483–0996, EPA–HQ–OAR–2017–0483–0999, EPA–HQ–OAR–2017–0483–1006, EPA–HQ–OAR–2017–0483–1009, EPA–HQ–OAR–2017–0483–1236, EPA–HQ–OAR–2017–0483–1243, EPA–HQ–OAR–2017–0483–1248, EPA–HQ–OAR–2017–0483–1261, EPA–HQ–OAR–2017–0483–1343, and EPA–HQ–OAR–2017–0483–1578.

The commenters asserted that only then will the emissions (*i.e.,* the vapors) be released from the PRV if uncontrolled; routed back to a process; or combusted by the control equipment. Therefore, the commenters suggested that because the vapors from individual storage vessels are comingled and not individually emitted from the originating storage vessels, it is appropriate to allow sources to average the emissions across the number of storage vessels in the controlled battery in order to attribute emissions to individual storage vessels.

After considering these comments and subsequent conversations with the commenters,[13] the EPA reevaluated the proposal. Based on this review, the EPA agrees with the commenters that, in certain situations, averaging emissions across a controlled battery may be appropriate for purposes of determining whether to subject the storage vessels in the tank battery to the storage vessel standards in NSPS subpart OOOOa.

In order to fully understand where averaging of emissions across a controlled battery may be appropriate, under this final rule, for purposes of determining whether to subject the storage vessels in the controlled battery to the storage vessel standards in NSPS subpart OOOOa, the EPA considered the level of control that would be achieved where uncontrolled potential emissions are greater than 6 tpy. The standards in the 2016 NSPS subpart OOOOa require reducing uncontrolled emissions from individual storage vessel affected facilities by 95.0 percent.

For controlled batteries, as liquids are introduced to a storage vessel in the system, the vapors transfer to the piping, or common header, enter the common vapor space, and commingle with vapors from other storage vessels in the manifolded system. When the combined vapor pressure in the common header reaches a specified set point, the vapors are typically conveyed through a CVS to either a vapor recovery unit (which routes vapors back to a process) or a control device. Where this controlled battery is designed and operated to route the vapors in this manner, emissions from an individual storage vessel within the controlled battery are indistinguishable from emissions from other storage vessels within the controlled battery; each individual storage vessel does not directly emit (*e.g.,* flash emissions) to the atmosphere. These controlled batteries are typically subject to specific design and operational criteria through a legally and practicably enforceable limit (*e.g.,* through permits or other requirements established through Federal, state, local, or tribal authority). To the extent that the control, through the battery's design and operation, already reduces 95 percent or more of the VOC emissions, no additional emission reductions would be achieved by subjecting each individual storage vessel in the controlled battery operating under legally and practicably enforceable limits to the storage vessel standards in the 2016 NSPS subpart OOOOa. However, the 2016 NSPS subpart OOOOa considers any storage vessel with the potential for VOC emissions greater than 6 tpy, including those with legally and practicably enforceable limits, a storage vessel affected facility. This final rule does not change that 6 tpy applicability threshold, but it does include specific criteria that must be included in the legally and practicably enforceable limit before averaging of emissions will be allowed for the purposes of determining whether the potential for VOC emissions from the individual storage vessels in a controlled tank battery is above the 6 tpy threshold. Specifically, the legally and practicably enforceable limit must require the storage vessels to be (1) manifolded together with piping such that all vapors are shared among the headspaces of the storage vessels, (2) equipped with a CVS that is designed, operated, and maintained to route vapors back to the process or to a control device, and (3) designed and operated to route vapors back to the process or to a control device that reduces VOC emissions by at least 95.0 percent. The EPA concludes that averaging emissions across the number of storage vessels in a controlled battery subject to the design and operational criteria specified above, through a legally and practicably enforceable limit, is the appropriate way to determine if the storage vessels in that battery are affected facilities under NSPS subpart OOOOa. Where the average VOC emissions across the number of storage vessels in the controlled battery is 6 tpy or greater, all of the storage vessels in the controlled battery are storage vessel affected facilities and subject to the requirements for storage vessels in NSPS subpart OOOOa. However, where the average emissions are less than 6 tpy, none of the storage vessels in the controlled battery are storage vessels affected facilities.

For storage vessels that do not meet all of the design and operational criteria specified in this final rule, which includes single storage vessels (whether controlled or not) and storage vessels that are connected in some way but do not meet all of the criteria described above, the final rule requires owners and operators to calculate the potential for VOC emissions on an individual storage vessel basis to determine if the storage vessel is a storage vessel affected facility, as proposed. Where the potential for VOC emissions from a storage vessel is 6 tpy or greater, the storage vessel is a storage vessel affected facility. We have not revised the BSER for storage vessel affected facilities; as a result, the storage vessel standards in the 2016 NSPS subpart OOOOa remain applicable to these storage vessels if their potential for VOC emissions is 6 tpy or greater, based on each individual storage vessel and without averaging across the storage vessels at the site.

The final rule continues to require that an owner or operator calculate the potential for VOC emissions using generally accepted methods for estimating emissions based on the maximum average daily throughput. In this final rule, the EPA is amending the definition of maximum average daily throughput to specify how to determine throughput for the calculation of the potential for VOC emissions. Specifically, this amended definition specifies how storage vessels that commence construction, reconstruction, or modification after the effective date of this final rule must determine the throughput to each individual storage vessel in order to calculate the potential for VOC emissions. This definition is relevant to the individual storage vessels or connected storage vessels that do not meet the specified design and operational criteria defined for controlled tank batteries (*i.e.,* tank batteries that are allowed to average emissions across the tanks in the battery).

In summary, this final rule amends the definition of ''maximum average daily throughput,'' to specify how the potential for VOC emissions are calculated. Additionally, this final rule allows for a calculation of the average VOC emissions to determine the applicability of the storage vessel standards to storage vessels in controlled batteries where specific design and operational criteria are incorporated as legally and practicably enforceable requirements into a permit or other requirement established under Federal, state, local, or tribal authority. The specific design and operational criteria are as follows: (1) The storage vessels are manifolded together with piping such that all vapors are shared

[13] See Memoranda for March 27, 2019 Meeting with American Petroleum Institute, April 9, 2019 Meeting with Hess, and May 1, 2019 Meeting with GPA Midstream located at Docket ID No. EPA–HQ–OAR–2017–0483.

between the headspace of the storage vessels, (2) the storage vessels are equipped with a CVS that is designed, operated, and maintained to route collected vapors back to the process or to a control device, and (3) collected vapors are routed to a process or a control device that achieves at least 95.0-percent control of VOC emissions. If the potential for VOC emissions (or average emissions where applicable) is greater than or equal to 6 tpy, the storage vessel is a storage vessel affective facility.

The amendments discussed above, including the definition of ''maximum average daily throughput,'' apply to storage vessels that commence construction, reconstruction, or modification after the effective date of this final rule, which is November 16, 2020. Owners and operators of storage vessels that commenced construction, reconstruction, or modification after September 18, 2015, and on or before November 16, 2020 may still have uncertainty regarding whether they determined their applicability appropriately. If so, these owners and operators should contact the EPA if they have questions regarding how they previously determined applicability for these sources.

B. Fugitive Emissions at Well Sites and Compressor Stations

The October 15, 2018, proposal included various proposed amendments to the fugitive emissions standards. Two major aspects of those proposed amendments were (1) reduction in the monitoring frequency for well sites and compressor stations and (2) revisions to the monitoring plan, recordkeeping, and reporting requirements. This final rule includes changes from the proposal in both areas. First, the EPA is not finalizing the proposed annual monitoring frequency at non-low production well sites. As explained in more detail below, the EPA concluded that the three areas of uncertainty that were the basis for proposing amendments to the monitoring frequencies for well sites and compressor stations did not result in an overestimate of the cost-effectiveness of the monitoring frequencies in the 2016 NSPS subpart OOOOa, and semiannual monitoring remains cost effective based on the revised cost estimates for well sites with total production greater than 15 boe per day, which are presented in the TSD for this final rule. Therefore, the final rule retains semiannual monitoring for well sites with total production greater than 15 boe per day.

Additionally, the EPA is neither finalizing the proposed biennial monitoring frequency at low production well sites (*i.e.,* well sites with total production at or below 15 boe per day) nor retaining the current semiannual monitoring requirement because monitoring is not cost effective at any frequency for these well sites based on the revised cost estimates. Instead, the final rule requires that a low production well site either maintain its total production at or below 15 boe per day or conduct semiannual monitoring. This requirement applies to well sites that produce at or below 15 boe per day during the first 30 days of production, as well as those sites that experience a decline in production where the total production for the well site, based on a rolling 12-month average, is at or below 15 boe per day, as demonstrated by the records required in the final rule.

Further, the EPA is finalizing the co-proposed semiannual monitoring frequency for gathering and boosting compressor stations. As explained in more detail below in section V.B.4 of the preamble, based on our comparison of the cost-effectiveness of semiannual and quarterly monitoring and consideration of other cost-related factors, we are finalizing semiannual monitoring for gathering and boosting compressor stations. This final rule does not address fugitive emissions monitoring for transmission and storage compressor stations because the Review Rule (published in the **Federal Register** of Monday, September 14, 2020) revises the source category by removing sources in the transmission and storage segment from the category. As such, the Review Rule rescinds the GHG and VOC standards for sources in the transmission and storage segment. Regardless, the TSD for this final action does include relevant updates to the model plants for the transmission and storage compressor stations.

The revised cost estimates for fugitive monitoring of well sites and gathering and boosting compressor stations rely on updates the EPA made to the model plants, including updates that address the areas of uncertainty that we identified in the October 15, 2018, proposal, as well as the revisions to the monitoring plan, recordkeeping, and reporting requirements we are making in this final rule, which reduce administrative burden without compromising our ability to determine compliance with the standards. This section describes the analyses and resulting amendments to the fugitive emissions standards in this final rule.

1. Areas of Uncertainty

In the 2016 NSPS subpart OOOOa, the EPA concluded that a fugitive emissions monitoring and repair program that includes semiannual OGI monitoring at well sites and quarterly monitoring at compressor stations and the repair of any components identified with fugitive emissions was the BSER for the collection of fugitive emissions components at well sites and compressor stations.[14] 81 FR 35826. While the EPA continued to maintain that OGI is the BSER for reducing fugitive emissions at well sites and compressor stations in the October 15, 2018, proposal, we proposed less frequent monitoring after identifying three areas of uncertainty that led to concerns that we might have overestimated the emission reductions, and, therefore, cost effectiveness, of the monitoring frequencies specified in the 2016 NSPS subpart OOOOa. We solicited comments on these three areas of uncertainty, as well as additional information, so that we could better assess the emission reductions that occur at different monitoring frequencies. Additional detailed discussion on the areas of uncertainty is available in the TSD for this final rule.[15]

In the October 15, 2018, proposal, regarding the EPA's cost analysis in the 2016 NSPS subpart OOOOa, we stated that the ''EPA identified three areas of the analysis that raise concerns regarding the emissions reductions: (1) The percent emission reduction achieved by OGI, (2) the occurrence rate of fugitive emissions at different monitoring frequencies, and (3) the initial percentage of fugitive emissions components identified with fugitive emissions.'' 83 FR 52063. Given these areas of concern, we solicited information to further refine our analysis and reduce or eliminate these uncertainties. Several commenters provided information that the EPA used to evaluate each of these areas for this final rule.

Reductions using OGI. In the October 15, 2018, proposal, the EPA maintained the estimates for emissions reductions achieved when using OGI at any type of site, which are 30 percent for biennial monitoring, 40 percent for annual monitoring, 60 percent for semiannual monitoring, and 80 percent for quarterly monitoring. As stated in the proposal, one stakeholder asserted that annual monitoring was more appropriate for compressor stations than the required quarterly monitoring. This stakeholder stated that the estimated control

[14] The rule allows the use of Method 21 as an alternative to OGI but did not conclude Method 21 was BSER because OGI was found to be more cost effective. See 81 FR 35856.

[15] See TSD located at Docket ID No. EPA–HQ–OAR–2017–0483.

efficiency for quarterly monitoring should be 90 percent (instead of 80 percent) and annual monitoring should be 80 percent (instead of 40 percent), based on the stakeholder's interpretation of results from a study conducted by the Canadian Association of Petroleum Producers (CAPP).[16] In response to this information, the EPA reviewed the CAPP report and was unable to conclude that annual OGI monitoring would achieve 80-percent emissions reductions, as stated by the stakeholder.[17] In its submission of public comments on the proposal, and in subsequent clarifying discussions, the stakeholder continued to assert that the EPA had understated the emissions reductions achieved with annual monitoring.[18] As discussed in the TSD,[19] we have reevaluated the information provided in the CAPP report and are still unable to conclude that the CAPP report demonstrates that annual OGI monitoring would achieve 80-percent emissions reductions. In brief, we concluded that the results of the CAPP report indicate that quarterly monitoring could achieve 92-percent emission reductions while annual monitoring could achieve 56-percent emission reductions based on attributing the recommended frequencies at which the components at compressor stations should be monitored to the emissions reported for those component types. However, as stated in our discussion in the TSD, these emissions reductions may also be due to factors such as improved emissions factors and not actual emissions reductions resulting from monitoring and repair.

Another commenter provided information related to the emissions reductions achieved when using OGI at the various monitoring frequencies.[20] The commenter referenced a study performed by Dr. Arvind Ravikumar as supporting the EPA's estimates of emissions reductions for annual and semiannual monitoring using OGI.[21] This study utilized the Fugitive Emissions Abatement Simulation Toolkit (FEAST) model that was developed by Stanford University to simulate emissions reductions achieved at the various monitoring frequencies. The study used information from the EPA's model plant analysis for the 2016 NSPS subpart OOOOa, including the site-level baseline emissions. Emissions reductions were estimated at 32 percent for annual monitoring, 54 percent for semiannual monitoring, and 70 percent for quarterly monitoring, which the EPA considers to be comparable to the EPA's estimated reduction efficiencies for OGI at these monitoring frequencies.

Finally, the EPA updated its analysis of emissions reductions using Method 21 for comparison to the estimated reductions using OGI. As previously stated in the proposal TSD,[22] data from the Synthetic Organic Chemicals Manufacturing Industry (SOCMI) in the 1995 Equipment Leak Protocol Document (1995 Protocol) was used to estimate the Method 21 effectiveness at the various monitoring frequencies. In the proposal TSD, we stated, ''it is not possible to correlate OGI detection capabilities with a Method 21 instrument reading, provided in ppm. However, based on the EPA's current understanding of OGI technology and the types of hydrocarbons found at oil and natural gas well sites and compressor stations, the emission reductions from an OGI monitoring and repair program likely correlate to a Method 21 monitoring and repair program with a fugitive emissions definition somewhere between 2,000 to 10,000 ppm.'' [23] We received comments asserting that the EPA inappropriately used Method 21 effectiveness estimates based on SOCMI to justify the emissions reductions for OGI. In response to these comments, the EPA updated the Method 21 effectiveness estimates using information for the oil and gas industry, as described in the TSD for this final rule.[24] The revised analysis estimates emissions reductions when using Method 21 to be 40 percent for annual monitoring, 54 percent for semiannual monitoring, and 67 percent for quarterly monitoring, when using the average reductions achieved at leak definitions of 500 ppm and 10,000 ppm. While not a direct comparison, the EPA estimates emission reductions using OGI would likely be higher because OGI will detect large emissions, such as emissions from thief hatches on controlled storage vessels, that Method 21 would otherwise not detect.

In conclusion, the EPA performed detailed analyses of the CAPP studies, the FEAST model results, and the updated Method 21 estimates to determine whether changes to the estimated effectiveness of OGI monitoring is appropriate. Based on these analyses, we conclude that the estimated effectiveness percentages of OGI monitoring at the various frequencies are appropriate and do not need adjustment.

Leak occurrence rates. The second uncertainty identified in the October 15, 2018, proposal relates to the occurrence rate of fugitive emissions, or the percentage of components identified with fugitive emissions during each survey. In the proposal, the EPA stated, ''because the model plants assume that the percentage of components found with fugitive emissions is the same regardless of the monitoring frequency, we acknowledge that we may have overestimated the total number of fugitive emissions components identified during each of the more frequent monitoring cycles.'' 83 FR 52064. There are numerous ways the number of leaking components could impact the cost effectiveness of monitoring, including (1) the amount of baseline emissions, (2) the potential emission reductions, and (3) the number of repairs required.

In the 2016 analysis, the EPA assumed that each monitoring survey at a well site would identify four components with fugitive emissions. That is, when a site is monitored annually, we estimated four total components leaking for that year, but if that same site were monitored semiannually, we estimated eight total components leaking for that year. However, we have found that a constant leak occurrence rate is not reflected in our analysis of Method 21 monitoring, the information provided through comments on the proposal, or a review of the annual compliance reports submitted to the EPA for the NSPS subpart OOOOa. Rather, the information demonstrates that occurrence rates differ based on monitoring frequency. For example, the information we reviewed in the annual compliance reports for well site fugitive emissions components demonstrated that, on average, three components were identified as leaking where only one survey had taken place in a 12-month period, and two components were identified as leaking, per survey, where more than one survey had occurred in

[16] CAPP, ''Update of Fugitive Equipment Leak Emission Factors,'' prepared for CAPP by Clearstone Engineering, Ltd., February 2014.

[17] See memorandum, ''EPA Analysis of Fugitive Emissions Data Provided by Interstate Natural Gas Association of America (INGAA),'' located at Docket ID Item No. EPA–HQ–OAR–2017–0483–0060. August 21, 2018.

[18] See Docket ID Item No. EPA–HQ–OAR–2017–0483–1002 and Memorandum for the April 30, 2019 Meeting with INGAA, located at Docket ID No. EPA–HQ–OAR–2017–0483.

[19] See TSD, section 2.4.1.1 for more details at Docket ID No. EPA–HQ–OAR–2017–0483.

[20] See Docket ID Item No. EPA–HQ–OAR–2017–0483–2041.

[21] See Appendix D to Docket ID Item No. EPA–HQ–OAR–2017–0483–2041.

[22] See Docket ID Item No. EPA–HQ–OAR–2017–0483–0040.

[23] See Docket ID Item No. EPA–HQ–OAR–2017–0483–0040, at page 25.

[24] See TSD at Docket ID No. EPA–HQ–OAR–2017–0483.

a 12-month period.[25] These values are similar to those provided by two commenters that provided detailed information on the number of components identified with fugitive emissions at different monitoring frequencies.[26] Therefore, we updated the well site model plant analysis to include an average of three components per annual survey and two components per semiannual survey (for a total of four repairs annually).[27]

In the 2016 analysis, the EPA assigned each type of compressor station (*i.e.,* gathering and boosting, transmission, and storage) a specific leak occurrence rate. While annual compliance reports were submitted for compressor stations complying with NSPS subpart OOOOa, it was not possible to determine which stations were which type. However, for gathering and boosting compressor stations, detailed information was provided by GPA Midstream.[28] While the number of reported leaks varied widely in the dataset, the EPA's analysis of the data demonstrated that, on average, 11 components were identified as leaking during a 12-month period, with monitoring frequencies ranging from monthly to annually.[29] Therefore, we assumed that a total of 11 components, on average, would be identified as leaking over the course of a full year's worth of monitoring, regardless of monitoring frequency. That is, we assumed that if monitoring occurs semiannually, on average, 11 components will be leaking over the course of the two surveys in that year. This estimate takes into account the reported variation in the number of components identified as leaking during each survey. For example, a gathering and boosting compressor station that is monitoring quarterly may identify the following number of components as leaking: Three components in Quarter 1; two components in Quarter 2; four components in Quarter 3; and two components in Quarter 4. If that same gathering and boosting compressor station were monitored annually, then all 11 components would be identified during the one annual survey. This is different than the assumption used in the 2016 NSPS subpart OOOOa. Utilizing the estimate of 11 components identified as leaking over the course of 1 year provides an annual estimate of the repair costs for gathering and boosting compressor stations which is independent of the monitoring survey costs. That is, on average, the same number of repairs are made in a single year, regardless of the frequency of surveys, which helps account for the variability presented in the dataset.

In summary, the EPA is no longer using a linear function for occurrence rates as we did in the proposal or the 2016 NSPS subpart OOOOa. Instead, we have based occurrence rates on available information that is specific to fugitive emissions monitoring frequencies for each type of facility. Specifically, we estimate a total of two repairs (leaking components) at the annual monitoring frequency and three repairs at the semiannual monitoring frequency for well sites. For gathering and boosting compressor stations we estimate that, on average, 11 repairs are necessary over the course of a year. This updated analysis more directly reflects the reality that leak occurrence rates are not linear between frequencies and more appropriately estimates the number of repairs (and, thus, emission reductions and costs) at more frequent monitoring. Thus, the EPA no longer considers leak occurrence rates to raise uncertainties with the analysis or to overestimate emissions.

Initial leak rate. The final uncertainty raised in the October 15, 2018, proposal was the initial percentage of components identified with fugitive emissions (''initial leak rate''). While the EPA did not use an initial leak rate in our estimate of the baseline emissions, one commenter noted that initial leak rate should be considered a key element for understanding potential baseline emissions. The commenter stated its belief that the emissions factor the EPA used to estimate baseline emissions was calculated using an initial leak rate that was too high, thus, biasing the baseline emissions (and the resulting emission reductions) high.[30]

In the 2016 NSPS subpart OOOOa TSD, the EPA stated incorrectly that the model plant analysis assumed an initial leak rate of 1.18 percent.[31] One commenter pointed out that this initial leak rate, which was also cited in the October 15, 2018, proposal, was not the actual estimate used for the model plant analysis. The commenter is correct on this point. The uncontrolled emissions factors for non-thief hatch fugitive emission components the EPA used to estimate model plant emissions are based on Table 2–4 of the Protocol for Equipment Leak Emission Estimates (''Protocol Document'').[32] While the initial leak rates that are inherent in these emissions factors are not specifically stated in the Protocol Document, the commenter performed a back-calculation of the fraction of leaking components using Table 5–7 of the Protocol Document and the weighted leak fraction for all components using the number of each component per model plant. That result, with which the EPA agrees, shows that when using Method 21 and a leak definition of 500 ppm, the estimated initial leak rate is 2.5%, and when using Method 21 and a leak definition of 10,000 ppm, the estimated initial leak rate is 1.65 percent.[33] However, the initial leak rate is only one contributing factor to baseline emissions. Another contributing factor is the magnitude of emissions.

While several commenters [34] provided information on the number or percentage of components identified with fugitive emissions, no commenters provided component-level information on the magnitude of those emissions.[35] In June 2019, a study was published in Elementa that examined fugitive emissions from 67 oil and natural gas well sites and gathering and boosting compressor stations in the Western U.S.[36] As discussed in the TSD, the study included quantification of fugitive emissions from components located at well sites and gathering and boosting compressor stations. The EPA evaluated the measured fugitive emissions from that study for central production, well production, and well site facilities, as defined by the study. We then evaluated the average emissions across those three site types to compare those emissions to

[25] See TSD located at Docket ID No. EPA–HQ–OAR–2017–0483.

[26] See Docket ID Item Nos. EPA–HQ–OAR–2017–0483–0801 and EPA–HQ–OAR–2017–0483–2041.

[27] The 2016 model plant analysis included an evaluation of quarterly monitoring for well sites. Because semiannual monitoring is required, it was not possible to determine the quarterly occurrence rate for well sites using this information. See TSD for additional analysis.

[28] See Docket ID Item No. EPA–HQ–OAR–2017–0483–1261.

[29] See TSD located at Docket ID No. EPA–HQ–OAR–2017–0483.

[30] See Docket ID Item No. EPA–HQ–OAR–2017–0483–0801.

[31] See Docket ID Item No. EPA–HQ–OAR–2010–0505–7631.

[32] See U.S. EPA, ''1995 Protocol for Equipment Leak Emission Estimates Emission Standards'' located at Docket ID Item No. EPA–HQ–OAR–2017–0483–0002.

[33] See memorandum, ''Summary of Data Received on the October 15, 2018 Proposed Amendments to 40 CFR part 60, subpart OOOOa Related to Model Plant Fugitive Emissions.'' February 10, 2020.

[34] See, for example, Docket ID Item Nos. EPA–HQ–OAR–2017–0483–0801, EPA–HQ–OAR–2017–0483–1261, and EPA–HQ–OAR–2017–0483–2041.

[35] See memorandum, ''Summary of Data Received on the October 15, 2018 Proposed Amendments to 40 CFR part 60, subpart OOOOa Related to Model Plant Fugitive Emissions.'' February 10, 2020.

[36] See Pasci, A.P., Ferrara, T., Schwan, K., Tupper, P., Lev-On, M., Smith, R., and Ritter, K., 2019. ''Equipment Leak Detection and Quantification at 67 Oil and Gas Sites in the Western United States.'' Elem Sci Anth, 7(1), p.29 located at *http://doi.org/10.1525/elementa.368.*

the estimated emissions using the average emissions factors from the EPA Protocol Document. The average well site emissions measured in the study were comparable to the model plant well site emissions. Therefore, the EPA determined that the use of the emissions factors from the 1995 Protocol Document was still appropriate and has maintained use of these average emissions factors in the model plant analyses supporting this final rule.

In conclusion, we identified three areas of potential uncertainty in the October 15, 2018, proposal: (1) The effectiveness of OGI at the various frequencies, (2) the leak occurrence rate for each survey, and (3) the initial leak rate. The EPA was concerned that we might have overestimated the emission reductions from the monitoring frequencies in the 2016 NSPS subpart OOOOa due to these three areas of uncertainties. However, after evaluating the data provided by commenters and making the appropriate revisions to our model plant analysis, the EPA no longer believes that these three areas create uncertainty or resulted in an overestimation of emissions reductions.

2. Recordkeeping, Reporting, and Other Administrative Burden Associated With the Fugitive Emissions Program

In addition to proposing reduced monitoring frequencies, the EPA proposed amending the monitoring plan requirements in the 2016 NSPS subpart OOOOa. Specifically, we proposed these amendments to address concerns that the requirements, such as the site map and observation path, resulted in significant costs that increase over time due to the increase in the number of facilities subject to the requirements each year. The EPA proposed allowing alternatives to the site map and observation path that would also ensure that all fugitive components at a site are monitored. 83 FR 52078 and 9. The EPA received comments expressing concern that, in addition to the costs associated with the development and necessary updates of the monitoring plan, the EPA had underestimated the administrative burden associated with the extensive recordkeeping and reporting requirements of the fugitive emissions standards in the 2016 NSPS subpart OOOOa. These commenters stated that this burden represents the largest cost of the fugitive emissions program in the 2016 NSPS subpart OOOOa.[37] In the October 15, 2018, proposed rulemaking, the EPA proposed to streamline certain recordkeeping and reporting requirements in the 2016 NSPS subpart OOOOa to reduce burden on the industry, including the fugitive emissions recordkeeping and reporting. 83 FR 52059. In response to these comments, the EPA re-evaluated the fugitive emissions program, with a focus on identifying areas to reduce unnecessary administrative burden and provide flexibility for future innovation, while retaining sufficient recordkeeping and reporting requirements to assure that affected facilities are complying with the standards. After concluding this re-evaluation, we found that certain requirements were unnecessary and burdensome.

First, we examined the commenters' assertion and supporting information that the EPA underestimated the recordkeeping and reporting costs in both the 2016 NSPS subpart OOOOa and the October 15, 2018, proposal. To better understand the commenters' statements regarding the recordkeeping and reporting costs associated with the 2016 NSPS subpart OOOOa, we reviewed the specific recordkeeping and reporting requirements for the fugitive emissions program, including the monitoring plan. Based on this review, we agree with the commenters that the recordkeeping and reporting burden was underestimated in both the 2016 NSPS subpart OOOOa and the October 15, 2018, proposal, as described below.

In the October 15, 2018, proposal, we had proposed reducing certain monitoring frequencies. While we updated portions of the model plant analysis for fugitive emissions to reflect these proposed changes, we did not make specific changes related to recordkeeping and reporting costs. As shown in the proposal TSD,[38] we estimated that the development of a monitoring plan was a one-time cost of $3,672 per company-defined area, which is estimated as consisting of 22 well sites or seven gathering and boosting compressor stations. We estimated reporting costs to be at $245 per site per year.

Second, we reevaluated the cost burden of the recordkeeping and reporting requirements associated with the fugitive emissions standards in the 2016 NSPS subpart OOOOa prior to considering any additional changes to those standards that might further reduce the cost burden. This step was necessary to provide a correct baseline for comparison when evaluating the burden reductions associated with potential changes to the standards.

Before considering the information provided in the comments, we removed certain line items from the previous analysis as described. We removed the initial and subsequent planning activities because these items were not clearly representative of actual recordkeeping activities that are associated with the fugitive emissions requirements of the rule (*e.g.,* records management systems, tracking components, data review, etc.). We also removed the cost associated with notification of initial compliance status because such notification is not required under the 2016 NSPS subpart OOOOa. Next, we considered the comments and information received on our estimate of the cost to develop a monitoring plan under the 2016 NSPS subpart OOOOa. One commenter provided information on the range of costs that have been incurred by owners and operators to develop a monitoring plan since the rule has been in place.[39] These estimated costs range from $5,600 to $8,800, which is more than our estimate of $3,672. In examining the information provided by the commenter in further detail, we note that hourly rates are higher than the standard labor rate used in EPA's calculations, which would attribute to the difference in costs. Next, commenters dispute our assumption that the monitoring plan is a one-time cost for the company. Several commenters stated while most of the monitoring plan is associated with a one-time cost, the required site map and observation path require frequent updates as the equipment at the site changes. One of these commenters provided an estimate of the cost to develop the initial site map and observation path for an individual site, and the cost of updating these items for each monitoring survey.[40] This information provided estimates that companies have already spent approximately $650 developing the individual site map and observation path for each site and an additional $150 updating these items for each monitoring survey. Based on this information, we agree it is appropriate to account for the necessary updates for

[37] See Docket ID Item No. EPA–HQ–OAR–2017–0483–0016.

[38] See TSD at Docket ID Item No. EPA–HQ–OAR–2017–0483–0040.

[39] See Docket ID No. EPA–HQ–OAR–2017–0483; EPA's ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration; Proposed Rule''; 83 FR 52056 (October 15, 2018). Dated May 22, 2019, located at Docket ID No. EPA–HQ–OAR–2017–0483.

[40] See Docket ID No. EPA–HQ–OAR–2017–0483; EPA's ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration; Proposed Rule''; 83 FR 52056 (October 15, 2018). Dated May 22, 2019, located at Docket ID No. EPA–HQ–OAR–2017–0483.

the site map and observation path when estimating the cost burden of the rule. Therefore, we split the monitoring plan costs into three items in our model plant analysis: (1) Develop company-wide fugitive emissions monitoring plan, (2) develop site-specific fugitive monitoring plan (*i.e.,* site map and observation path), and (3) management of change (site map and observation path). Additionally, we applied hourly rates, based on information provided by the commenter, to estimate costs instead of using the flat cost values provided. The updated estimates associated with developing a monitoring plan for well sites under the existing standards are $2,448 to develop the general company-wide monitoring plan (assumes 22 well sites), $400 to develop the site map and observation path for each site, and $184 to update the individual site map and observation path annually (based on semiannual monitoring). This would result in a total cost for development of the monitoring plan for the 22 well site company-defined area of $15,296, including updates to the site map and observation path at the semiannual surveys conducted that first year. For gathering and boosting compressor stations, we estimate it costs $1,530 to develop a company-wide monitoring plan (assumes seven stations per plan), $400 to develop the site map and observation path for each site, and $367 to update the individual site map and observation path annually (based on quarterly monitoring). This would result in a total cost of $6,899 for development of the monitoring plan for the seven gathering and boosting compressor station company-defined area, including updates to the site map and observation path at the quarterly surveys conducted that first year. Based on available information, we believe these costs are representative of the costs to develop and maintain the monitoring plan as required in the 2016 NSPS subpart OOOOa.

We then examined the recordkeeping costs associated with the fugitive emissions requirements. As stated above, we were unable to locate clearly defined estimates for recordkeeping costs for the 2016 NSPS subpart OOOOa, therefore, all costs are new in our baseline estimate of the actual cost of the existing standards and are based on information received from commenters and previous information collected by the Agency for similar programs. There are extensive records required for each survey that is performed, regardless of the frequency; therefore, we recognize that appropriate data management is critical to ensuring compliance with the standards. As explained in the TSD for this final rule,[41] we evaluated costs for the set-up for a database system, which ranged from commercially available options to customized systems. Because there are commercial systems currently available that allow owners and operators to maintain records in compliance with the standards, we did not find it appropriate to apply customized system costs to determine an average or range of costs. Therefore, our initial database set-up fee is estimated as $18,607 for 22 well sites and seven gathering and boosting compressor stations. In addition to this initial set-up fee, we recognize that there are annual licensing fees that include technical support and updates to software. Therefore, we have incorporated an ongoing annual fee of approximately $470. Finally, there is recordkeeping associated with tracking observed fugitive emissions and repairs, such as scheduling repairs and quality control of the data. Based on information provided by commenters,[42] we estimate additional recordkeeping costs at $430 for well sites and $860 for gathering and boosting compressor stations.

Finally, we evaluated the current estimate for reporting costs associated with the 2016 NSPS subpart OOOOa. One commenter asserted they spent over 500 hours reporting information through the Compliance and Emissions Data Reporting Interface (CEDRI) for their sources.[43] We examined the information reported to CEDRI for this commenter and concluded they have reported information for approximately 100 well sites, which would equate to 5 hours per site. This is comparable to our estimate of 4 hours per well site; therefore, we did not update the cost estimate for reporting associated with the 2016 NSPS subpart OOOOa.

In summary, we updated the cost burden estimates for recordkeeping based on the 2016 NSPS subpart OOOOa. As updated, the annualized recordkeeping and reporting costs for the existing rule, on a per site basis, are approximately $1,500 per well site and $2,500 per gathering and boosting compressor station. These costs represent the baseline from which any changes to the cost burden for reporting and recordkeeping requirements in this final rule are compared. It is important to note that while these costs represent the costs for each individual site, the EPA estimates that currently there are over 40,000 well sites and 1,250 compressor stations currently subject to the fugitive emissions requirements in the 2016 NSPS subpart OOOOa. When multiplied, the total annualized costs to the industry is estimated to exceed $60 million per year.

After updating the recordkeeping and reporting costs for the existing requirements, we evaluated requests by commenters recommending specific changes to those requirements. Several commenters requested removal of or amendments to specific line items. These included items such as the site map and observation path requirement in the monitoring plan, records related to the date and repair method for each repair attempt, and name of the operator performing the survey. After further review of the specific requirements, for the reasons explained below, we agree with the commenters that some of the items are not critical or are redundant for demonstrating compliance and, therefore, are an unnecessary burden.

We are amending the monitoring plan by removing the requirement for a site map and observation path when OGI is used to perform fugitive emissions surveys. This requirement was in place to ensure that all fugitive emissions components could and would be imaged during each survey. As explained in the TSD,[44] we agree with the commenters that a site map and observation path are only one way to ensure all components are imaged. We are replacing the specified site map and observation path with a requirement to include procedures to ensure that all fugitive emissions components are monitored during each survey in the monitoring plan. These procedures may include a site map and observation path, an inventory, or narrative of the location of each fugitive emissions component, but may also include other procedures not listed here. These company-defined procedures are consistent with other requirements for procedures in the monitoring plan, such as the requirement for procedures for determining the maximum viewing distance and maintaining this viewing distance during a survey. As previously stated, we had not accurately accounted for the ongoing cost of updating the site map and observation path as changes

[41] See TSD at Docket ID No. EPA–HQ–OAR–2017–0483.

[42] See Re: Docket ID No. EPA–HQ–OAR–2017–0483; EPA's ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration; Proposed Rule''; 83 FR 52056 (October 15, 2018). Dated May 22, 2019, located at Docket ID No. EPA–HQ–OAR–2017–0483. See memorandum for May 1, 2019 meeting with GPA Midstream located at Docket ID No. EPA–HQ–OAR–2017–0483.

[43] See Docket ID Item No. EPA–HQ–OAR–2017–0483–0757.

[44] See TSD at Docket ID No. EPA–HQ–OAR–2017–0483.

occur at the site. Based on information provided by one commenter, we estimate this amendment will save each site $580 with the semiannual monitoring frequency. These cost reductions are based on an initial cost of $400 to develop the site map and observation path, plus $180 to update the site map or observation path each year, based on a semiannual monitoring frequency.

We are not finalizing the proposed recordkeeping requirement to keep records of each repair attempt. Instead, the final rule requires maintaining a record only for the first attempt at repair and the completion of repair. Other interim repair attempts are not necessary for demonstrating compliance with the repair requirements. Additionally, we are removing the requirement to maintain records of the number and type of components not repaired during the monitoring survey. The 2016 NSPS subpart OOOOa required maintaining a record of the number and type of components found with fugitive emissions that were not repaired during the monitoring survey. After further review, this information can be derived from, and is, therefore, redundant to, other records of the survey date and repair dates required for all fugitive emissions components. While it is difficult to quantify the reduction in cost burden of the removal of these records, we have estimated a reduction in cost of 25 percent, or $107 per site per year as discussed in the TSD.

We are also amending the reporting requirements to streamline reporting based on comments received and further reconsideration of what information is essential to demonstrate compliance with the standards. First, as we are finalizing the electronic reporting form for the annual report required by 40 CFR 60.5420a(b) concurrently with this action, we are updating the CEDRI reporting template to reflect the streamlined reporting requirements in this final action and ease review of the information contained within the form. Specifically, for reporting compliance with the fugitive emissions requirements, we have created dropdown menus for the operator to select the type of site for which they are reporting (*i.e.,* well site or compressor station), to indicate whether the well site changed status to a wellhead-only well site during the reporting period, and identify any approved alternative fugitive emissions standard that was used during the reporting period for the site. Second, we are removing specific items from the annual report as listed in section IV.I.3 of this preamble. We are removing the requirement to report the name or unique ID of the operator performing the survey; however, this information must be maintained in the record, similar to the LDAR requirements for onshore natural gas processing plants. We are removing the requirement to report the number and type of difficult-to-monitor and unsafe-to-monitor components that were monitored during the specified survey. This information is required to be kept in the record, and the type and number of these components would already be included in the reported number and type of components found with fugitive emissions during the survey. The date of successful repair is being removed from the report because we already require owners and operators to report the number and type of fugitive emissions not repaired on time. The date of successful repair will be maintained in the record. Finally, the type of instrument used for the resurvey is being removed from the report because the rule allows either OGI or Method 21 (analyzer or a soap bubbles test). The information is required to be kept in the record. Similar to the recordkeeping changes identified in the previous paragraph, it is difficult to estimate the reduced cost burden of each of these individual items. That said, as shown in the TSD, we have estimated a burden reduction of 25 percent, or $61 per site per annual report.

In summary, the amendments to the recordkeeping and reporting requirements in this final rule will reduce the recordkeeping and reporting burden for NSPS subpart OOOOa. The estimated annualized recordkeeping and reporting costs for this final rule, on a per site basis, are approximately $1,100 per well site and $1,750 per gathering and boosting compressor station. This results in an annualized burden reduction of approximately 27 percent for well sites and 30 percent for gathering and boosting compressor stations.[45]

3. Additional Updates to the Model Plants

We also received information from commenters that suggested additional updates beyond those already discussed above. These included the major equipment counts and survey costs. A detailed discussion of these updates, which we agree are necessary, is provided in the TSD.[46] A summary of these updates is provided below.

Well sites. In the October 15, 2018, proposal, we maintained the assumed flat contractor fee of $600 per survey. However, information from commenters suggested this may be an overestimate of survey costs if an hourly rate were used. To examine this comment, we analyzed the CEDRI reports, and evaluated the survey times that were reported. Based on this information, we estimated it takes operators 3.4 hours to complete a survey at a well site, including the travel time to and from the well site. This is based on an average survey time of approximately 1.4 hours. The travel time considers travel between sites and the shared travel of mobilizing a monitoring operator. We applied an hourly rate of $134 based on the Regulatory Analysis performed by the Colorado Department of Public Health and Environment in support of Colorado's Regulation 7.[47] We believe this more accurately reflects the costs of performing the survey than the previously assumed flat rate of $600.

Low production well sites. The low production well site model plants (*i.e.,* well sites with total production at or below 15 boe per day) were updated after further review of the Fort Worth Study, updates to the Greenhouse Gas Inventory (GHGI), and based on comments received. First, the counts of wellheads, separators, meters/piping, and dehydrators were recalculated after removing well sites that listed no production on the day prior to emissions measurements during the Fort Worth Study. This resulted in a decrease in the number of separators and meters/piping for the low production gas well pad. The scaling factors were also updated based on these revisions and applied to low production oil well pads and low production associated gas well pads. Further discussion on these changes are in the TSD. Like the well sites discussed above, we maintained the estimate of one controlled storage vessel per low production well site. One commenter provided some preliminary information regarding component counts, specific to valves and storage vessels, but also stated in their comments that the information was not representative.[48] Therefore, as discussed in the TSD, it was not appropriate to revise the model plants using information this commenter provided. We also

[45] See TSD for additional information on the estimated cost burden at the individual site level at Docket ID No. EPA–HQ–OAR–2017–0483.

[46] See TSD at Docket ID No. EPA–HQ–OAR–2017–0483.

[47] Colorado Department of Public Health and Environment, ''Regulatory Analysis for Proposed Revisions to Colorado Air Quality Control Commission Regulation Numbers 3, 6, and 7'' (5 CCR 1001–5, 5 CCR 1001–8, and CCR 1001–9), February 2014.

[48] See Docket ID Item No. EPA–HQ–OAR–2017–0483–1006.

performed an analysis of the survey time and found that on average, the surveys for low production well sites were approximately 30 minutes. After accounting for travel time, we estimate that each survey of a low production well site takes 2.4 hours. We applied the same hourly rate of $134 to estimate the total cost of each survey.

Gathering and boosting compressor stations. Information of average equipment counts were provided by GPA Midstream for gathering and boosting compressor stations.[49] We updated the model plant estimate to use this information. Specifically, we revised the estimated number of separators from 11 to five, meter/piping from seven to six, gathering compressors from five to three, in-line heaters from seven to one, and dehydrators from five to one, which reduces the baseline emissions estimated for the compressor station. We maintained the cost for the survey of $2,300 because the commenter indicated this was appropriate based on implementation of the rule.

4. Cost Effectiveness of Fugitive Emissions Requirements

With the revisions discussed in sections V.B.1 through 3 of this preamble incorporated in the model plants, we reexamined the costs and emission reductions for various monitoring frequencies to determine the updated costs of control. In evaluating the costs for this final rule, we also reexamined the decisions made in the 2016 NSPS subpart OOOOa for comparison. In the 2016 NSPS subpart OOOOa, we evaluated the controls under different approaches, namely a single pollutant approach and multipollutant approach.[50] Further, we stated that a frequency is considered cost effective if the cost of control for any one scenario of methane (without consideration of VOC), VOC (without consideration of methane), or the combination of both pollutants is cost effective.[51] That is, if the cost of control for reducing VOC, where all costs are attributed to VOC control and zero to methane control, is cost effective, then that frequency is cost effective regardless of the methane-only or multipollutant costs.

In the Review Rule, finalized in the **Federal Register** of Monday, September 14, 2020, we are rescinding the methane standards for NSPS subpart OOOOa. Therefore, in this final rule, we examined the cost effectiveness for the control of VOC emissions only. For each frequency evaluated in this final rule, we examined the total cost effectiveness of each monitoring frequency (*i.e.,* the cost of control for each frequency from a baseline of no monitoring). This is consistent with how costs were examined in the 2016 NSPS subpart OOOOa. For the reason explained in the preamble to the October 15, 2018, proposal, in addition to evaluating the total cost effectiveness of the different monitoring frequencies, this final rule also considers incremental cost (*i.e.,* the additional cost to achieve the next increment of emission reduction) to be an appropriate tool for assessing the effects of different stringency levels of control costs.[52] 83 FR 52070. It is important to note that the 2016 NSPS subpart OOOOa analysis did not present the incremental costs between each of the monitoring frequencies evaluated. The TSD supporting this final rule presents the cost of control for annual, semiannual, and quarterly monitoring frequencies for well sites producing greater than 15 boe per day and compressor stations, and biennial, annual, and semiannual monitoring frequencies for low production well sites.

When examining the costs of each monitoring frequency, we recognized that a significant percentage of the costs are independent of the monitoring frequency. That is, when annualized, the recordkeeping and reporting costs remain unchanged as monitoring frequencies increase. For example, the annualized cost of semiannual monitoring is approximately 20 percent higher than the annualized cost of annual monitoring at well sites. However, the cost effectiveness of the annual monitoring is a higher $/ton reduced because semiannual monitoring results in approximately 50 percent more emissions reductions than annual monitoring. Therefore, while more frequent monitoring does increase the costs of surveys for the year, the bulk of the costs are realized regardless of monitoring frequency. In other words, whereas we assumed during the proposal that reduced monitoring frequencies would lead to large cost savings, the analyses we performed for this final rule demonstrate that monitoring frequency is not the most significant factor in the overall cost of the fugitive emissions requirements. Below we present the costs of control for the monitoring frequencies at the model plants for well sites, low production well sites, and compressor stations.

Table 3 presents the costs of control for VOC emissions at the monitoring frequencies evaluated in this final rule and compares those costs to the costs presented for the 2016 NSPS subpart OOOOa. With the updates to the model plants discussed in section V.B.1 through 3 of this preamble, the EPA estimates that the semiannual monitoring currently required by the 2016 NSPS subpart OOOOa for well sites has a cost-effectiveness value of $4,324/ton of VOC emissions reduced. This value is $1,135/ton less than was estimated for semiannual monitoring in 2016, after adjusting for inflation. Therefore, we have determined that semiannual monitoring remains cost effective for well sites producing greater than 15 boe per day. We also considered the incremental cost effectiveness of semiannual monitoring compared to annual monitoring. This analysis showed that it cost $2,666/ton of additional VOC emissions reduced between the annual and semiannual monitoring frequencies. This cost is very reasonable and, therefore, further supports retaining semiannual monitoring. Finally, the EPA notes that, while we did not propose or take comment on quarterly monitoring for well sites, this monitoring frequency results in a total cost of control of $4,725/ton of VOC emissions reduced, which is also less than the inflation-adjusted cost-effectiveness value for quarterly monitoring that was calculated in 2016. However, the incremental cost to reduce additional emissions by going from semiannual monitoring to quarterly monitoring is $5,927/ton, which is a value that is higher than the EPA has previously found to be cost effective in the past.[53]

[49] See Docket Item ID No. EPA–HQ–OAR–2017–0483–1261.

[50] See 80 FR 56616. Under the single pollutant approach, we assign all costs to the reduction of one pollutant and zero costs for all other pollutants simultaneously reduced. Under the multipollutant approach, we allocate the annualized costs across the pollutant reductions addressed by the control option in proportion to the relative percentage reduction of each pollutant controlled. For purposes of the multipollutant approach, we assume that emissions of methane and VOC are controlled at the same time, therefore, half of the cost is apportioned to the methane emission reductions and half of the cost is apportioned to VOC emission reductions. In this evaluation, we examined both approaches across the range of identified monitoring frequencies, annual, semiannual, and quarterly.

[51] See 80 FR 56617.

[52] See also, ''Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemical Manufacturing Industry (SOCMI); Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries''; 72 FR 64860, 64864 (''2007 NSPS subparts VV and VVa'') (in its BSER analysis, the EPA evaluated the additional cost and emission reduction from lowering the leak definition for valves and determined that the additional emission reduction for SOCMI, at $5,700/ton of VOC, is not cost effective.)

[53] See 2007 NSPS subparts VV and VVa, 72 FR 64864, cited in the 2016 NSPS subpart OOOOa final rule, 80 FR 56636. See TSD for additional analysis

TABLE 3—COST-EFFECTIVENESS OF CONTROL FOR WELL SITES SUBJECT TO FUGITIVE EMISSIONS STANDARDS UNDER SUBPART OOOOA OF 40 CFR PART 60

Monitoring frequency	Cost effectiveness ($/ton VOC)		
	2016 TSD total cost effectiveness [1]	2020 TSD total cost effectiveness [2]	2020 TSD incremental cost effectiveness
Annual	$4,723	$5,153	
Semiannual	5,459	4,324	2,666
Quarterly	7,559	4,725	5,927

[1] Values from the 2016 TSD have been adjusted for inflation for comparison purposes.

[2] As discussed in section V.B of this preamble, the EPA received comments that our original 2016 estimates were low, especially for recordkeeping and reporting burden. The 2020 estimates include adjustments to the 2016 estimates based on this information (which is higher than the 2016 TSD) plus include streamlined recordkeeping and reporting as well as other updates. In addition, the revised analysis found that the majority of the costs of the fugitive requirements are annual costs and do not vary with the monitoring frequency. That is, the recordkeeping and reporting burden remain consistent regardless of the monitoring frequency and the cost of each survey is not directly proportional to the incremental emissions reductions achieved at more frequent surveys. This is further explained in section V.B.2 of this preamble. Hence, Table 3 shows an increase in cost effectiveness for the annual monitoring frequency, but a decrease in the cost effectiveness for the semiannual and quarterly cost effectiveness from the 2020 TSD. In contrast, the 2016 values presented here are directly from the 2016 TSD and have not been adjusted based on our new analysis of what the 2016 rule cost.

As shown in the EPA's revised model plant analysis in the TSD for this final rule, and consistent with the October 15, 2018, proposal, there is sufficient evidence that low production well sites are different than well sites with higher production and, therefore, warrant a separate evaluation of the cost of control. The EPA did not include a separate analysis of low production well sites in the 2016 NSPS subpart OOOOa. Therefore, all costs presented above for well sites from the 2016 analysis also would apply to low production well sites. The EPA proposed biennial monitoring of low production well sites (*i.e.,* well sites with total production at or below 15 boe per day). Based on the revised cost analysis, the EPA estimates that the proposed biennial monitoring frequency has a cost effectiveness of $6,061/ton of VOC emissions reduced. In addition, we estimate that annual monitoring would cost $7,577/ton VOC, and semiannual monitoring currently required by the 2016 NSPS subpart OOOOa has a cost of $6,116/ton of VOC emissions reduced. All of these values are higher than the inflation-adjusted value of $5,459/ton VOC that was estimated for semiannual monitoring at well sites in 2016. Further, all of these costs are higher than a value the EPA has previously stated is not cost effective.[54] Therefore, we have determined that none of the monitoring frequencies are cost effective for low production well sites. Table 4 provides a summary of the costs of control for low production well sites.

TABLE 4—COST-EFFECTIVENESS OF CONTROL FOR LOW PRODUCTION WELL SITES SUBJECT TO FUGITIVE EMISSIONS STANDARDS UNDER SUBPART OOOOA OF 40 CFR PART 60

Monitoring frequency	Cost effectiveness ($/ton VOC)		
	2016 TSD total cost effectiveness [1]	2020 TSD total cost effectiveness [2]	2020 TSD incremental cost effectiveness
Biennial [3]	N/A	$6,061	
Annual	$4,723	7,577	$12,125
Semiannual	5,459	6,116	3,192

[1] Values from the 2016 TSD have been adjusted for inflation for comparison purposes.

[2] As discussed in section V.B of this preamble, the EPA received comments that our original 2016 estimates were low, especially for recordkeeping and reporting burden. The 2020 estimates include adjustments to the 2016 estimates based on this information (which is higher than the 2016 TSD) plus include streamlined recordkeeping and reporting as well as other updates. In addition, the revised analysis found that the majority of the costs of the fugitive requirements are annual costs and do not vary with the monitoring frequency. That is, the recordkeeping and reporting burden remain consistent regardless of the monitoring frequency and the cost of each survey is not directly proportional to the incremental emissions reductions achieved at more frequent surveys. This is further explained in section V.B.2 of this preamble. Further, low production well site model plants were not developed as part of the 2016 rulemaking. Therefore, the 2016 values presented here were for all well sites, without consideration of production. Hence, Table 4 shows an increase in cost effectiveness for the monitoring frequencies presented. In contrast, the 2016 values presented here are directly from the 2016 TSD and have not been adjusted based on our new analysis of what the 2016 rule cost.

[3] Biennial monitoring was not evaluated in 2016, therefore, no cost effectiveness is presented in Table 4.

Further, while this final rule does not have to consider the costs of controlling methane emissions, the EPA did evaluate those costs. The costs for all of the monitoring frequencies evaluated for low production well sites are greater

[54] See 2007 NSPS subparts VV and VVa, 72 FR 64864, cited in the 2016 NSPS subpart OOOOa final rule, 80 FR 56636. See TSD for additional analysis and cost information, located at Docket ID No. EPA–HQ–OAR–2017–0483.

and cost information, located at Docket ID No. EPA–HQ–OAR–2017–0483.

than the highest value for methane that the EPA determined to be reasonable in the 2016 NSPS subpart OOOOa for both methane only and under the multipollutant approach.[55] In the 2015 proposal for NSPS subpart OOOOa, the EPA stated that a cost of control of $738 per ton of methane reduced did not appear excessive when all costs are assigned to methane reduction and zero to VOC reduction. 80 FR 56624. Based on the revised analysis, the costs of control of methane emissions under the single pollutant approach for low production well sites are more than double this value of $738 per ton at all of the monitoring frequencies evaluated. This value is also exceeded under a multipollutant approach where methane reduction only assumes half the cost, as explained in the TSD.[56] Therefore, even if we had not rescinded the methane standards in the Review Rule, we would still conclude that fugitive emissions monitoring, at any of the frequencies evaluated, is not cost effective for low production well sites.

While we are concluding that fugitive emissions monitoring is not cost effective for low production well sites, production at these well sites could potentially increase to greater than 15 boe per day, rendering monitoring to be cost effective. For example, a new well may be drilled at a well site, or the existing wells may be refractured to increase the production levels. When these actions occur, the final rule requires a new 30-day calculation of the total well site production. If the total production remains at or below 15 boe per day, no monitoring is required as long as the owner or operator continues to maintain the production at these low levels. However, if the total production following one of these actions has increased to greater than 15 boe per day, the owner or operator must begin monitoring for fugitive emissions within 90 days of the startup of production following such action, the same as the requirement for a modified well site. Therefore, under the final rule, low production well sites remain affected facilities; however, they have the option of maintaining production at or below 15 boe per day on a continuous basis instead of implementing the fugitive monitoring requirement.

[55] See Section 2.5.1.1 of the TSD for additional information.

[56] For the multipollutant approach, the emissions of each pollutant are calculated based on the relative percentage of each pollutant in the gas emitted. Since the same control is applied to the gas emitted, the cost is divided in half to attribute the costs of control equally between the two pollutants (methane and VOC).

There are three timeframes in which we are requiring sources to calculate the total production from the well site. First, there are well sites that have not yet triggered the requirements in NSPS subpart OOOOa, which are those constructed, reconstructed, or modified after this final rule becomes effective. The owner or operator of such a well site has the option to calculate the total well site production based on the first 30 days of production. If the total production from all of the wells at the well site is at or below 15 boe per day (combined for both oil and natural gas produced at the site), then the owner or operator of the well site may either maintain production at or below this threshold on a rolling 12-month average or begin the fugitive emissions program. The owner or operator must comply with one of these two requirements at any and all times. If the total production of the well site is above 15 boe per day as determined in the first 30 days of production, then the site must begin the fugitive emissions program, including completing the initial monitoring within 90 days of startup of production. Recognizing that there are some well sites that have triggered the fugitive emissions requirements that may not have 12-months' worth of production data yet but are already able to demonstrate they are low production, the final rule contains a provision to allow the owner or operator to use production records based on the first 30 days of production after becoming subject to the NSPS to determine if the well site is low production. This determination must be made by December 14, 2020. After that date, the owner or operator may use the rolling 12-month average, as described next, for demonstrating the well site is low production.

Next, recognizing that production declines over time, we are also allowing an option for owners or operators subject to the monitoring requirement to determine whether the total production for the well site declines to 15 boe per day or below when calculated on a rolling 12-month average. If the total well site production is at or below this threshold on a rolling 12-month average, then the owner or operator has the option to stop fugitive monitoring and instead maintain total well site production below this threshold. The owner or operator must comply with either the fugitive monitoring requirement or maintain total well site production below this threshold at any and all times.

Finally, the EPA is aware that a low production well site could later increase production due to subsequent activities, as discussed above. For example, owners or operators commonly take actions to increase production as production declines or continue to drill new wells after the initial startup of production of the well site. If production subsequently increases to greater than 15 boe per day, it would be cost effective to implement the fugitive emissions monitoring requirement. In light of the above, the final rule requires that any well site that is not conducting fugitive emissions monitoring because total well site production is at or below the threshold must redetermine the total well site production following any of the following actions: A new well is drilled, a well is hydraulically fractured or re-fractured, a well is stimulated in any manner for the purpose of increasing production (including well workovers), or a well at the well site is shut-in for the purposes of increasing production from the well site. These well sites must recalculate the total well site production based on the first 30 days of production following the completion of that action. It is inappropriate to continue to utilize a rolling 12-month average because the production in the 11 months prior to the action that increased production would bias the average low. Like well sites constructed, reconstructed, or modified after this final rule, these well sites must recalculate the total well site production based on the first 30 days of production following the completion of that action to increase production.

We have not calculated the impacts of the production calculation because owners and operators are already required to track production for other purposes, regardless of environmental regulation, and we do not anticipate any additional burden associated with these records for purposes of this rule.

The final rule also requires semiannual monitoring of gathering and boosting compressor stations. As with fugitive monitoring of well sites, based on the revised cost analysis in the TSD for the final rule, the EPA reexamined the costs and emission reductions, including incremental cost and emission reductions, for various monitoring frequencies. In the October 15, 2018, proposed rulemaking, the EPA co-proposed annual and semiannual monitoring of fugitive emissions at all compressor stations. As previously discussed, the 2016 NSPS subpart OOOOa requires quarterly monitoring for compressor stations, including gathering and boosting stations, transmission stations, and storage stations. Therefore, the 2016 determination that quarterly monitoring was cost effective was based on the weighted average of the cost-effectiveness values for all of those station types. In the Review Rule, which was finalized in the **Federal Register** of Monday, September 14, 2020, the EPA has removed the transmission and storage segments from the Crude Oil and Natural Gas Production source category and rescinded the standards for those sources. As a consequence, only gathering and boosting compressor stations remain subject to the standards of NSPS subpart OOOOa.

After updating the compressor station model plants, the EPA estimates that the quarterly monitoring currently required by the 2016 NSPS subpart OOOOa has a cost effectiveness of $3,221/ton of VOC emissions reduced at gathering and boosting compressor stations. The EPA also considered the incremental cost effectiveness of going from semiannual monitoring to quarterly monitoring. This analysis showed that it cost $4,988/ton of additional VOC emissions reduced between the semiannual and quarterly monitoring frequencies. These values (total and incremental) are considered cost-effective for VOC reduction based on past EPA decisions, including the 2016 rulemaking. However, the incremental cost of $4,988/ton of additional VOC reduced is on the high end of the range that we had previously found to be cost-effective for VOC.[57] In contrast, semiannual monitoring is very cost-effective, at a total cost of $2,632/ton and incremental cost of $2,501/ton between annual and semiannual monitoring to reduce an additional 2,156 tons of VOC per year.[58] We further note that moving from annual to semiannual monitoring achieves the same incremental reduction in VOC emissions as moving from semiannual to quarterly monitoring (2,156 tons/year) but at half the cost per ton of additional VOC reduced ($2,501/ton instead of $4,988/ton). Moreover, additional factors influence our evaluation of the appropriateness of selecting quarterly monitoring as compared to semiannual monitoring for compressor stations. In particular, the oil and gas industry is currently experiencing significant financial hardship that may weigh against the appropriateness of imposing the additional costs associated with more frequent monitoring.[59] The EPA also acknowledges that there are potential efficiencies, and potential cost savings, with applying the same monitoring frequencies for well sites and compressor stations,[60] In light of all of these considerations, the EPA thinks it is reasonable to forgo quarterly monitoring and choose semiannual monitoring as the BSER for compressor stations. Table 5 provides a summary and comparison of these costs per ton of VOC reduced.

While this final rule does not have to consider the cost-effectiveness of controlling methane emissions, the EPA did evaluate those costs per ton of methane reduced. As discussed above for low production well sites, the highest costs per ton of methane reduced that we have found to be cost-effective in the past is $738/ton. Assigning all costs to methane (under the single pollutant approach) results in a total cost per ton of $895/ton and incremental cost per ton of $1,387/ton of methane reduced for quarterly monitoring, which almost doubles the highest cost per ton of methane reduced that we had previously found to be cost-effective ($738/ton). Under the multipollutant approach, the incremental cost per ton of additional methane reduced is $695/ton. While this incremental cost per ton is cost-effective, it is also at the high end of the range. Therefore, based on these costs per ton of methane reduced and considering the current financial hardships being experienced across the oil and gas industry, we would have similarly required semiannual monitoring even if methane had remained a regulated pollutant.

TABLE 5—COST-EFFECTIVENESS OF CONTROL FOR COMPRESSOR STATIONS SUBJECT TO FUGITIVE EMISSIONS STANDARDS UNDER SUBPART OOOOA OF 40 CFR PART 60

Monitoring frequency	Cost effectiveness ($/ton VOC)					
	Gathering and boosting stations			Compressor station weighted-average		
	2016 TSD total cost effectiveness [1]	2020 TSD total cost effectiveness [2]	2020 TSD incremental cost effectiveness	2016 TSD total cost effectiveness [1]	2020 TSD total cost effectiveness	2020 TSD incremental cost effectiveness
Annual	$2,105	$2,698		$3,278	$3,606	
Semiannual	2,443	2,632	$2,501	3,682	3,341	$2,811
Quarterly	3,391	3,221	4,988	5,006	3,908	5,607

[1] Values from the 2016 TSD have been adjusted for inflation for comparison purposes.

[2] As discussed in section V.B of this preamble, the EPA received comments that our original 2016 estimates were low, especially for recordkeeping and reporting burden. The 2020 estimates include adjustments to the 2016 estimates based on this information (which is higher than the 2016 TSD) plus include streamlined recordkeeping and reporting as well as other updates. In addition, the revised analysis found that the majority of the costs of the fugitive requirements are annual costs and do not vary with the monitoring frequency. That is, the recordkeeping and reporting burden remain consistent regardless of the monitoring frequency and the cost of each survey is not directly proportional to the incremental emissions reductions achieved at more frequent surveys. This is further explained in section V.B.2 of this preamble. Hence, Table 5 shows an increase in cost effectiveness for the annual and semiannual monitoring frequencies, but a decrease in the cost effectiveness for the quarterly cost effectiveness from the 2020 TSD. In contrast, the 2016 values presented here are directly from the 2016 TSD and have not been adjusted based on our new analysis of what the 2016 rule cost.

C. AMEL

The 2016 NSPS subpart OOOOa contains provisions for requesting an AMEL for specific work practice standards covering well completions, reciprocating compressors, and the collection of fugitive emissions components at well sites and compressor stations. While written with emerging technologies as the focus, the provisions in the 2016 NSPS subpart

[57] See 2007 NSPS subparts VV and VVa, 72 FR 64864, cited in the 2016 NSPS subpart OOOOa final rule, 80 FR 56636. See TSD for additional analysis and cost information, located at Docket ID No. EPA–HQ–OAR–2017–0483.

[58] See Table 2–35f of the TSD located at Docket ID No. EPA–HQ–OAR–2017–0483.

[59] See Iyke, B. N., 2020. ''COVID–19: The reaction of US oil and gas producers to the pandemic.'' Energy RESEARCH LETTERS, 1(2), located at *https://erl.scholasticahq.com/article/13912.pdf.*

See Gil-Alana, L. A., & Monge, M., 2020. ''Crude Oil Prices and COVID–19: Persistence of the Shock.'' Energy RESEARCH LETTERS, 1(1), located at *https://doi.org/10.46557/001c.13200.*

See Sharif, et al., 2020. ''COVID–19 pandemic, oil prices, stock market, geopolitical risk and policy uncertainty nexus in the US economy: Fresh evidence from the wavelet-based approach.'' International Review of Financial Analysis, 70, 7101496, located at *https://doi.org/10.1016/j.irfa.2020.101496.*

[60] See Docket ID Nos. EPA–HQ–OAR–2017–0483–0755 and EPA–HQ–OAR–2017–0483–0773.

OOOOa could also be used for state programs, though the application requirements were unclear on certain points. Therefore, the EPA proposed amendments to the application requirements as they relate to emerging technologies in order to streamline the application process, and proposed a new section to address state programs, including proposed alternative fugitive emissions standards based on our review of existing state programs. This section describes changes, based on information provided in public comments, to the AMEL provisions.

1. Emerging Technologies

The EPA continues to recognize that new technologies are expected to enter the market soon that could locate sources of fugitive emissions sooner and at lower costs than the current technologies required by the 2016 NSPS subpart OOOOa. While the EPA established a foundation for approving the use of these emerging technologies in the 2016 NSPS subpart OOOOa, we proposed specific revisions in the October 15, 2018, proposal to help streamline the application requirements and process. Specifically, we proposed to allow owners and operators to apply for an AMEL on their own, or in conjunction with manufacturers or vendors and trade associations. We also proposed to allow the use of test data, modeling analyses, and other documentation to support field test data, provided seasonal variations are accounted for in the analyses. While we received many supportive comments on these specific proposed amendments, we also received comments asserting that the application process is still too restrictive and burdensome to promote innovation.

First, the commenters stated that applications seeking approval of an alternative should be accepted by the EPA from manufacturers and vendors independently of owners and operators. We have reviewed the information provided by the commenters and agree that it is appropriate in the context of the revisions to 40 CFR 60.5398a to remove language that previously indicated from whom the Administrator would consider applications under that section because section 111(h)(3) of the CAA states ''any person'' can request an AMEL, and if they establish to the satisfaction of the Administrator that the AMEL will achieve emission reductions that are at least equivalent with the requirements of the rule, then the Administrator will allow the alternative. While the final rule allows any person to submit an application for an AMEL under this provision, the final rule still includes the minimum information that must be included in each application in order for the EPA to make a determination of equivalency and, thus, be able to approve an alternative. This final rule requires applications for these AMEL to include site-specific information to demonstrate equivalent emissions reductions, as well as site-specific procedures for ensuring continuous compliance.

Next, the commenters generally supported the proposal to allow the use of test data, modeling analyses, and other documentation to support field test data. In addition to their support of these supplemental data, commenters also requested that the final rule allow the use of information collected during testing at controlled testing facilities to be considered in lieu of site-specific field testing. The EPA considered whether it would be appropriate to allow this information and has concerns related to the representativeness of the information when compared to actual operating sites. For example, we are aware of one controlled testing facility located in the U.S., the Methane Emissions Technology Evaluation Center (METEC) located in Fort Collins, Colorado.[61] That facility is equipped with several different configurations of well pads using equipment that was donated from the oil and natural gas industry. The test well pads do not produce or process field gas; in fact, none of the equipment that is onsite is in contact with field gas. Instead, METEC utilizes compressed natural gas that is transported from offsite in order to create controlled leaks. In establishing controlled leaks, METEC uses tubing with leak points near typical leak interfaces to simulate a leak; however, these releases are not operated at pressures or temperatures that are typically encountered at an operating well site in the field. While we agree that testing at a controlled testing facility such as the METEC site can be helpful to understanding how a technology may perform, and the information gathered from such controlled test sites can be useful in supplementing other data, it is inappropriate to rely solely on the information collected at these types of facilities as being representative of how the technology would perform at an operating well site or compressor station. At this time, the EPA does not believe that it can determine the efficacy of a monitoring or detection technology where demonstrations take place only under controlled conditions. By extension, the EPA would be unable to determine the validity of whether an alternative indeed achieves equivalent emissions reductions if only presented with data from testing at a controlled testing facility. Therefore, we are finalizing amendments that require field test data, but that allow the use of test data, modeling analyses, data collected at controlled testing facilities, and other documentation to support and supplement field test data.

Next, we solicited comment on whether groups of sites within a specific area that are operated by the same operator could be grouped under a single AMEL. We received comments that discussed this broad application of alternatives in two distinct ways: (1) Allowing the aggregation of emission sources beyond the individual site in order to demonstrate equivalent emission reductions, and (2) allowing the use of approved AMELs at future sites that are designed and operated under the conditions specified in the approved AMEL. We evaluated both types of broad approval options raised in the comments by considering the definitions in the existing rule and the AMEL provisions of section 111(h)(3) of the CAA.

In the first instance, we evaluated whether it would be appropriate to allow the aggregation of emission sources beyond the individual site when evaluating the equivalency of an alternative. Specifically, we considered whether an applicant for an AMEL related to fugitive emissions monitoring could aggregate the total fugitive emissions across multiple sites within a specific geographic area, such as a basin, in order to demonstrate the requested AMEL would achieve at least equivalent emission reductions as the NSPS requirements for fugitive emissions monitoring and repair at an individual site. The work practice standards for the collection of fugitive emissions components at a well site or at a compressor station were established pursuant to section 111(h) of the CAA, which allows an opportunity for an AMEL. In accordance with section 111(h)(3) of the CAA, a source may use an approved AMEL for purposes of compliance with the established work practice. The commenters stated that the generic use of the word ''source'' allows aggregation of fugitive emissions components amongst multiple sites and is not limited to single sites. The EPA does not agree that aggregating fugitive emissions across multiple sites is a viable method to determine equivalency with the NSPS provided the definitions of affected facility in NSPS subpart OOOOa related to the collection of

[61] See *https://energy.colostate.edu/metec* for more information on the METEC facility.

fugitive emissions components. NSPS subpart OOOOa defines the ''source'' that is subject to the work practice standards for fugitive emissions as the ''collection of fugitive emissions components at a well site'' and the ''collection of fugitive emissions components at a compressor station'' in 40 CFR 60.5365a(i) and (j). These terms specify single-site applicability for the work practice standard. Because the rule does not define an affected facility or a source to be a geographic area, such as a basin, it is the EPA's determination that a demonstration of equivalent emission reductions for purposes of evaluating alternatives to the BSER has been based on the fugitive emissions at a single site, and not an aggregation of emissions across multiple well sites, compressor stations, or a combination of these two site types with an averaging or trading program akin to what the EPA has referred to in the past as a ''bubble'' approach. For further discussion on this topic, see section VI.C.2 of this preamble.

The second point raised by commenters was that requiring site-specific approvals (*i.e.,* AMELs that list specific well sites or compressor stations) would result in unnecessary burden as new sites with the same owner or operator, similar equipment, operating conditions, and in the same geographic area (*e.g.,* basin) are constructed. According to commenters, this unnecessary burden results from the need for the owner or operator to apply for an AMEL for each of these sites in the future, even though the AMEL would be identical to the previously approved AMELs for similar sites. We agree with the commenters that it is possible that AMELs could, where appropriate, be approved for future use at sites not included in the original application as discussed below. Commenters also encouraged the EPA to consider the potential for AMELs applicable to specific types of facilities with different owners or operators within an industry category or geographic region.

While the EPA is not amending 40 CFR 60.5398a at this time to address broad approvals of AMEL applications, we do recognize that the Agency has discretion in certain circumstances to allow for broad approval of alternatives via several different paths. First, for example, an applicant could submit an AMEL application for an alternative technology (and associated work practice) that includes specific site characteristics under which the technology (and associated work practice) has been tested and that demonstrates equivalent reductions to the standards in the NSPS. The application would include an explanation of these characteristics (*e.g.,* characteristics of the formation, operating conditions at the site, type of equipment and processes located at the site, and variables that affect performance of the technology or work practice) and a request that the EPA consider broad approval of the application such that sites (including those subject to the NSPS at the time of application and future sites) that meet the same characteristics could utilize the same approved alternative without the need for additional application to the EPA. The scope of such an approval might be limited based on any number of conditions as appropriate (such as those mentioned above). The EPA believes that, depending on the facts of the application, some type of broad approval may be a feasible path forward, but we will need to evaluate the information specific to the application in hand once received. As of the date of this final rule, the EPA has received no applications for AMELs to be able to determine if additional amendments (beyond those in this final rule) are necessary for such a situation, and how such potential amendments might be drafted to facilitate such broad approvals. In summary, if the applicant believes that it is appropriate to apply the alternative to more sites than those listed in the application because the proposed alternative can achieve equivalency for other sites, then the applicant should state this intent and make this demonstration to the EPA within the application. If provided with sufficient information, explanation, justification, and documentation, the EPA may determine under what defined conditions, if any, it is appropriate to allow the use of the alternative once approved at any site meeting those conditions, including sites constructed in the future.

Second, the EPA is interested in developing a framework in the future for AMEL requests that share similar characteristics (*e.g.,* technologies) in order to streamline both applications and approvals. While the EPA has not received applications related to the work practice standards in the 2016 NSPS subpart OOOOa, we have evaluated and approved AMELs for other sources in a few instances for one specific control technology, pressure assisted multi-point flares (for further information, see the EPA rulemaking Docket ID No. EPA–HQ–OAR–2014–0783). In the course of reviewing those applications, the EPA was able to establish testing criteria for this particular control technology to demonstrate equivalency with the underlying operational standards (*i.e.,* 98-percent control efficiency) as well as other certain design, equipment, and work practice standards, which, if met, would help streamline approval of applications submitted after that point. The EPA is committed to working with stakeholders to develop testing criteria for technologies and work practices for NSPS subpart OOOOa. However, due to the variability of this sector, as well as the wide-ranging array of technologies currently being pursued for development, we are unable to amend the language within this rule and provide such a framework at this time. For the pressure assisted multi-point flares, the EPA developed the testing framework in conjunction with an application and with stakeholder feedback from the first AMEL requests received and approved for that particular technology. We have not yet reached that critical first step of an application being submitted to the EPA to determine what testing framework might be appropriate, or how that framework might be technology family-specific (*e.g.,* continuous point monitors, aerial surveys, mobile equipment). We encourage interested stakeholders to continue engaging with us early in any application process so additional streamlining measures can be evaluated. The EPA is committed to improving this process of evaluating emerging technologies and may publish another request for information regarding technology innovation and the application process.

Third, if an applicant can demonstrate that a technology has very broad applicability across the entire industry, then, in addition to exploring the possibility of an AMEL, the EPA also would consider whether to undertake a rulemaking process to amend NSPS subpart OOOOa to allow for widespread use of the technology. As always, the EPA will review each application individually to determine if it has demonstrated that the alternative will achieve equivalent or greater emission reductions than the work practice standard the alternative would replace.

In summary, we are finalizing amendments to the application requirements for an AMEL in 40 CFR 60.5398a. We are allowing applications from any person. Further, we are allowing the use of supplemental data, such as test data, data collected at controlled testing facilities, modeling analyses, and other relevant documentation, to support field data that are collected to demonstrate the emissions reductions achieved. While we are not amending the rule to specifically state an approved AMEL can be used for future sources, we recognize that it may be possible, where appropriate, for the EPA to establish specific conditions during the AMEL process under which an approved alternative may be applied at sites not specifically listed in the application.

2. State Fugitive Emissions Programs

To reduce duplicative burdens to the industry related to the fugitive emissions requirements, the EPA proposed alternative fugitive emissions standards for well sites and compressor stations located in specific states. These alternative standards were proposed based on the EPA's review of the monitoring and repair requirements of the individual state fugitive emissions requirements [62] relevant to well sites and compressor stations. In the proposal, we stated that a well site or compressor station, located in the specified state, could elect to comply with the specified state program as an alternative to the monitoring, repair, and recordkeeping requirements in the NSPS. However, these sites would be required to monitor all fugitive emissions components, as defined in the NSPS, comply with the requirement to develop a monitoring plan, and report the information required by the NSPS because the sites remain affected facilities.

Similar to the proposed amendments for emerging technologies, we received support for the proposed amendments for state programs. However, some commenters stated that the EPA should recognize the approved state programs as wholly equivalent to the NSPS, including for all reporting and recordkeeping requirements. The commenters indicated that the EPA's equivalency determination still leaves the regulated community in certain states subject to duplicative requirements. They added that complying with two different reporting and recordkeeping schemes for the same site is very burdensome and provided no environmental benefit.

For the proposal, we evaluated 14 existing state programs to determine whether they are equivalent to the fugitive emissions requirements in 40 CFR 60.5397a. That evaluation included a qualitative comparison of the fugitive emissions components covered by the state programs, monitoring instruments, leak or fugitive emissions definitions, monitoring frequencies, repair requirements, and recordkeeping requirements to the requirements of the NSPS.[63] However, at the time of the proposal, the EPA had not evaluated the reporting requirements of the 14 individual state programs. We have completed that evaluation for this final rule for the state programs that we proposed as alternative standards and the results of that evaluation are discussed in more detail in section VI.C.2 of this preamble. We also updated the overall analysis of equivalency.[64] Through this additional evaluation, we concluded that the recordkeeping and reporting requirements of the various state programs do not need to be exactly equivalent to the requirements of the NSPS subpart OOOOa because the purpose of recordkeeping and reporting requirements is to ensure compliance with whatever standards apply. Obviously, the state programs we evaluated are not identical to the NSPS, so it stands to reason that their associated recordkeeping and reporting requirements might differ. Therefore, when evaluating the recordkeeping and reporting requirements in the individual state programs, we focused our review on the elements of those requirements that we deemed essential to a demonstration of compliance with the individual alternative standards. Sites remain subject to the NSPS, because the alternative standards are standards within the NSPS, therefore, compliance demonstrations are necessary through recordkeeping and reporting.

At a minimum, the EPA requires reports to include information that allows a demonstration of compliance for all fugitive emissions components (as defined in 40 CFR 60.5430a) at the individual site level (*i.e.,* well site or compressor station). This means the report must provide information on each individual monitoring survey conducted at each well site or compressor station adopting the alternative fugitive emissions standards. We reviewed the reports required under state law for the six states for which we are finalizing alternative fugitive emissions standards (*i.e.,* California, Colorado, Ohio, Pennsylvania, Texas, and Utah) to determine (1) if site-level information is required in the reports and (2) if the information reported demonstrates compliance through inclusion of elements such as the date of the survey, monitoring instrument used, information for each identified fugitive emission, repair information, and delayed repair information. For three of the six states (California, Ohio, and Pennsylvania) where we are finalizing alternative standards, the required state reports are site-specific and include information that will demonstrate compliance with the alternative standards. For the other three states (Colorado, Texas, and Utah), site-specific reporting is not required, or will not demonstrate compliance with the alternative standards. Therefore, the sites adopting the alternative standards for Colorado, Texas, and Utah, would need to provide the site-specific reports required in 40 CFR 60.5420a(b)(7). As discussed in detail in section V.B.2 of this preamble, the EPA is amending the recordkeeping and reporting requirements related to the fugitive emissions requirements. The result of these amendments is an annualized burden reduction of approximately 27 percent for well sites and 30 percent for gathering and boosting compressor stations, and those same burden reductions will be realized by sites in these three states.[65]

For the three states that do not require site-specific reporting, we reviewed the state's recordkeeping requirements to determine if any additional records would be necessary for reporting the required information under the NSPS. We found that for each of the three states, the records are very similar to, if not the same as, the information required under the NSPS. Given that additional records beyond those required by the state are not necessary, the EPA concludes that there is no duplicative recordkeeping burden associated with compliance with these alternative standards. This, in addition to the significant reduction in reporting burden discussed in section V.B.2 of this preamble, allows the EPA to conclude the submission of the reports required in 40 CFR 60.5420a(b)(7) presents minimal burden for sites in Colorado, Texas, and Utah.

Therefore, to summarize, the final rule requires reporting of information to demonstrate site-level compliance with the alternative fugitive emissions standards as follows:

- Where the state report includes site-specific information for each fugitive emissions survey that demonstrates compliance with the alternative

[62] Note, several states refer to the fugitive emissions standards as LDAR.

[63] See memorandum, ''Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Final Standards at 40 CFR part 60, subpart OOOOa,'' located at Docket ID No. EPA–HQ–OAR–2017–0483. January 17, 2020.

[64] See memorandum, ''Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Final Standards at 40 CFR part 60, subpart OOOOa,'' located at Docket ID No. EPA–HQ–OAR–2017–0483. January 17, 2020.

[65] See TSD for additional information on the estimated cost burden at the individual site level at Docket ID No. EPA–HQ–OAR–2017–0483.

standard, the owner or operator has the option to either (a) provide the EPA with a copy of the state report, in the format in which is it submitted to the state, based on the following order of preference: (1) As a binary file; (2) as an Extensible Markup Language (XML) schema; (3) as a searchable portable document format (PDF); or (4) as a scanned PDF of a hard copy, or (b) provide the report required by 40 CFR 60.5420a(b)(7)(i) and (ii) to the EPA in accordance with the applicable reporting procedures.

- Where the state report does not include site-specific information for each fugitive emissions survey, the owner or operator must report the information required by 40 CFR 60.5420a(b)(7)(i) and (ii) to the EPA in accordance with the procedures applicable to such a submission.

Any owner or operator has the option to complete the information required by 40 CFR 60.5420a(b)(7) in lieu of submitting a copy of the state report. As described in section IV.I of this preamble, electronic reporting through CEDRI is now required for all reports under 40 CFR 60.5420a(b). Thus, the EPA is requiring electronic submission of reports for the alternative fugitive emissions requirements, regardless of whether the state continues to allow paper copy submissions.

The EPA believes that adoption of these alternative standards will further reduce the burden of the fugitive emissions standards on the industry from this rule. No additional recordkeeping beyond that required by the alternative standard is necessary. Additional justification for the EPA's decision to adopt these state programs as alternative fugitive emission standards is provided in the memorandum [66] summarizing the EPA's review of each state program's requirements and in section VI of this preamble.

We note that one commenter expressed concern over the proposed state equivalency determinations and noted that several of the programs evaluated have specific applicability thresholds where the standards only apply to a subset of sources, whereas the NSPS applies to all new, modified, or reconstructed sources.[67] We agree that the applicability thresholds for these state programs are different from the NSPS, but we do not agree that additional regulatory text is necessary to address this concern. The regulatory thresholds included in state programs that limit or reduce monitoring and repair requirements do not affect the requirements for sources subject to the NSPS. Therefore, if a site subject to the NSPS is not also subject to the state program because of the state-specific applicability threshold, the site would still be required to comply with the requirements of the NSPS. Where appropriate, we have amended the regulatory text to clearly define the requirements of the alternative standard. More discussion of this comment and our response is provided in section VI.C.2 of this preamble.

VI. Summary of Significant Comments and Responses

This section summarizes the significant comments on the proposed amendments and our responses to those comments. Additional comments and responses are summarized in the RTC document available in the docket.

A. Major Comments Concerning Storage Vessels

The EPA received numerous comments on the proposed amendments to the definition of ''maximum average daily throughput,'' which is key in the determination of storage vessel affected facility status under the 2016 NSPS subpart OOOOa. Many of the comments we received were related to manifolded storage vessel systems. The EPA considered those comments and is finalizing changes to the rule to address a subset of these manifolded storage vessel systems (*i.e.,* controlled storage vessel batteries as described in section V.A of this preamble). A more detailed summary of the comments regarding controlled storage vessel batteries, and our responses to those comments, is available in the RTC document for this action (see Chapter 6).[68]

In addition to the comments the EPA received on controlled storage vessel batteries, we also received other comments related to storage vessel applicability determination criteria. Below is a discussion related to three of these topics: (1) The use of legally and practicably enforceable limits that maintain VOC emissions from storage vessels below 6 tpy, (2) the calculation of maximum average daily throughput based only on the days of actual production in the first 30 days, and (3) the determination of maximum average daily throughput for storage vessels at gathering and boosting compressor stations, onshore natural gas processing plants, and transmission and storage compressor stations.

Comment: Some commenters stated that the EPA proposed additional parameters on what constitutes a ''legally and practicably enforceable'' limit; and, therefore, heightened the standard for allowing use of such limit in estimating a storage vessel's potential VOC emissions for purposes of determining applicability of the storage vessel standards at 40 CFR 60.5395a. Specifically, the commenters took issue with the statement in the preamble to the October 15, 2018, proposed rulemaking where the EPA stated ''only limits that meet certain enforceability criteria may be used to restrict a source's potential to emit, and the permit or requirement must include sufficient compliance assurance terms and conditions such that the source cannot lawfully exceed the limit.'' 83 FR 52085. One commenter claimed that these additional criteria (1) conflict with prior EPA statements made during earlier oil and gas NSPS rulemakings; (2) conflict with the EPA's traditional practice of deferring to states regarding the appropriate mechanisms for limiting potential to emit (PTE); (3) raise concerns about how this new interpretation/approach would apply in the title V and New Source Review/Prevention of Significant Deterioration context where operators are relying on the same control requirements to limit their PTE; (4) raise significant concerns about retroactive application; and (5) ignore that the requirements for fugitive components under the 2016 NSPS subpart OOOOa are not tied to storage tank applicability and apply regardless of whether a storage tank is an affected facility under the rule.

Commenters also cited the EPA's ''enforceability criteria'' guidance, which was first introduced in 1995, and asserted that the EPA's proposed additional criteria were not consistent with that guidance. One commenter was concerned that the EPA's proposal not only conflicted with the Agency's traditional and consistent practice, it also threatened to subject sources to the NSPS that already determined their potential for VOC emissions was below the 6 tpy threshold by using the EPA's prior guidance.

Response: The EPA disagrees with the commenters because we did not propose additional parameters on what would constitute a legally and practicably enforceable limit. Rather, in the proposal preamble, the EPA simply summarized its position on this matter based on the existing substantial body of EPA guidance and administrative

[66] See memorandum, ''Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Final Standards at 40 CFR part 60, subpart OOOOa,'' located at Docket ID No. EPA–HQ–OAR–2017–0483. January 17, 2020.

[67] See Docket ID Item No. EPA–HQ–OAR–2017–0483–2041.

[68] See Chapter 6 of the RTC document located at Docket ID No. EPA–HQ–OAR–2017–0483.

decisions relating to potential emissions and emissions limits. As the EPA explained, limits that meet certain enforceability criteria may be used to restrict a source's potential emissions. For example, any such emission limit must be enforceable as a practical matter, which requires that the permit or requirement specifies how emissions will be measured or determined for purposes of demonstrating compliance with the limit. The permit or requirement must also include sufficient terms and conditions such that the source cannot lawfully exceed the limit (*e.g.,* monitoring, recordkeeping, and reporting). For additional information and a summary of the EPA's position on establishing legally and practicably enforceable limits on potential emissions, including examples of ''enforceability criteria,'' see In the Matter of Yuhuang Chemical Inc. Methanol Plant St. James Parish, Louisiana, Order on Petition No. VI–2015–03 (August 31, 2016) at 13–15.

Comment: Under the 2016 NSPS subpart OOOOa, the applicability of the storage vessel standards is based on a single storage vessel's potential for VOC emissions, which is calculated using the storage vessel's ''maximum average daily throughput.'' While ''maximum average daily throughput'' is defined in 40 CFR 60.5430a of the 2016 NSPS subpart OOOOa, several stakeholders indicated that clarification of this definition was needed. As a result, the EPA proposed a revised definition. 83 FR 52106. The EPA received several comments related to the proposed definition, which requires that ''production to a single storage vessel must be averaged over the number of days production was actually sent to that storage vessel.'' Most of the commenters objected to this proposed definition, claiming that it would be more appropriate to average over the entire 30-day evaluation period rather than only those days when production was sent to the storage vessel. With regard to tank batteries, one commenter asserted that the proposed definition would not result in an accurate estimate of the potential emissions from individual storage vessels because it would overestimate the total amount of production that each tank could receive over the 30-day evaluation period. Further, the commenter stated that the proposed definition would significantly overestimate the volume of flow to the tank battery as a whole when compounded across multiple tanks and extrapolated across an entire year. Multiple commenters also generally stated that the EPA's proposed definition failed to account for the fact that maximum well production has a limit based on what the wells can produce. However, the EPA did receive one comment that agreed with the proposed definition and that owners and operators should not be able to include days where the storage vessel does not receive production when determining storage vessel applicability.

Response: The EPA disagrees with the comments suggesting that ''maximum average daily throughput'' should be determined by averaging across the full 30-day evaluation period instead of the days when production is actually sent to an individual storage vessel during that period. As stated in the proposal, the maximum average daily throughput ''was intended to represent the maximum of the average daily production rates in the first 30-day period to each individual storage vessel,'' 83 FR 52084, which is not the same as an average daily production rate based on averaging total production across a full 30-day period. As explained further in the proposal, in all possible scenarios for determining the daily production, only the number of days in which production is sent to the individual storage vessel is used for averaging, which may be less than the full 30 days in the evaluation period. Indeed, including days where no production was received would reduce the maximum average daily throughput to an individual storage vessel under any of the scenarios described in the proposal. 83 FR 52084. The commenters did not explain how averaging actual throughput to a storage vessel across the full 30 days would accurately reflect the ''maximum average daily production rates,'' therefore, we do not agree with the commenters' suggestion to use this value for the purpose of determining a storage vessel's potential for VOC emissions.

The EPA also disagrees with comments suggesting that the EPA's proposed definition would overestimate the potential for VOC emissions for individual storage vessels in a tank battery by failing to account for the overall production to the tank battery during the 30-day period. In addition to the definition of ''maximum average daily throughput'' which provided for two operational scenarios, the EPA further explained in the proposal how to determine the daily or average daily throughput, from which the maximum average daily throughput is determined, depending on how throughput is measured. 83 FR 52084. The EPA's proposed definition is based on either the daily (*i.e.,* directly measured via automated level gauging or daily manual gauging) or average daily (*i.e.,* manual gauging at the start and end of loadouts which occur over more than one day) throughput routed to a storage vessel while receiving production; the fact that the storage vessel is receiving that amount daily clearly indicates that it has the potential to do so. The total throughput to the entire tank battery during the 30-day period is not germane to this determination. Because there are likely multiple daily throughput or average daily throughput values for an individual storage vessel during the 30-day evaluation period, the maximum of those values is used to calculate the potential for VOC emissions, thus, the use of the term ''maximum average daily throughput.''

While the EPA is finalizing the definition of ''maximum average daily throughput'' as proposed, we note that the final rule provides other mechanisms for determining a storage vessel's applicability without having to calculate the maximum average daily throughput. Specifically, the final rule allows owners and operators of controlled tank batteries meeting specified criteria to average VOC emissions across the number of storage vessels in the tank battery to determine applicability for the individual storage vessels in the battery. Also, as provided in the 2016 NSPS subpart OOOOa, and unchanged by this final rule, if a facility has a legally and practicably enforceable limit that restricts production to an individual storage vessel, then it is acceptable to use this restricted production level as the maximum average daily throughput for that individual storage vessel.

Comment: Commenters stated that the methods for determining the potential for VOC emissions from storage vessels in the 2016 NSPS subpart OOOOa were not appropriate for storage vessels located at compressor stations (including gathering and boosting compressor stations) and onshore natural gas processing plants, and they indicated that the proposed revisions to 40 CFR 60.5365a(e) and the definition of maximum average daily throughput did not alleviate this problem. More specifically, commenters noted that the 2016 NSPS subpart OOOOa is clear that storage vessels at well sites must determine the potential for VOC emissions based on the maximum average daily throughput based on the first 30 days that liquids are sent to the storage vessel. The commenter noted that storage vessels at compressor stations and onshore natural gas processing plants are designed to receive liquids from multiple well sites that may start up production over a longer period of time. Because these storage vessels may not experience the same peak in throughput to the storage vessels during the first 30-days of receiving liquids as storage vessels at well sites, the commenter indicated that owners or operators may underestimate the potential emissions using the throughput for the first 30 days. Therefore, commenters requested that the EPA clarify the appropriate time period for calculating the maximum average daily throughput for storage vessels at facilities located downstream of well sites. Alternatively, commenters suggested that storage vessels at gathering and boosting compressor stations be allowed to use generally accepted engineering models that project future throughput. The commenters explained that compressor stations (including gathering and boosting compressor stations) and onshore natural gas processing plants typically utilize process simulations based on representative or actual liquid analysis to determine potential VOC emissions and volumetric condensate rates from the storage vessels based on the maximum gas throughput capacity of each facility. These generally accepted engineering models and calculation methodologies are then utilized to obtain Federal, state, local, or tribal authority issued permits to set legally and practicably enforceable limits to maintain potential VOC emissions from storage vessels at less than 6 tpy. The commenter requested that the EPA allow use of these generally accepted models and calculation methodologies to project future maximum throughput volumes.

Response: The EPA agrees with these commenters that potential VOC emissions from storage vessels at facilities downstream of well sites should not be determined based on the first 30 days that liquids are sent to those storage vessels as they are unlikely to experience the same peak in throughput during that period as storage vessels at well sites. It is the EPA's understanding, based on the information provided by the commenters and subsequent conversations,[69] that these midstream and downstream storage vessels may continue to see an increase in throughput as additional upstream well sites begin sending fluids to these compressor stations and onshore natural gas processing plants. Based on the EPA's review and understanding of the generally accepted engineering models for projecting future throughput to a storage vessel, the EPA agrees that these engineering models are appropriate for projecting the maximum throughput for purposes of calculating the potential for VOC emissions from storage vessels located downstream of well sites.

Based on the above reasons, the EPA is amending the 2016 NSPS subpart OOOOa to specifically provide the following two options for determining the potential for VOC emissions from storage vessels at facilities downstream of well sites. The first option, which is already allowed in the 2016 NSPS subpart OOOOa, allows owners or operators to take into account throughput and/or emission limits incorporated as legally and practicably enforceable limits in a permit or other requirement established under a Federal, state, local, or tribal authority. The second option allows the use of generally accepted engineering models (*e.g.,* volumetric condensate rates from the storage vessels based on the maximum gas throughput capacity of each producing facility) to project the maximum throughput used to calculate the potential for VOC emissions.

B. Major Comments Concerning Fugitive Emissions at Well Sites and Compressor Stations

In section V.B of this preamble, we discuss the significant changes from the proposal to this final rule related to the fugitive emissions requirements for well sites and compressor stations. The discussions in section V.B of this preamble include a summary of the major comments and our responses related to those changes. Specifically, section V.B of this preamble discusses the following topics: (1) The three areas of uncertainty potentially affecting the cost-effectiveness analysis that were identified in the October 15, 2018, proposal; (2) recordkeeping, reporting, and other administrative burden from the fugitive emissions requirements; (3) other updates to the model plants; and (4) cost effectiveness of fugitive emissions requirements. We also discuss our re-evaluation of BSER after consideration of all these topics.

In addition to the topics discussed in section V.B of this preamble, the EPA received comments on other aspects related to the fugitive emissions requirements. This section provides a discussion of comments and our responses regarding the following three topics: (1) The EPA's model plant analysis for low production well sites; (2) the effect of system pressure on fugitive emissions at low production well sites; and (3) monitoring of compressors at compressor stations when operating and not in standby mode. More detailed summaries and additional comments on the fugitive emissions requirements are included in Chapter 8 of the RTC document included in the rulemaking docket for this action.

Comment: The EPA created model plants representing low production well sites for purposes of analyzing the emissions and costs of a fugitive emissions monitoring and repair program at these types of well sites. In the proposal, we also acknowledged that operating pressures and production volumes are factors that can cause changes in the fugitive emissions at a well site. 83 FR 52067. However, the EPA was unable to incorporate these factors into the emission estimates in the model plants, and, therefore, developed model plants that relied on equipment and component counts to analyze fugitive emissions from low production well sites.

Some industry commenters disagreed with the use of model plants that rely on component counts alone to estimate fugitive emissions from low production wells due to differences in the type and size of equipment and operating conditions (*e.g.,* operating pressure) at low production well sites. The commenters did agree that it is reasonable to associate the number of components to the potential for leaks. However, the commenters continued to maintain that emissions from low production wells are inherently different from large production wells because of the basic physics of production and how operators change the physical equipment as production warrants. Commenters indicated that the fugitive emissions factors used by the EPA, which were developed for generally predicting emission levels, account for different types of fugitive emission components, but do not factor in the amount of production or line pressure.

Response: As stated in the proposal, the EPA continues to recognize that variations in equipment, operating conditions, and geological aspects across the country at low production well sites may affect fugitive emissions from low production well sites. As described in section V.B of this preamble, we have made updates to the low production well site model plants and re-evaluated the emissions and costs of fugitive emissions monitoring and repair requirements at low production well sites. Based on this updated analysis, the EPA concludes that fugitive emissions monitoring and repair is not cost effective at any monitoring frequency for low

[69] See memorandum for ''May 1, 2019 Meeting with GPA Midstream,'' located at Docket ID No. EPA–HQ–OAR–2017–0483.

production well sites. See section V.B of this preamble for additional discussion.

Comment: The EPA received additional comments and data related to the low production well site model plants developed and analyzed for the proposal. One commenter conducted a brief survey of its member companies' gas well site operations in 13 states and provided low production well site component counts. This commenter pointed out that the majority of emissions (around 80 percent) from the low production well site model plants are from valves and storage vessel thief hatches. Therefore, the commenter only provided counts of these components, along with the number of wellheads. This commenter explained that the data show fewer wellheads and valves than assumed in the proposal model plant for low production gas well sites. The commenter stated that it did not consider the data to be fully representative of low production well sites nationwide; nevertheless, relying on the difference in component counts, the commenter claimed that the EPA overestimated the fugitive emissions in the low production model plants used for the proposal.

Response: While the commenter specifically stated that it did not consider the data to be fully representative of low production well sites nationwide, we reviewed the information and compared it to the low production well site model plants used for the proposal analysis. Specifically, we compared the weighted-average component counts of the information provided by the commenter to the EPA's low production well site model plant. The information provided by the commenter showed that the weighted-average number of storage vessels was approximately the same as that used in the EPA model plant, the number of well heads was half (one versus two in the EPA model plant), and the number of valves was just under 25 percent (23 versus 100 in the EPA model plant). If the model plant was modified with these adjusted component counts, the overall difference in emissions would be just over 50 percent.

After consideration of this information, the EPA concluded it provides an insufficient basis to revise the low production well site model plant component counts because the information was limited to valves, connectors, and storage vessels at a sample of sites the commenter admitted were not fully representative of low production well sites. However, as discussed above in section V.B of this preamble, we did conduct further review of the data originally used to develop the model plant parameters, as well as GHGI data. That review resulted in a 35-percent decrease in the number of valves for the low production gas well site model plant, as well as decreases in the numbers of the other components. More detailed information on our analysis of the component count information submitted by commenters is contained in a technical memorandum.[70] As shown in the revised model plant analysis, a fugitive emissions monitoring program is not cost effective for low production well sites at any of the frequencies analyzed.

Comment: The EPA proposed defining low production well sites as sites where the average combined oil and natural gas production for the wells at the site is at or below 15 boe per day averaged over the first 30 days of production. 83 FR 52093. Several commenters recommended changing the definition of a low production well site to be based on the U.S. Tax Code definition of stripper wells. These commenters also recommended using 12 months of production to determine if a site is low production because most well sites newly affected by NSPS subpart OOOOa will not meet the definition based on the first 30 days of production and because production declines over time such that eventually all well sites become low production.

Response: The EPA has not adopted the stripper well definition for purposes of determining if a well site is low production in this action because the U.S. Tax Code definition applies to individual wells, not well sites. The fugitive emissions standards apply to the collection of fugitive emissions components located at a well site. Adoption of the stripper well definition could result in a scenario where one well at the site is considered low production but the other wells are not, which is inconsistent with the affected facility definition for fugitive emissions components, where the entire site is treated as one unit. Therefore, the calculation of production for purposes of determining if the well site is low production is based on the total well site production and not the individual well production averaged across the number of wells at the well site.

However, the EPA does agree with the commenters that determination of low production status based solely on the first 30 days of production does not account for decline in production over time. Therefore, the final rule specifies that a low production well site is a well site with total well site production of oil and natural gas at or below 15 boe per day. This calculation can be based on the first 30 days of production for determining initial applicability to the rule and based on a rolling 12-month average to account for production decline. See section V.B of this preamble for additional discussion.

Comment: Commenters urged the EPA to use the Department of Energy (DOE) research program[71] announced on October 23, 2018, to determine more accurate assessments of low production well emissions. The commenters asserted that the DOE study provides the EPA the opportunity to collect direct emissions data on fugitive emissions at low production well sites. The commenters concluded that these data would provide the EPA with a baseline that shows the distinctions between large wells and low production wells and the differences that may exist between types of wells and between production regions.

Response: The EPA is regularly updated on the DOE program and provides technical input on many projects. However, data from the DOE-funded study on low production wells are not currently available. The conclusions made in this final rule are based on currently available information, which includes many data sources that cover low production wells, such as DrillingInfo, Greenhouse Gas Reporting Program, and other emission measurement studies. As discussed in this section and in section V.B of this preamble, the EPA agrees that existing information shows that low production well sites may have lower emissions than well sites with higher production. As such, the final rule has separate requirements for well sites with total production at or below 15 boe per day, instead of the required fugitive emissions monitoring program (including semiannual monitoring) for well sites above this production threshold.

Comment: In addition to co-proposing annual monitoring of fugitive emissions components located at a compressor station, the EPA proposed a requirement that each compressor at the station must be monitored at least once per calendar year when it is operating. The EPA also solicited comment regarding the effect the compressor operating mode has on fugitive emissions and the proposal to require at least one monitoring a year during times that are representative of operating conditions for the compressor station.

[70] Memorandum. ''Summary of Data Received on the October 15, 2018 Proposed Amendments to 40 CFR Part 60, subpart OOOOa Related to Model Plant Fugitive Emissions.'' February 10, 2020.

[71] *https://www.netl.doe.gov/node/5775.*

Several industry commenters opposed the EPA's proposal to require that each compressor be monitored while in operation (*i.e.,* not in stand-by mode), because if the station is subject to annual monitoring (which was co-proposed), this requirement would result in a requirement for every compressor to be operating during the monitoring survey, even if all of the compressors are not needed at that time to move gas downstream. The commenters believed that the result of this requirement would be the generation of emissions from compressor blowdowns following the monitoring survey in order to return the compressors to the operating modes they were in prior to the survey. The requirement would also create unnecessary recordkeeping and scheduling complexity/burden, according to commenters. Requiring equipment to be monitored in a specific mode of operation, especially at less frequent monitoring than quarterly, would increase overall emissions if that equipment must change its operational status solely to fulfill that requirement. These commenters recommended that the EPA allow operators to conduct surveys with facility operations as they are found when the survey is conducted.

However, another commenter stated that its data suggests that it is important to conduct monitoring on fully operating compressors to maximize the number of leaks detected. The commenter stated that beyond these data, it is also simply common sense that as the ratio of pressurized to depressurized components increases, so will the number of leaks detected (depressurized components do not leak). One of the problems is that operation modes vary seasonally at each compressor station, and within each compressor station, the operating modes of each unit can vary daily based on demand. The commenter asserted that the current quarterly compressor monitoring frequency creates a higher probability of conducting a survey where each compressor is monitored in a pressurized mode at least once per year. If the EPA moved to less frequent monitoring, the commenter recommended that there should be some condition to ensure that a reasonable effort is made to schedule the surveys during a time of peak operation.

Response: The EPA reviewed the input provided by the commenters. While we agree with the one commenter that the opportunity for fugitive emissions is greater when a compressor is pressurized and operating, the EPA is not finalizing the proposed requirement that each compressor must be monitored while in operation (*i.e.,* not in stand-by mode) at least annually. The EPA has specified in the final rule that the monitoring survey of fugitive emissions components at a gathering and boosting compressor station is semiannual after the initial survey and subsequent semiannual monitoring surveys must be conducted at least every 4 to 7 months. Therefore, as pointed out by the commenter, the likelihood that all monitoring events in a year will be when a specific individual compressor is not operating is relatively low. For the reason stated above, this final rule does not require monitoring of each individual compressor at the station while it is in operation (*i.e.,* not in stand-by mode) at least once per calendar year.

However, the EPA does conclude that it is important that the operating mode during the monitoring survey be recorded. While we would not expect that owners or operators would modify their operating schedules to avoid monitoring when the compressor is operating, or that they would purposely schedule every monitoring event during shutdown periods, we believe that this record would inform the Agency if this were occurring and, if so, how often. This information will provide valuable points for future analyses on leak rates and operating modes. Therefore, the final rule requires that owners and operators keep a record of the operating mode of each compressor at the time of the monitoring survey.

C. Major Comments Concerning AMELs

1. Emerging Technologies

The EPA received comments related to AMELs for emerging technologies on several topics. The comments received by the EPA that resulted in significant rule changes are discussed in section V.C.1 of this preamble, along with our response and rationale for the changes. The specific topics were (1) who can submit an AMEL application, (2) what data can or must be included in an AMEL application, and (3) what broader applications of alternatives are permitted. Further details on comments related to the broader applications of AMEL technology, specifically on the issues of applying AMEL to multiple similar sites or to categories of sources, are provided below along with the EPA's responses. Other comments, and more detailed comments covering the topics discussed in this preamble related to emerging technologies can be found in the RTC document available in the docket, along with EPA's responses.

Comment: In the proposal, the EPA reiterated its position that AMEL approvals would be made on a site-specific basis but noted that applicants could include multiple sites within one application as necessary. Many commenters disagreed with that proposal, stating that the EPA should allow approved AMELs to apply more broadly to multiple sites, basin-wide, industry-wide, or even based on nation-wide efficacy. Commenters asserted that restricting AMEL approval to a specific site is inconsistent with the EPA's past practice for OGI, in which the EPA determined that OGI achieves emission reductions equivalent to Method 21 for several industries and source categories in a single rulemaking.[72] Some commenters feared that the site-specific approval process that includes **Federal Register** notice and comment requirements is so onerous that it will stifle innovation in new technology, and another noted that its customers have indicated that they would not apply for an AMEL if approval is site-specific. Commenters pointed out that the site-specific approval process could create a crush of AMEL applications for hundreds or thousands of sites, but the applications would be limited to only the technologies previously approved or most likely to be approved as AMEL.

In response to the EPA's concern that alternative technologies may need to be adjusted for site-specific conditions, such as gas compositions, allowable emissions, or the landscape, several commenters suggested that the EPA could account for factors affecting variability, such as the weather or landscaping, by imposing conditions for the use of the technology and/or require periodic instrument checks, calibration records, or other actions to ensure equivalent emission reductions are achieved within the approved AMEL. The commenters also noted that if there is concern about allowable emissions impacting the usability of a particular technology, that technology may only be approvable for use as an approach to direct inspection efforts, but this factor would not affect the ability for it to be approved for that use at multiple sites.

Response: The EPA does not seek to stifle innovation of emerging technologies. In fact, the Agency is actively involved in many multi-stakeholder groups aimed at developing frameworks and criteria that will promote the development of possible alternatives. As such, the EPA strongly encourages interested parties to discuss possible alternatives with the Agency.

[72] See the Alternative Work Practice located at 40 CFR 60.18(g), (h), and (i).

However, the EPA disagrees that this final rule should be the vehicle used to make determinations about any particular technology because the proposed rulemaking did not evaluate any specific technology. The EPA also disagrees that this rule is inconsistent with the EPA's past practice for OGI, in which the EPA allowed the use of OGI as an alternative to Method 21 for several industries and source categories in a single rulemaking.[73] The EPA notes that while the AMEL process provided for in CAA section 111(h)(3) contains elements similar to a rulemaking (such as notice and opportunity for public hearing), approval of an alternative does not always require rulemaking. If a technology is developed that could be broadly applied to oil and gas sites as an alternative to what is required in NSPS subpart OOOOa, it may be more appropriate to incorporate such a technology into the rule through a formal rulemaking process so that every affected facility can make use of that alternative.

As discussed in section V.C.1 of this preamble, the EPA agrees that in some circumstances, it may be appropriate to apply an approved AMEL to multiple sites, including future sites. If the applicant of an AMEL believes that it is appropriate to apply the alternative to more sites than those listed in the application, the applicant should specify this within the application and provide any characteristics or variables that are applicable to the type of sites where the equivalency demonstration is being made. Specifically, the applicant should provide relevant information, including any specific conditions (*e.g.,* technology-specific variables that affect performance), procedures (*e.g.,* specific work practice that will be followed to identify emissions and make repairs), or site characteristics under which the alternative must be applied (*e.g.,* formation variables, site operating conditions, equipment at the site, etc.), to demonstrate equivalence with the emissions reductions that would be achieved under the requirements of the NSPS. The EPA will evaluate these defined conditions and additional conditions, if any, under which it might be appropriate to allow future use of the alternative once approved via the AMEL process. For example, the EPA might approve the use of a specific fugitive emissions detection technology that operates with the same performance under specific work practice requirements, environmental conditions, and site configurations and operations. In that example, the EPA might determine it is appropriate to approve the AMEL and define the specific parameters (*e.g.,* environmental conditions, site configurations, and operations) within the approval to allow the use of that alternative at sites meeting those same conditions without the need for additional future application to the EPA. However, each of these determinations would necessarily be made on a case-by-case basis provided the application contains all necessary information to make such a broad determination for applicability of the AMEL. Given that these determinations are made on facts and showings that are specific to each proposed alternative, the EPA has determined that the best course forward is for an applicant to submit an application seeking a broadly applicable AMEL and for the Agency to then use its evaluation of that application as a template for future applications, thereby streamlining the process.

Comment: Several commenters stated that the EPA should approve the use of alternative technologies under the Agencies' AMEL authority for broad categories of sources subject to NSPS subpart OOOOa, such as fugitive emissions components across multiple sites. They remarked that there is nothing in the statute that requires the EPA to set source-specific AMELs, and the EPA's position regarding the necessity of source-by-source applications and approvals for AMEL is incorrectly taken from a narrow reading of the language of CAA section 111(h)(3). The commenters stated that, while the language of CAA section 111(h)(3) provides that an AMEL is permitted to be used ''by the source'' for purposes of compliance, the EPA's reading of this provision to disallow the granting of AMEL for use by multiple sources is inconsistent with the NSPS approach of developing standards for whole categories of sources.

Some commenters said that because an AMEL will serve as a replacement for a category-wide CAA section 111(h)(1) standard, a demonstration that an AMEL will achieve an emission reduction at least equivalent to a CAA section 111(h)(1) standard could be made on a category-wide basis and be applied to an entire source category. These commenters suggested that allowing for source category-wide AMEL determinations would be consistent with the overall structure of CAA section 111 and its focus on category-wide standards under CAA sections 111(b) and (h)(1) and with the limitation prohibiting the EPA from imposing specific technological emission reduction requirements pursuant to CAA section 111(b)(5).

These commenters further stated that the EPA's regulation implementing CAA section 112(h)(3) recognizes that the EPA is authorized to approve an AMEL for ''source(s) or category(ies) of sources on which the alternative means will achieve equivalent emission reductions.''[74] They contended that, given the similarities between the programs authorized under CAA section 111 and CAA section 112, and particularly the similarity of CAA sections 111(h)(3) and 112(h)(3), the EPA should adopt a policy of applying an AMEL to source categories for CAA section 111(h)(3) in the same manner as it has done with respect to CAA section 112(h)(3). They noted that in other rules, such as the visibility provisions that require the best available retrofit technology (BART), the EPA's rules allow the EPA and the states to authorize BART alternatives that can apply to groups of sources and that allow emission averaging across sources, even over wide regions, rather than imposing source-specific emission limits or source-specific alternatives to such limits. The commenters stated that if alternatives to emission limits (or work practice standards) for groups of sources under these provisions are permissible despite the continued references to the term ''source'' in the statutory language, then a source category-wide AMEL is surely permissible under CAA section 111(h)(3).

Response: On the first point raised by commenters, and as explained in the EPA's response above, the EPA agrees that in some instances broad use of an approved alternative may be appropriate. The current construct of the AMEL application process in NSPS subpart OOOOa does not prevent the EPA from taking this path as suggested by the commenters.

The commenters also suggest that the EPA should apply AMEL to a source category in the same manner in which the EPA has done for applications submitted through section 112(h)(3) of the CAA. While the EPA has approved AMEL for sources subject to standards under section 112 of the CAA, these approvals have been made on a site-specific basis, in which each application specifically lists the facilities that are applying for approval. Further, while similar, CAA section 112(h)(3) does not apply for purposes of demonstrating equivalence with work practice standards in the NSPS.

[73] See 40 CFR 60.18(g), (h), and (i).

[74] See 40 CFR 63.6(g)(1).

For purposes of evaluating whether an alternative to fugitives monitoring provides at least equivalent emission reductions as the applicable standards in the context of NSPS subpart OOOOa, the EPA asserts that the emissions from an individual site are the only appropriate measure for comparison. First, the BSER determination for the collection of fugitive emissions components is based on a single well site, or a single compressor station, not a collection of well sites and/or compressor stations, and not the emissions of the entire source category. The source category for which NSPS subpart OOOOa sets standards of performance under CAA section 111 is the Crude Oil and Natural Gas Production source category. This category is defined in 40 CFR 60.5430a as crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and natural gas production and processing, which includes the well and extend to, but does not include, the point of custody transfer to the natural gas transmission and storage segment.[75] Within this source category, the EPA has set standards of performance (BSER) for individual affected facilities. These affected facilities are the only emission sources within the Crude Oil and Natural Gas Production source category for which these NSPS apply and are defined in 40 CFR 60.5365a.

Specifically, the EPA has defined the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station as individual affected facilities in the rule. Affected facilities are defined at the individual site level, and not as the collection of fugitive emissions components across multiple sites, or a collection of sources within a basin. Further, the standards that apply to these affected facilities are specific to the individual well site or compressor station, as defined in 40 CFR 60.5365a(i) and (j) and 40 CFR 60.5397a. For example, the collection of fugitive emissions components at an existing well site become subject to the fugitive emissions requirements when (1) a new well is drilled at that well site, (2) an existing well at that well site is hydraulically fractured, or (3) an existing well at that well site is hydraulically refractured. In all three cases, the event that triggers the requirements for an existing well site are based on site-specific changes, and not changes at other nearby sites. Drilling a new well at a well site within the same basin, for instance, does not trigger the fugitive emissions requirements for all well sites located in that basin.

When establishing the requirements for the collection of fugitive emissions components, the EPA limited the applicability to individual well sites or compressor stations. The work practice standards set in accordance with section 111(h)(1) of the CAA were established for the collection of fugitive emissions components at an individual well site or compressor station. Since the NSPS does not define the emission source subject to BSER as a basin, or other aggregation of emission points, the EPA finds it inappropriate to evaluate alternatives that seek to implement such a definition. As a practical matter, the EPA concludes that any determination of equivalent emission reductions through an AMEL under section 111(h)(3), or for an alternative work practice under section 111(h)(1), of the CAA for these NSPS should be determined at the same affected facility level (*i.e.,* collection of fugitive emissions components at a well site or at a compressor station) as the original work practice standards.

Similar to the EPA's explanation in the Affordable Clean Energy rule (''ACE''), here the EPA does not need to determine whether it would have reasonable grounds to define ''source'' for purposes of the fugitive emissions monitoring work practice standard as a geographic area, such as a basin. Because these NSPS define an affected facility for this purpose as the collection of fugitive emissions components at a well site, and the collection of fugitive emissions components at a compressor station, the EPA does not think it is appropriate for AMEL applications to accommodate the averaging of emissions.[76]

Second, it is unclear whether the commenters are suggesting that such aggregation would take into account emissions from sources within a basin not subject to these NSPS, such as existing oil and gas well sites or compressor stations, or sources that emit VOC that are included in a different source category. In response to this point, the EPA directs commenters to the discussion of CAA section 111, generation shifting, and emission offsets included in ACE.[77] ''[T]he plain language of CAA section 111 does not authorize the EPA to select as the BSER a system that is premised on application to the source category as a whole or to entities entirely outside the regulated source category.'' [78] This principle also applies in the context of evaluating alternatives to the established BSER.

Lastly, commenters suggest that averaging should be appropriate here because the EPA allows averaging in its BART program. However, that comparison is not appropriate because it fails to consider differences between BART and the BSER for this NSPS. The BART requirement is just one component of a larger strategy to make reasonable progress towards the national goal of remedying visibility impairment in certain areas. The EPA determined in the BART context that if a state can demonstrate that an alternative strategy, such as an emissions trading scheme, will be even more effective at improving visibility, such a ''better-than-BART'' strategy may be adopted to fulfill the role that would otherwise by filled by BART. However, in the context of this NSPS there is less flexibility on this point than in the BART program because, as explained above, there are no other components to reducing emissions aside from the BSER, the BSER is not based on reasonable progress, and this NSPS does not define the emission source subject to BSER as a basin or other aggregation of emission points.

2. State Fugitive Emissions Programs

The EPA received comments related to the alternative fugitive emissions standards on several topics. The comments received by the EPA that resulted in significant rule changes are discussed in section V.C.2 of this preamble, along with our response and rationale for the changes. Specifically, these topics were related to whether the state regulations/requirements determined to be alternative fugitive standards to NSPS subpart OOOOa fugitive requirements will provide adequate coverage of the emission sources in the state and the potential for duplicative reporting and recordkeeping requirements. Further details on comments related to these topics are provided below, along with other significant comments and the EPA's responses. Other comments, and more detailed comments covering the topics discussed in this preamble, related to the state fugitive monitoring programs can be found in the RTC document

[75] See the Review Rule published in the **Federal Register** of Monday, September 14, 2020 and supporting information located at Docket ID No. EPA–HQ–OAR–2017–0757.

[76] See 81 FR 32520, 32556 and 57 (July 8, 2019) (section titled ''Averaging and Trading'').

[77] *Id.* at 32523–26.

[78] *Id.* at 32524.

available in the docket, along with the EPA's responses.

Comment: The EPA proposed alternative fugitive emissions standards based on our determination that certain states had existing requirements equivalent to the proposed fugitive emissions requirements. These determinations were based on qualitative assessments comparing various aspects of the requirements, such as monitoring frequencies and repair deadlines. Two commenters stated that the equivalency determinations must be quantitative if the EPA wants to set alternative standards because they are similar to AMELs. The commenters indicated that the Agency's analysis evaluated whether a state has regulations that are similar to the EPA's regulations, rather than whether the emissions reductions achieved by those regulations are quantitatively equivalent. One of the commenters stated that the EPA's qualitative comparison is legally insufficient because it does not meet the statutory requirement that an applicant "establish" that an AMEL "will achieve" reductions in emissions "at least equivalent to" the reduction achieved under the Federal standards.[79] This commenter stated that, without a quantitative comparison, it is impossible to determine whether an AMEL will achieve at least an equivalent reduction in pollutant emissions. The commenter further notes that past AMEL approvals under this provision were based on detailed quantitative determinations for each facility to determine the exact emissions levels that would be achievable at that facility, and then those levels were compared to the emissions levels achievable under the present NSPS. The commenter stated that the EPA's policy changes in how equivalency is determined are inconsistent with the requirements of section 111(h) of the CAA and also stated that the EPA's approach of "combining . . . aspects of the state requirements to formulate alternatives,"[80] to determine equivalency is not a permissible or reasonable approach. The commenter noted that while some aspects of a state-level program may be more protective than the corresponding Federal requirements, others may not be, and the commenter stated that qualitative comparisons cannot determine the net effects of program elements that point in opposite directions.

Response: The EPA agrees that in some instances when the EPA is evaluating an alternative, it would be preferable to use a quantitative analysis, but we do not agree that such analysis is necessary or prudent in this instance for determining the equivalency of fugitive emissions requirements in state regulations. The CAA does not require the EPA to conduct a quantitative analysis to evaluate an alternative standard or to determine whether that alternative is equivalent to the underlying standard. Work practice standards under section 111(h)(1) of the CAA are set when "it is not feasible to prescribe or enforce a standard of performance." Section 111(h)(2) of the CAA further defines that the phrase not feasible to prescribe or enforce a standard of performance means any situation in which the Administrator determines that: (A) A pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant; or (B) the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations. Fugitive emissions are not quantified within the rule, and the technologies used in this rule to detect fugitive emissions do not quantify the actual emissions that are detected and then remediated through repair. Further, even if direct quantification were possible through the currently approved technologies, those quantified emissions would only represent the fugitive emissions detected on that specific day and would not offer information related to how long those emissions were present prior to detection, or account for any emissions that occur between monitoring surveys. Due to the fact-specific circumstances of the work practice standard in the existing rule, it is not practical for the EPA to conduct an accurate and meaningful quantitative analysis of the alternatives. It is also not necessary for the EPA to conduct a quantitative analysis. The statute does not require a quantitative analysis. Therefore, the most practical way to evaluate the equivalence of a fugitive emissions monitoring and repair program is through the site-specific qualitative comparison that we used. It is the EPA's determination that the analysis, which evaluates the types of components monitored, the frequency of monitoring, the detection instrument, the threshold that triggers repairs, and the repair deadline, is sufficient and appropriate for demonstrating that the six programs identified as alternative fugitive standards are equivalent to the fugitive emissions requirements of NSPS subpart OOOOa.[81] Therefore, we have not conducted a quantitative analysis of the individual state programs that are finalized in this action as alternative standards.

Comment: One commenter performed its own quantitative assessment of the state programs that the EPA proposed as equivalent to NSPS subpart OOOOa with the October 15, 2018, proposal. From this analysis, the commenter stated that it found differences in the applicability thresholds for several of the state programs, which results in the state programs (combined) covering only 34 percent of the total wells that would be covered by the proposal or the 2016 NSPS subpart OOOOa in these states. The commenter also stated that state programs vary in stringency and may not reduce emissions to the same level as the EPA standards, such as the Ohio and Texas provisions that allow for inspection frequency to decrease based on the percentage of components leaking. The commenter asserted that its assessment demonstrates that both the Ohio and Texas programs reduce emissions to a lesser extent than the proposed requirements, while California and Colorado meet the emission reduction levels accomplished by the proposal. Overall, the commenter said that the state programs will achieve a reduction of methane emissions that is 36 percent less than the reduction that would be achieved by the amendments proposed on October 15, 2018. When compared to the 2016 NSPS subpart OOOOa requirements, the commenter said that the state programs would result in 58 percent less emissions reductions. The commenter remarked that these findings demonstrate that these state programs are not equivalent to either the proposal or the 2016 NSPS subpart OOOOa. Another commenter also remarked that the California Air Resources Board has performed a preliminary assessment of state programs against the 2016 NSPS subpart OOOOa and found that only the California, Colorado, Pennsylvania, Utah, and Texas programs (within narrow parameters) are likely to be equivalent.

Response: The EPA reviewed the analysis provided by the commenter but notes that the analysis appears to include an incorrect assumption. Specifically, the commenter stated that only 34 percent of the wells covered by the fugitive emissions requirements in NSPS subpart OOOOa and that are also

[79] See CAA section 111(h)(3).

[80] See 83 FR 52081.

[81] See memorandum, "Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Final Standards at 40 CFR part 60, subpart OOOOa," located at Docket ID No. EPA–HQ–OAR–2017–0483. January 17, 2020.

located in one of the six states with proposed alternative fugitive standards would actually be subject to those alternative fugitive standards. This is not correct. The assumption by the commenter is that the alternative standards are deficient because not all of the sites that are currently subject to NSPS subpart OOOOa would be required to monitor and, thus, reduce fugitive emissions. This assumption is incorrect. The applicability criteria found in NSPS subpart OOOOa will continue to apply regardless of the state's applicability criteria.

Using Texas as an example, the commenters stated that only 5 percent of the sites that are subject to NSPS subpart OOOOa would have monitoring requirements under the alternative fugitive standards for well sites located in Texas. While this percentage may represent those sites in Texas that can utilize the alternative, this does not mean that the other 95 percent of sites escape regulation under the NSPS. If a well site is subject to the Texas standards, then that well site may opt to comply with those State-level standards as an alternative to certain Federal fugitive emissions requirements in NSPS subpart OOOOa. However, if a well site located in Texas is not subject to the State-level requirements and is subject to the NSPS (95 percent of the sites according to the commenter), then the alternative standard would not be available to that site, and monitoring would be required through the requirements in NSPS subpart OOOOa. Put another way, the alternatives included in this final rule do not alter the applicability criteria of the NSPS for any sites. If a well site in Texas was required to comply with the NSPS before the alternative was approved, then that site is still required to comply with the NSPS, but the final rule affords certain sites an alternative way to demonstrate that compliance with the NSPS, if they so choose. Moreover, regardless of whether the site complies with the fugitive emissions requirements in NSPS subpart OOOOa, or the alternative fugitive standards for their state, they must conduct the specific monitoring and repair for the NSPS subpart OOOOa defined fugitive emissions components at a well site or compressor station, as applicable.

Comment: Several commenters asserted that the EPA should recognize the approved state programs as wholly equivalent to the fugitive emissions requirements in the NSPS and fully delegate the implementation of those fugitive emissions requirements to those states, including the states' recordkeeping and reporting requirements. The commenters noted that the EPA is requiring operators to use the fugitive emission component definition from the 2016 NSPS subpart OOOOa and the 2016 NSPS subpart OOOOa reporting and monitoring plan.

Two of the commenters observed that they are required to comply with both the state requirements and Federal fugitive emissions programs concurrently. The commenters stated that complying with two different recordkeeping and reporting schemes for the same site is very burdensome with no added benefit for the environment. Sites that operate where they are subject to both the NSPS and a state program will sometimes be required to keep two very similar sets of records to comply with both standards. Likewise, sites in this situation may be required to report similar overlapping information to both the Federal system and a state system. According to commenters, this overlap in recordkeeping and reporting (and sometimes in monitoring plans) creates redundant work that unnecessarily consumes resources. The commenters go on to assert that requiring the Federal reporting and monitoring plan defeats the purpose and any benefit from the EPA approving state programs and suggest that if a state program is not adequate in the EPA's opinion, then the EPA should address the issue with the individual state, so it can be approved in whole. Commenters added that as an alternative, the EPA could require that the fugitive emissions component definition from NSPS subpart OOOOa be used when following an alternative standard, even if the state program definitions differ, but the EPA should not require any duplicative administrative burden.

Further, the commenters stated that CAA Section 111 fits squarely within the cooperative federalism tradition, with CAA section 111(c) expressly calling on states to develop ''a procedure for implementing and enforcing standards of performance for new sources'' and calling on the Administrator to delegate ''any authority he has . . . to implement and enforce such standards.'' [82] Two commenters noted that the EPA did not evaluate the equivalency of state reporting requirements or monitoring plans and, thus, did not propose any alternative standards for these aspects of the NSPS subpart OOOOa fugitive emissions requirements. These commenters stated that the exclusion of state reporting and monitoring plan requirements from the EPA's equivalency evaluation leaves the regulated community in certain states subject to potentially duplicative regulation.

[82] See CAA section 111(c)(1).

Response: It is unclear to the EPA what commenters mean by ''wholly equivalent'' and ''fully delegate,'' but we are providing a response based on our interpretation that commenters are requesting approved alternative standards only require recordkeeping and reporting to the individual states and not to the EPA. After considering the comments provided, the EPA reviewed the recordkeeping and reporting requirements for each of the six states that were proposed for alternative fugitive standards in the October 15, 2018, proposal (California, Colorado, Ohio, Pennsylvania, Texas, and Utah). For California, Ohio, and Pennsylvania, the EPA was able to identify site-specific reporting requirements in the state reports which, while not identical to the reporting for NSPS subpart OOOOa, were determined to be appropriate to demonstrate compliance with the alternative fugitive standards for those states. Therefore, in this final rule, we are allowing well sites and compressor stations located in California, Ohio, and Pennsylvania that adopt the alternative fugitive standards to electronically submit a copy of the report that is submitted to their state as specified in 40 CFR 60.5420a(b)(7)(iii). As discussed in section V.C of this preamble, this report must be submitted in the format in which it was submitted to the state, noting the following order of preference: (1) As a binary file, (2) as a XML schema, (3) as a searchable PDF, or (4) as a scanned PDF of a hard copy.

In reviewing the reporting requirements for Colorado, we noted that the report is a fillable form to the state that summarizes all monitoring events for that year at the company-level. Therefore, no site-specific information is available. We then reviewed the recordkeeping forms for Colorado to identify what information is required for the individual sites and compared that information to the required annual report for NSPS subpart OOOOa. We identified one recordkeeping element required by NSPS subpart OOOOa that was not already included in the recordkeeping requirements for Colorado: Deviations from certain requirements in the monitoring plan. Given that the Federal monitoring plan, and deviations from that plan, are still required for all sites that adopt the alternative fugitive standards, there are no additional recordkeeping elements that would be needed beyond what the State already requires. While the EPA has determined that the Colorado program for fugitive emissions requirements is an acceptable alternative to NSPS subpart OOOOa, the company-level reports in Colorado are insufficient to demonstrate compliance for individual sites. Therefore, we are still requiring that well sites and compressor stations located in Colorado that adopt the alternative fugitive standard must report the information required by NSPS subpart OOOOa for fugitive emissions components at well sites and compressor stations.

Our review of the Texas reporting requirements found that sites only report information when fugitive emissions are found. While this may be appropriate for demonstrating compliance to the State, it is not adequate information for the EPA to ensure compliance with the alternative fugitive standards for well sites and compressor stations located in Texas. Similar to Colorado, we examined the recordkeeping requirements and found that sites located in the State are already required by the State to keep records that facilitate the reporting required by NSPS subpart OOOOa for fugitive emissions components at well sites and compressor stations. Therefore, we are requiring that well sites and compressor stations located in Texas that adopt the alternative fugitive standards must report the information required in NSPS subpart OOOOa.

Finally, the requirements in Utah do not include reporting. Similar to Colorado and Texas, we reviewed the recordkeeping requirements. For Utah, sites must keep records of the monitoring plan and the monitoring surveys. We found these records are similar to the information that is required in the NSPS subpart OOOOa report for fugitive emissions components and would not require additional recordkeeping. Therefore, we are requiring that well sites located in Utah that adopt the alternative fugitive standards must report the information required in NSPS subpart OOOOa.

VII. Impacts of These Final Amendments

A. What are the air impacts?

The EPA projected that, from 2021 to 2030, relative to the baseline, the final rule will forgo about 450,000 short tons of methane emissions reductions (10 million tons CO_2 Eq.), 120,000 short tons of VOC emissions reductions, and 4,700 short tons of HAP emission reductions from facilities affected by this reconsideration. The EPA estimated regulatory impacts beginning in 2021 as it is the first full year of implementation of this rule. The EPA estimated impacts through 2030 to illustrate the accumulating effects of this rule over a longer period. The EPA did not estimate impacts after 2030 for reasons including limited information, as explained in the RIA.

B. What are the energy impacts?

There will likely be minimal change in emissions control energy requirements resulting from this rule. Additionally, this final action continues to encourage the use of emission controls that recover hydrocarbon products that can be used on-site as fuel or reprocessed within the production process for sale. The energy impacts described in this section are those energy requirements associated with the operation of emission control devices. Potential impacts on the national energy economy from the rule are discussed in the economic impacts section.

C. What are the compliance cost reductions?

The PV of the regulatory compliance cost reduction associated with this final rule over the 2021 to 2030 period was estimated to be $800 million (in 2016 dollars) using a 7-percent discount rate and $1.0 billion using a 3-percent discount rate. The EAV (rounded to two significant figures) of these cost reductions is estimated to be $110 million per year using either a 7-percent or 3-percent discount rate.

These estimates do not, however, include the forgone producer revenues associated with the decrease in the recovery of saleable natural gas, though some of the compliance actions required in the baseline would likely have captured saleable product that would have otherwise been emitted to the atmosphere. Estimates of the value of the recovered product were included in previous regulatory analyses as offsetting compliance costs. Because of the deregulatory nature of this final action, the EPA projected a reduction in the recovery of saleable product. Using the 2020 Annual Energy Outlook (AEO) projection of natural gas prices to estimate the value of the change in the recovered gas at the wellhead projected to result from the final action, the EPA estimated a PV of regulatory compliance cost reductions of the final rule over the 2021 to 2030 period of $750 million using a 7-percent discount rate and $950 million using a 3-percent discount rate. The corresponding estimates of the EAV of cost reductions after accounting for the forgone revenues were $100 million per year using a 7-percent discount rate and $110 million per year using a 3-percent discount rate.

D. What are the economic and employment impacts?

The EPA used the National Energy Modeling System (NEMS) to estimate the impacts of the 2016 NSPS subpart OOOOa on the U.S. energy system. The NEMS is a publicly available model of the U.S. energy economy developed and maintained by the U.S. Energy Information Administration and is used to produce the AEO, a reference publication that provides detailed projections of the U.S. energy economy. The EPA estimated small impacts on crude oil and natural gas markets of the 2016 NSPS subpart OOOOa rule over the 2020 to 2025 period. This final rule will result in a decrease in total compliance costs relative to the baseline. Therefore, the EPA expects that this rule will partially reduce the impacts estimated for the 2016 NSPS subpart OOOOa in the 2016 NSPS subpart OOOOa RIA.

Executive Order 13563 directs Federal agencies to consider the effect of regulations on job creation and employment. According to the Executive order, ‘‘our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation. It must be based on the best available science.’’ (Executive Order 13563, 2011). While a standalone analysis of employment impacts is not included in a standard benefit-cost analysis, such an analysis is of concern in the current economic climate given continued interest in the employment impact of regulations such as this final rule. The EPA estimated the changes in compliance-related labor impacts due to the changes finalized in this rule. As presented in the RIA for this action, the EPA projected there will be reductions in the labor required for compliance-related activities associated with the 2016 NSPS subpart OOOOa requirements relating to fugitive emissions monitoring and certifications of CVS.

E. What are the forgone benefits?

The EPA expects forgone climate and health benefits due to the forgone emissions reductions projected under this final rule. The EPA estimated the forgone domestic climate benefits from the forgone methane emissions reductions using an interim measure of the domestic social cost of methane (SC-CH_4). The SC-CH_4 estimates used here were developed under Executive Order 13783 for use in regulatory analyses until an improved estimate of the impacts of climate change to the U.S.

can be developed based on the best available science and economics. Executive Order 13783 directed agencies to ensure that estimates of the social cost of GHG used in regulatory analyses ''are based on the best available science and economics'' and are consistent with the guidance contained in Office of Management and Budget (OMB) Circular A–4, ''including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates'' (Executive Order 13783, Section 5(c)). In addition, Executive Order 13783 withdrew the TSDs and the August 2016 Addendum to these TSDs describing the global social cost of GHG estimates developed under the prior Administration as no longer representative of government policy. The withdrawn TSDs and Addendum were developed by an interagency working group that included the EPA and other executive branch entities and were used in the 2016 NSPS subpart OOOOa RIA.

The EPA estimated the PV of the forgone domestic climate benefits over the 2021 to 2030 period to be $19 million under a 7-percent discount rate and $71 million under a 3-percent discount rate. The EAV of these forgone benefits is estimated $2.5 million per year under a 7-percent discount rate and $8.1 million per year under a 3-percent discount rate. These values represent only a partial accounting of domestic climate impacts from methane emissions and do not account for health effects of ozone exposure from the increase in methane emissions.

Under the final rule, the EPA expects that forgone VOC emission reductions will degrade air quality and are likely to adversely affect health and welfare associated with exposure to ozone, $PM_{2.5}$, and HAP, but we did not quantify these effects at this time due to the data limitations described below. This omission should not imply that these forgone benefits may not exist; rather, it reflects the inherent difficulties in accurately modeling the direct and indirect impacts of the projected reductions in emissions for this industrial sector. To the extent that the EPA were to quantify these ozone and PM impacts, it would estimate the number and value of avoided premature deaths and illnesses using an approach detailed in the Particulate Matter NAAQS and Ozone NAAQS RIAs.[83] [84] This approach relies on full-form air quality modeling. The Agency is committed to assessing ways of conducting full-form air quality modeling for the oil and natural gas sector that would be suitable for use in regulatory analysis in the context of NSPS, including ways to address the uncertainties regarding the scope and magnitude of VOC emissions.

When quantifying the incidence and economic value of the human health impacts of air quality changes, the Agency sometimes relies upon alternative approaches to using full-form air quality modeling, called reduced-form techniques, often reported as ''benefit-per-ton'' values that relate air pollution impacts to changes in air pollutant precursor emissions.[85] A small, but growing, literature characterizes the air quality and health impacts from the oil and natural gas sector.[86] [87] [88] The Agency feels more work needs to be done to vet the analysis and methodologies for all potential approaches for valuing the health effects of VOC emissions before they are used in regulatory analysis, but is committed to continuing this work. Recently, the EPA systematically compared the changes in benefits, and concentrations where available, from its benefit-per-ton technique and other reduced-form techniques to the changes in benefits and concentrations derived from full-form photochemical model representation of a few different specific emissions scenarios.[89] The Agency's goal was to create a methodology by which investigators could better understand the suitability of alternative reduced-form air quality modeling techniques for estimating the health impacts of criteria pollutant emissions changes in the EPA's benefit-cost analysis, including the extent to which reduced form models may over- or under-estimate benefits (compared to full-scale modeling) under different scenarios and air quality concentrations. The EPA Science Advisory Board (SAB) recently convened a panel to review this report.[90] In particular, the SAB will assess the techniques the Agency used to appraise these tools; the Agency's approach for depicting the results of reduced-form tools; and, steps the Agency might take for improving the reliability of reduced-form techniques for use in future RIAs.

VIII. Statutory and Executive Order Reviews

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

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

This action is an economically significant regulatory action that was submitted to OMB for review. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This RIA is available in the docket. The RIA describes in detail the basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below.

Table 6 shows the present value and equivalent annualized value of the costs, benefits, and net benefits of the final rule for the 2021 to 2030 period relative to the baseline using discount rates of 7 and 3 percent, respectively. The table also shows the total forgone emission reductions projected from 2021 to 2030 relative to the baseline. In the following table, we refer to the compliance cost reductions as the ''benefits'' and the forgone benefits as the ''costs'' of this final action. The net benefits are the benefits (total cost

[83] U.S. EPA. December 2012. ''Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter.'' EPA–452/R–12–005. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. *https://www3.epa.gov/ttnecas1/regdata/RIAs/finalria.pdf.* Accessed January 9, 2020.

[84] U.S. U.S. EPA. September 2015. ''Regulatory Impact Analysis of the Final Revisions to the National Ambient Air Quality Standards for Ground-Level Ozone.'' EPA–452/R–15–007. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. *https://www3.epa.gov/ttnecas1/docs/20151001ria.pdf.* Accessed January 9, 2020.

[85] U.S. EPA. 2018. ''Technical Support Document: Estimating the Benefit per Ton of Reducing $PM_{2.5}$ Precursors from 17 Sectors.'' February. *https://www.epa.gov/sites/production/files/2018-02/documents/sourceapportionmentbpttsd_2018.pdf.* Accessed January 9, 2020.

[86] Fann, N., K.R. Baker, E.A.W. Chan, A. Eyth, A. Macpherson, E. Miller, and J. Snyder. 2018. ''Assessing Human Health $PM_{2.5}$ and Ozone Impacts from U.S. Oil and Natural Gas Sector Emissions in 2025.'' Environmental Science and Technology 52(15):8095–8103.

[87] Litovitz, A., A. Curtright, S. Abramzon, N. Burger, and C. Samaras. 2013. ''Estimation of Regional Air-Quality Damages from Marcellus Shale Natural Gas Extraction in Pennsylvania.'' Environmental Research Letters 8(1), 014017.

[88] Loomis, J. and M. Haefele. 2017. ''Quantifying Market and Non-market Benefits and Costs of Hydraulic Fracturing in the United States: A Summary of the Literature.'' Ecological Economics 138:160–167.

[89] This analysis compared the benefits estimated using full-form photochemical air quality modeling simulations (CMAQ and CAMx) against four reduced-form tools, including: InMAP; AP2/3; EASIUR and the EPA's benefit-per-ton.

[90] 85 FR 23823 (April 29, 2020).

reductions) minus the costs (forgone domestic climate benefits).

TABLE 6—SUMMARY OF THE PRESENT VALUE AND EQUIVALENT ANNUALIZED VALUE OF THE MONETIZED FORGONE BENEFITS, COST REDUCTIONS, AND NET BENEFITS FROM 2021 TO 2030, 7-PERCENT AND 3-PERCENT DISCOUNT RATES

[Millions of 2016$]

	7-Percent discount rate		3-Percent discount rate	
	PV	EAV	PV	EAV
Benefits (Total Cost Reductions)	$750	$100	$950	$110
Compliance Cost Reductions	*800*	*110*	*1,000*	*110*
Forgone Value of Product Recovery	*44*	*5.9*	*57*	*6.5*
Costs (Forgone Domestic Climate Benefits)	19	2.5	71	8.1
Net Benefits	730	97	880	100
Non-monetized Forgone Benefits	Non-monetized climate impacts from increases in methane emissions. Health effects of $PM_{2.5}$ and ozone exposure from an increase of about 120,000 short tons of VOC from 2021 through 2030. Health effects of HAP exposure from an increase of about 4,700 short tons of HAP from 2021 through 2030. Health effects of ozone exposure from an increase of about 450,000 short tons of methane from 2021 through 2030. Visibility impairment. Vegetation effects.			

Note: Estimates are rounded to two significant digits and may not sum due to independent rounding.

B. Executive Order 13771: Reducing Regulations and Controlling Regulatory Costs

This action is considered an Executive Order 13771 deregulatory action. Details on the estimated cost reductions of this final rule can be found in the EPA's analysis of the potential costs and benefits associated with this action.

C. Paperwork Reduction Act (PRA)

The information collection activities in this rule have been submitted for approval to the OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2523.04, Control Number 2060–0721. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

A summary of the information collection activities previously submitted to the OMB for the final action titled ''Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced After September 18, 2015'' (2016 NSPS subpart OOOOa), under the PRA, and assigned OMB Control Number 2060–0721, can be found at 81 FR 35890. You can find a copy of the 2016 ICR in the 2016 NSPS subpart OOOOa docket (EPA–HQ–OAR–2010–0505–7626). The EPA is revising the information collection activities as a result of the amendments in this final rule. You can find a copy of the revised ICR in the docket for this rule (EPA–HQ–OAR–2017–0483), and it is briefly summarized here.

Comments were received on the October 15, 2018 (83 FR 52056) proposed rulemaking indicating that the recordkeeping and reporting burden for the 2016 NSPS subpart OOOOa was significantly underestimated, as discussed in section V.B.2 of this preamble. After consideration of these comments, the EPA updated the assessment of the recordkeeping and reporting burden for the 2016 NSPS subpart OOOOa. The updated 2016 NSPS subpart OOOOa ICR was used as the ''baseline'' from which changes in the Review Rule published in the **Federal Register** of Monday, September 14, 2020 were compared. Additional information on the Review Rule can be found at Docket ID No. EPA–HQ–OAR–2017–0757.

This final rule includes additional revisions to the information collection activities for NSPS subpart OOOOa.

Respondents/affected entities: Owners or operators of onshore oil and natural gas affected facilities.

Respondent's obligation to respond: Mandatory.

Estimated number of respondents: 519.

Frequency of response: Annually or semiannually, depending on the requirement.

Total estimated burden: 1,124,965 hours. Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $215,874,903, includes $2,681,370 annualized capital or operation and maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

D. 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. This is a deregulatory action, and the burden on all entities affected by this final rule, including small entities, is reduced compared to the 2016 NSPS subpart

OOOOa. See the RIA for details. We have, therefore, concluded that this action will relieve regulatory burden for all directly regulated small entities.

E. Unfunded Mandates Reform Act (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. The action imposes no enforceable duty on any state, local, or tribal governments, or the private sector.

F. 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.

G. 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 effects 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.

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

This action is not subject to Executive Order 13045 because the EPA does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. While children may experience forgone benefits as a result of this action, the potential forgone emission reductions (and related benefits) from the final amendments are small compared to the overall emission reductions (and related benefits) from the 2016 NSPS subpart OOOOa.

This final action does not affect the level of public health and environmental protection already being provided by existing NAAQS and other mechanisms in the CAA. This action does not affect applicable local, state, or Federal permitting or air quality management programs that will continue to address areas with degraded air quality and maintain the air quality in areas meeting current standards. Areas that need to reduce criteria air pollution to meet the NAAQS will still need to rely on control strategies to reduce emissions. The EPA does not believe this decrease in emission reductions projected from this action will have a disproportionate adverse effect on children's health.

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

This action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. In the RIA accompanying the 2016 NSPS subpart OOOOa, the EPA used the NEMS to estimate the impacts of the 2016 NSPS subpart OOOOa on the United States energy system. The EPA estimated small impacts of that rule over the 2020 to 2025 period relative to the baseline for that rule. This final rule is estimated to result in a decrease in total compliance costs, with the reduction in costs affecting a subset of the affected entities under NSPS subpart OOOOa. Therefore, the EPA expects that this deregulatory action will reduce the impacts estimated for the final NSPS in the 2016 RIA and, as such, is not a significant energy action.

J. National Technology Transfer and Advancement Act (NTTAA)

This action involves technical standards.[91] Therefore, the EPA conducted searches for the Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration through the Enhanced National Standards Systems Network (NSSN) Database managed by the American National Standards Institute (ANSI). Searches were conducted for EPA Methods 1, 1A, 2, 2A, 2C, 2D, 3A, 3B, 3C, 4, 6, 10, 15, 16, 16A, 18, 21, 22, and 25A of 40 CFR part 60, appendix A. No applicable voluntary consensus standards (VCS) were identified for EPA Methods 1A, 2A, 2D, 21, and 22 and none were brought to its attention in comments. All potential standards were reviewed to determine the practicality of the VCS for this rule.

Two VCS were identified as an acceptable alternative to the EPA test methods for the purpose of this rule. First, ANSI/ASME PTC 19–10–1981, ''Flue and Exhaust Gas Analyses (Part 10),'' was identified to be used in lieu of EPA Methods 3B, 6, 6A, 6B, 15A, and 16A manual portions only and not the instrumental portion. This standard includes manual and instructional methods of analysis for carbon dioxide, carbon monoxide, hydrogen sulfide, nitrogen oxides, oxygen, and SO_2. Second, ASTM D6420–99 (2010), ''Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry,'' is an acceptable alternative to EPA Method 18 with the following caveats; only use when the target compounds are all known and the target compounds are all listed in ASTM D6420 as measurable. ASTM D6420 should never be specified as a total VOC Method. (ASTM D6420–99 (2010) is not incorporated by reference in 40 CFR part 60.) The search identified 19 VCS that were potentially applicable for this rule in lieu of the EPA reference methods. However, these have been determined to not be practical due to lack of equivalency, documentation, validation of data, and other important technical and policy considerations. For additional information, please see the memorandum, ''Voluntary Consensus Standard Results for Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration,'' located at Docket ID No. EPA–HQ–OAR–2017–0483.

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

The EPA believes that this action does not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations, and/or indigenous peoples, as specified in Executive Order 12898 (59 FR 7629, February 16, 1994). While these communities may experience forgone benefits as a result of this action, the potential forgone emission reductions (and related benefits) from the final amendments are small compared to the overall emission reductions (and related benefits) from the 2016 NSPS subpart OOOOa. The amendments in this final action will decrease the projected emission reductions of the rule it revises by a small degree. Based on the revisions in this final rule, for the year 2025, we estimate a decrease in the projected emissions reductions anticipated by the 2016 NSPS subpart OOOOa in the production and processing segments of about 12 to 15 percent for methane and about 7 to 9 percent for VOC.

[91] These technical standards are the same as those previously finalized at 40 CFR part 60, subpart OOOOa (81 FR 35824). 2016 NSPS subpart OOOOa also previously incorporated by reference 10 technical standards. The incorporation by reference remains unchanged in this action. See Docket ID Item Nos. EPA–HQ–OAR–2010–0505–7657 and EPA–HQ–OAR–2010–0505–7658.

Moreover, this action does not affect the level of public health and environmental protection already being provided by existing NAAQS, including ozone and $PM_{2.5}$, and other mechanisms in the CAA. This action does not affect applicable local, state, or Federal permitting or air quality management programs that will continue to address areas with degraded air quality and maintain the air quality in areas meeting current standards. Areas that need to reduce criteria air pollution to meet the NAAQS will still need to rely on control strategies to reduce emissions.

L. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 60

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

Andrew Wheeler,

Administrator.

For the reasons set out in the preamble, 40 CFR part 60 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 OOOOa—Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After September 18, 2015

■ 2. Section 60.5360a is amended by revising paragraph (a) to read as follows:

§ 60.5360a What is the purpose of this subpart?

(a) This subpart establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from affected facilities in the crude oil and natural gas production source category that commence construction, modification, or reconstruction after September 18, 2015.

* * * * *

■ 3. Section 60.5365a is amended by revising paragraphs (e), (f) introductory text, (g) introductory text, and (g)(1) and adding paragraph (i)(4) to read as follows:

§ 60.5365a Am I subject to this subpart?

* * * * *

(e) Each storage vessel affected facility, which is a single storage vessel as specified in paragraph (e)(1), (2), or (3) of this section.

(1) A single storage vessel that commenced construction, reconstruction, or modification after September 18, 2015, and on or before November 16, 2020, is a storage vessel affected facility if its potential for VOC emissions is equal to or greater than 6 tons per year (tpy) as determined according to this paragraph (e)(1). The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput (as defined in § 60.5430a) determined for a 30-day period prior to the applicable emission determination deadline specified in paragraphs (e)(2)(i) and (ii) of this section, except as provided in paragraph (e)(5)(iv). The determination may take into account requirements under a legally and practicably enforceable limit in an operating permit or other requirement established under a Federal, state, local, or tribal authority.

(2) Except as specified in paragraph (e)(3) of this section, a single storage vessel that commenced construction, reconstruction or modification after November 16, 2020, is a storage vessel affected facility if the potential for VOC emissions is equal to or greater than 6 tpy as determined according to paragraph (e)(2)(i) or (ii) of this section, except as provided in paragraph (e)(5)(iv) of this section. The determination may take into account requirements under a legally and practicably enforceable limit in an operating permit or other requirement established under a Federal, state, local, or tribal authority. The potential for VOC emissions is calculated on an individual storage vessel basis and is not averaged across the number of storage vessels at the site.

(i) For each storage vessel receiving liquids pursuant to the standards for well affected facilities in § 60.5375a, including wells subject to § 60.5375a(f), you must determine the potential for VOC emissions within 30 days after startup of production of the well, except as provided in paragraph (e)(5)(iv) of this section. The potential for VOC emissions must be calculated for each individual storage vessel using a generally accepted model or calculation methodology, based on the maximum average daily throughput, as defined in § 60.5430a, determined for a 30-day period of production.

(ii) For each storage vessel located at a compressor station or onshore natural gas processing plant, you must determine the potential for VOC emissions prior to startup of the compressor station or onshore natural gas processing plant using either method described in paragraph (e)(2)(ii)(A) or (B) of this section.

(A) Determine the potential for VOC emissions using a generally accepted model or calculation methodology and based on the throughput established in a legally and practicably enforceable limit in an operating permit or other requirement established under a Federal, state, local, or tribal authority; or

(B) Determine the potential for VOC emissions using a generally accepted model or calculation methodology and based on projected maximum average daily throughput. Maximum average daily throughput is determined using a generally accepted engineering model (*e.g.,* volumetric condensate rates from the storage vessels based on the maximum gas throughput capacity of each producing facility) to project the maximum average daily throughput for the storage vessel.

(3) If a storage vessel battery, which consists of two or more storage vessels, meets all of the design and operational criteria specified in paragraphs (e)(3)(i) through (iv) of this section through legally and practicably enforceable standards in a permit or other requirement established under Federal, state, local, or tribal authority, then each storage vessel in such storage vessel battery is a storage vessel affected facility.

(i) The storage vessels must be manifolded together with piping such that all vapors are shared among the headspaces of the storage vessels;

(ii) The storage vessels must be equipped with a closed vent system that is designed, operated, and maintained to route the vapors back to the process or to a control device;

(iii) The vapors collected in paragraph (e)(3)(i) of this section must be routed back to the process or to a control device that reduces VOC emissions by at least 95.0 percent; and

(iv) The VOC emissions, averaged across the number of storage vessels in the battery meeting all of the criteria of paragraphs (e)(3)(i) through (iii) of this section, are equal to or greater than 6 tpy.

(v) If a storage vessel battery meeting all of the criteria specified in paragraphs (e)(3)(i) through (iii) of this section through legally and practicably enforceable standards in a permit or other requirements established under Federal, state, local, or tribal authority, emits less than 6 tpy of VOC emissions averaged across the number of storage vessels in the battery, none of the storage vessels in the battery are storage vessel affected facilities.

(4) 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.

(5) 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 potential for VOC emissions for purposes of determining affected facility status, provided you comply with the requirements in paragraphs (e)(5)(i) through (iv) of this section.

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

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

(iii) You must maintain records that document compliance with paragraphs (e)(5)(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)(5)(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.

(6) The requirements of this paragraph (e)(6) apply to each storage vessel affected facility immediately upon startup, startup of production, or return to service. A storage vessel affected facility that is reconnected to the original source of liquids is a storage vessel affected facility subject to the same requirements that applied before being removed from service. Any storage vessel that is used to replace any storage vessel affected facility is subject to the same requirements that applied to the storage vessel affected facility being replaced.

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

(f) The group of all equipment within a process unit at an onshore natural gas processing plant is an affected facility.

* * * * *

(g) Sweetening units located at onshore natural gas processing plants that commenced construction, modification, or reconstruction after September 18, 2015, and on or before November 16, 2020, and sweetening units that commence construction, modification, or reconstruction after November 16, 2020.

(1) Each sweetening unit that processes natural gas produced from either onshore or offshore wells is an affected facility; and

* * * * *

(i) * * *

(4) For purposes of § 60.5397a, a ''modification'' to an existing source separate tank battery surface site occurs when:

(i) Any of the actions in paragraphs (i)(3)(i) through (iii) of this section occurs at an existing source separate tank battery surface site;

(ii) A well sending production to an existing source separate tank battery site is modified, as defined in paragraphs (i)(3)(i) through (iii) of this section; or

(iii) A well site subject to the requirements in § 60.5397a removes all major production and processing equipment, as defined in § 60.5430a, such that it becomes a wellhead only well site and sends production to an existing source separate tank battery surface site.

* * * * *

■ 4. Section 60.5375a is amended by revising paragraphs (a)(1)(i), (a)(1)(iii) introductory text, and (f)(3)(ii) and adding paragraph (f)(4) to read as follows:

§ 60.5375a What VOC standards apply to well affected facilities?

* * * * *

(a) * * *

(1) * * *

(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. The separator may be a production separator, but the production separator also must be designed to accommodate flowback. Any gas present in the initial flowback stage is not subject to control under this section.

* * * * *

(iii) You must have the separator onsite or otherwise available for use at a centralized facility or well pad that services the well affected facility during well completions. The separator must be available and ready for use to comply with paragraph (a)(1)(ii) of this section during the entirety of the flowback period, except as provided in paragraphs (a)(1)(iii)(A) through (C) of this section.

* * * * *

(f) * * *

(3) * * *

(ii) Route all flowback into one or more well completion vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the flowback before the separator can function is not subject to control under this section. Capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost, or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

(4) You must submit the notification as specified in § 60.5420a(a)(2), submit annual reports as specified in § 60.5420a(b)(1) and (2) and maintain records specified in § 60.5420a(c)(1)(iii) for each wildcat and delineation well. You must submit the notification as specified in § 60.5420a(a)(2), submit annual reports as specified in § 60.5420a(b)(1) and (2), and maintain records as specified in § 60.5420a(c)(1)(iii) and (vii) for each low pressure well.

* * * * *

■ 5. Section 60.5385a is amended by revising paragraph (a)(1) to read as follows:

§ 60.5385a What VOC standards apply to reciprocating compressor affected facilities?

* * * * *

(a) * * *

(1) On or before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of your reciprocating compressor affected facility, August 2, 2016, or the date of the most recent reciprocating compressor rod packing replacement, whichever is latest.

* * * * *

■ 6. Section 60.5393a is amended by revising paragraphs (b) and (c) and removing paragraph (f) to read as follows:

§ 60.5393a What VOC standards apply to pneumatic pump affected facilities?

* * * * *

(b) For each pneumatic pump affected facility at a well site you must reduce natural gas emissions by 95.0 percent, except as provided in paragraphs (b)(3), (4), and (5) of this section.

(1)–(2) [Reserved]

(3) You are not required to install a control device solely for the purpose of complying with the 95.0 percent reduction requirement of paragraph (b) of this section. If you do not have a control device installed on site by the compliance date and you do not have the ability to route to a process, then you must comply instead with the provisions of paragraphs (b)(3)(i) and (ii) of this section. For the purposes of this section, boilers and process heaters are not considered control devices. In addition, routing emissions from pneumatic pump discharges to boilers and process heaters is not considered routing to a process.

(i) Submit a certification in accordance with § 60.5420a(b)(8)(i)(A) in your next annual report, certifying that there is no available control device or process on site and maintain the records in § 60.5420a(c)(16)(i) and (ii).

(ii) If you subsequently install a control device or have the ability to route to a process, you are no longer required to comply with paragraph (b)(3)(i) of this section and must submit the information in § 60.5420a(b)(8)(ii) in your next annual report and maintain the records in § 60.5420a(c)(16)(i), (ii), and (iii). You must be in compliance with the requirements of paragraph (b) of this section within 30 days of startup of the control device or within 30 days of the ability to route to a process.

(4) If the control device available on site is unable to achieve a 95-percent reduction and there is no ability to route the emissions to a process, you must still route the pneumatic pump affected facility's emissions to that control device. If you route the pneumatic pump affected facility to a control device installed on site that is designed to achieve less than a 95-percent reduction, you must submit the information specified in § 60.5420a(b)(8)(i)(C) in your next annual report and maintain the records in § 60.5420a(c)(16)(iii).

(5) If an owner or operator determines, through an engineering assessment, that routing a pneumatic pump to a control device or a process is technically infeasible, the requirements specified in paragraphs (b)(5)(i) through (iv) of this section must be met.

(i) The owner or operator shall conduct the assessment of technical infeasibility in accordance with the criteria in paragraph (b)(5)(iii) of this section and have it certified by either a qualified professional engineer or an in-house engineer with expertise on the design and operation of the pneumatic pump in accordance with paragraph (b)(5)(ii) of this section.

(ii) The following certification, signed and dated by the qualified professional engineer or in-house engineer, shall state: ''I certify that the assessment of technical infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted and this report was prepared pursuant to the requirements of § 60.5393a(b)(5)(iii). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete.''

(iii) The assessment of technical infeasibility to route emissions from the pneumatic pump to an existing control device onsite or to a process shall include, but is not limited to, safety considerations, distance from the control device or process, pressure losses and differentials in the closed vent system, and the ability of the control device or process to handle the pneumatic pump emissions which are routed to them. The assessment of technical infeasibility shall be prepared under the direction or supervision of the qualified professional engineer or in-house engineer who signs the certification in accordance with paragraph (b)(5)(ii) of this section.

(iv) The owner or operator shall maintain the records specified in § 60.5420a(c)(16)(iv).

(6) If the pneumatic pump is routed to a control device or a process and the control device or process is subsequently removed from the location or is no longer available, you are no longer required to be in compliance with the requirements of paragraph (b) of this section, and instead must comply with paragraph (b)(3) of this section and report the change in the next annual report in accordance with § 60.5420a(b)(8)(ii).

(c) If you use a control device or route to a process to reduce emissions, you must connect the pneumatic pump affected facility through a closed vent system that meets the requirements of §§ 60.5411a(d) and (e), 60.5415a(b)(3), and 60.5416a(d).

* * * * *

■ 7. Section 60.5395a is amended by revising the introductory text to read as follows:

§ 60.5395a What VOC standards apply to storage vessel affected facilities?

Each storage vessel affected facility must comply with the VOC standards in this section, except as provided in paragraph (e) of this section.

* * * * *

■ 8. Section 60.5397a is amended by revising paragraphs (a), (c)(2), (c)(7)(i) introductory text, and (c)(8) introductory text, adding paragraph (c)(8)(iii), and revising paragraphs (d), (f), (g) introductory text, (g)(1), (2), and (5), and (h) to read as follows:

§ 60.5397a What fugitive emissions VOC standards apply to the affected facility which is the collection of fugitive emissions components at a well site and the affected facility which is the collection of fugitive emissions components at a compressor station?

* * * * *

(a) You must comply with paragraph (a)(1) of this section, unless your affected facility under § 60.5365a(i) (*i.e.,* the collection of fugitive emissions components at a well site) meets the conditions specified in either paragraph (a)(1)(i) or (ii) of this section. If your affected facility under § 60.5365a(i) (*i.e.,* the collection of fugitive emissions components at a well site) meets the conditions specified in either paragraph (a)(1)(i) or (ii) of this section, you must comply with either paragraph (a)(1) or (2) of this section.

(1) You must monitor all fugitive emission components, as defined in § 60.5430a, in accordance with paragraphs (b) through (g) of this section. You must repair all sources of fugitive emissions in accordance with paragraph (h) of this section. You must keep records in accordance with paragraph (i) of this section and report in accordance with paragraph (j) of this section. For purposes of this section, fugitive emissions are defined as any visible emission from a fugitive emissions component observed using optical gas imaging or an instrument reading of 500 parts per million (ppm) or greater using Method 21 of appendix A–7 to this part.

(i) *First 30-day production.* For the collection of fugitive emissions components at a well site, where the total production of the well site is at or below 15 barrels of oil equivalent (boe) per day for the first 30 days of production, according to § 60.5415a(j), you must comply with the provisions of either paragraph (a)(1) or (2) of this section. Except as provided in this paragraph (a)(1)(i), the calculation must be performed within 45 days of the end of the first 30 days of production. To convert gas production to equivalent barrels of oil, divide the cubic feet of gas produced by 6,000. For well sites that commenced construction, reconstruction, or modification between

October 15, 2019, and November 16, 2020, the owner or operator may use the records of the first 30 days of production after becoming subject to this subpart, if available, to determine if the total well site production is at or below 15 boe per day, provided this determination is completed by December 14, 2020.

(ii) *Well site production decline.* For the collection of fugitive emissions components at a well site, where, at any time, the total production of the well site is at or below 15 boe per day based on a rolling 12-month average, you must comply with the provisions of either paragraph (a)(1) or (2) of this section. To convert gas production to equivalent barrels of oil, divide the cubic feet of gas produced by 6,000.

(2) You must maintain the total production for the well site at or below 15 boe per day based on a rolling 12-month average, according to §§ 60.5410a(k) and 60.5415a(i), comply with the reporting requirements in § 60.5420a(b)(7)(i)(C), and the recordkeeping requirements in § 60.5420a(c)(15)(ii), until such time that you perform any of the actions in paragraphs (a)(2)(i) through (v) of this section. If any of the actions listed in paragraphs (a)(2)(i) through (v) of this section occur, you must comply with paragraph (a)(3) of this section.

(i) A new well is drilled at the well site;

(ii) A well at the well site is hydraulically fractured;

(iii) A well at the well site is hydraulically refractured;

(iv) A well at the well site is stimulated in any manner for the purpose of increasing production, including well workovers; or

(v) A well at the well site is shut-in for the purpose of increasing production from the well.

(3) You must determine the total production for the well site for the first 30 days after any of the actions listed in paragraphs (a)(2)(i) through (v) of this section is completed, according to § 60.5415a(j), comply with paragraph (a)(3)(i) or (ii) of this section, the reporting requirements in § 60.5420a(b)(7)(i)(C), and the recordkeeping requirements in § 60.5420a(c)(15)(iii).

(i) If the total production for the well site is at or below 15 boe per day for the first 30 days after the action is completed, according to § 60.5415a(j), you must either continue to comply with paragraph (a)(2) of this section or comply with paragraph (a)(1) of this section.

(ii) If the total production for the well site is greater than 15 boe per day for the first 30 days after the action is completed, according to § 60.5415a(j), you must comply with paragraph (a)(1) of this section and conduct an initial monitoring survey for the collection of fugitive emissions components at the well site in accordance with the same schedule as for modified well sites as specified in § 60.5397a(f)(1).

* * * * *

(c) * * *

(2) Technique for determining fugitive emissions (*i.e.,* Method 21 of appendix A–7 to this part or optical gas imaging meeting the requirements in paragraphs (c)(7)(i) through (vii) of this section).

* * * * *

(7) * * *

(i) Verification that your optical gas imaging equipment meets the specifications of paragraphs (c)(7)(i)(A) and (B) of this section. This verification is an initial verification, and may either be performed by the facility, by the manufacturer, or by a third party. For the purposes of complying with the fugitive emissions monitoring program with optical gas imaging, a fugitive emission is defined as any visible emissions observed using optical gas imaging.

* * * * *

(8) If you are using Method 21 of appendix A–7 of this part, your plan must also include the elements specified in paragraphs (c)(8)(i) through (iii) of this section. For the purposes of complying with the fugitive emissions monitoring program using Method 21 of appendix A–7 of this part a fugitive emission is defined as an instrument reading of 500 ppm or greater.

* * * * *

(iii) Procedures for calibration. The instrument must be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A–7 of this part. At a minimum, you must also conduct precision tests at the interval specified in Method 21 of appendix A–7 of this part, Section 8.1.2, and a calibration drift assessment at the end of each monitoring day. The calibration drift assessment must be conducted as specified in paragraph (c)(8)(iii)(A) of this section. Corrective action for drift assessments is specified in paragraphs (c)(8)(iii)(B) and (C) of this section.

(A) Check the instrument using the same calibration gas that was used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A–7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. If multiple scales are used, record the instrument reading for each scale used. Divide the arithmetic difference of the initial and post-test calibration response by the corresponding calibration gas value for each scale and multiply by 100 to express the calibration drift as a percentage.

(B) If a calibration drift assessment shows a negative drift of more than 10 percent, then all equipment with instrument readings between the fugitive emission definition multiplied by (100 minus the percent of negative drift/divided by 100) and the fugitive emission definition that was monitored since the last calibration must be re-monitored.

(C) If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment with instrument readings above the fugitive emission definition and below the fugitive emission definition multiplied by (100 plus the percent of positive drift/divided by 100) monitored since the last calibration may be re-monitored.

(d) Each fugitive emissions monitoring plan must include the elements specified in paragraphs (d)(1) through (3) of this section, at a minimum, as applicable.

(1) If you are using optical gas imaging, your plan must include procedures to ensure that all fugitive emissions components are monitored during each survey. Example procedures include, but are not limited to, a sitemap with an observation path, a written narrative of where the fugitive emissions components are located and how they will be monitored, or an inventory of fugitive emissions components.

(2) If you are using Method 21 of appendix A–7 of this part, your plan must include a list of fugitive emissions components to be monitored and method for determining the location of fugitive emissions components to be monitored in the field (*e.g.,* tagging, identification on a process and instrumentation diagram, etc.).

(3) Your fugitive emissions monitoring plan must include the written plan developed for all of the fugitive emissions components designated as difficult-to-monitor in accordance with paragraph (g)(3) of this section, and the written plan for fugitive emissions components designated as unsafe-to-monitor in accordance with paragraph (g)(4) of this section.

* * * * *

(f)(1) You must conduct an initial monitoring survey within 90 days of the startup of production, as defined in

§ 60.5430a, for each collection of fugitive emissions components at a new well site or by June 3, 2017, whichever is later. For a modified collection of fugitive emissions components at a well site, the initial monitoring survey must be conducted within 90 days of the startup of production for each collection of fugitive emissions components after the modification or by June 3, 2017, whichever is later. Notwithstanding the preceding deadlines, for each collection of fugitive emissions components at a well site located on the Alaskan North Slope, as defined in § 60.5430a, that starts up production between September and March, you must conduct an initial monitoring survey within 6 months of the startup of production for a new well site, within 6 months of the first day of production after a modification of the collection of fugitive emission components, or by the following June 30, whichever is latest.

(2) You must conduct an initial monitoring survey within 90 days of the startup of a new compressor station for each collection of fugitive emissions components at the new compressor station or by June 3, 2017, whichever is later. For a modified collection of fugitive emissions components at a compressor station, the initial monitoring survey must be conducted within 90 days of the modification or by June 3, 2017, whichever is later. Notwithstanding the preceding deadlines, for each collection of fugitive emissions components at a new compressor station located on the Alaskan North Slope that starts up between September and March, you must conduct an initial monitoring survey within 6 months of the startup date for new compressor stations, within 6 months of the modification, or by the following June 30, whichever is latest.

(g) A monitoring survey of each collection of fugitive emissions components at a well site or at a compressor station must be performed at the frequencies specified in paragraphs (g)(1) and (2) of this section, with the exceptions noted in paragraphs (g)(3) through (5) of this section.

(1) Except as provided in this paragraph (g)(1), a monitoring survey of each collection of fugitive emissions components at a well site must be conducted at least semiannually after the initial survey. Consecutive semiannual monitoring surveys must be conducted at least 4 months apart and no more than 7 months apart. A monitoring survey of each collection of fugitive emissions components at a well site located on the Alaskan North Slope must be conducted at least annually. Consecutive annual monitoring surveys must be conducted at least 9 months apart and no more than 13 months apart.

(2) Except as provided in this paragraph (g)(2), a monitoring survey of the collection of fugitive emissions components at a compressor station must be conducted at least semiannually after the initial survey. Consecutive semiannual monitoring surveys must be conducted at least 4 months apart and no more than 7 months apart. A monitoring survey of the collection of fugitive emissions components at a compressor station located on the Alaskan North Slope must be conducted at least annually. Consecutive annual monitoring surveys must be conducted at least 9 months apart and no more than 13 months apart.

* * * * *

(5) You are no longer required to comply with the requirements of paragraph (g)(1) of this section when the owner or operator removes all major production and processing equipment, as defined in § 60.5430a, such that the well site becomes a wellhead only well site. If any major production and processing equipment is subsequently added to the well site, then the owner or operator must comply with the requirements in paragraphs (f)(1) and (g)(1) of this section.

(h) Each identified source of fugitive emissions shall be repaired, as defined in § 60.5430a, in accordance with paragraphs (h)(1) and (2) of this section.

(1) A first attempt at repair shall be made no later than 30 calendar days after detection of the fugitive emissions.

(2) Repair shall be completed as soon as practicable, but no later than 30 calendar days after the first attempt at repair as required in paragraph (h)(1) of this section.

(3) If the repair is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair must be completed during the next scheduled compressor station shutdown for maintenance, scheduled well shutdown, scheduled well shut-in, after a scheduled vent blowdown, or within 2 years, whichever is earliest. For purposes of this paragraph (h)(3), a vent blowdown is the opening of one or more blowdown valves to depressurize major production and processing equipment, other than a storage vessel.

(4) Each identified source of fugitive emissions must be resurveyed to complete repair according to the requirements in paragraphs (h)(4)(i) through (iv) of this section, to ensure that there are no fugitive emissions.

(i) The operator may resurvey the fugitive emissions components to verify repair using either Method 21 of appendix A–7 of this part or optical gas imaging.

(ii) For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph must be taken of that component or the component must be tagged during the monitoring survey when the fugitives were initially found for identification purposes and subsequent repair. The digital photograph must include the date that the photograph was taken and must clearly identify the component by location within the site (*e.g.,* the latitude and longitude of the component or by other descriptive landmarks visible in the picture).

(iii) Operators that use Method 21 of appendix A–7 of this part to resurvey the repaired fugitive emissions components are subject to the resurvey provisions specified in paragraphs (h)(4)(iii)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the Method 21 instrument indicates a concentration of less than 500 ppm above background or when no soap bubbles are observed when the alternative screening procedures specified in section 8.3.3 of Method 21 of appendix A–7 of this part are used.

(B) Operators must use the Method 21 monitoring requirements specified in paragraph (c)(8)(ii) of this section or the alternative screening procedures specified in section 8.3.3 of Method 21 of appendix A–7 of this part.

(iv) Operators that use optical gas imaging to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (h)(4)(iv)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the optical gas imaging instrument shows no indication of visible emissions.

(B) Operators must use the optical gas imaging monitoring requirements specified in paragraph (c)(7) of this section.

* * * * *

■ 9. Section 60.5398a is revised to read as follows:

§ 60.5398a What are the alternative means of emission limitations for VOC from well completions, reciprocating compressors, the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under § 60.5375a, § 60.5385a, or § 60.5397a, the Administrator will publish, in the **Federal Register**, a notice permitting the use of that alternative means for the purpose of compliance with § 60.5375a, § 60.5385a, or § 60.5397a. The authority to approve an alternative means of emission limitation is retained by the Administrator and shall not be delegated to States under section 111(c) of the Clean Air Act (CAA).

(b) Any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.

(c) Determination of equivalence to the design, equipment, work practice, or operational requirements of this section will be evaluated by the following guidelines:

(1) The applicant must provide information that is sufficient for demonstrating the alternative means of emission limitation achieves emission reductions that are at least equivalent to the emission reductions that would be achieved by complying with the relevant standards. At a minimum, the application must include the following information:

(i) Details of the specific equipment or components that would be included in the alternative.

(ii) A description of the alternative work practice, including, as appropriate, the monitoring method, monitoring instrument or measurement technology, and the data quality indicators for precision and bias.

(iii) The method detection limit of the technology, technique, or process and a description of the procedures used to determine the method detection limit. At a minimum, the applicant must collect, verify, and submit field data encompassing seasonal variations to support the determination of the method detection limit. The field data may be supplemented with modeling analyses, controlled test site data, or other documentation.

(iv) Any initial and ongoing quality assurance/quality control measures necessary for maintaining the technology, technique, or process, and the timeframes for conducting such measures.

(v) Frequency of measurements. For continuous monitoring techniques, the minimum data availability.

(vi) Any restrictions for using the technology, technique, or process.

(vii) Initial and continuous compliance procedures, including recordkeeping and reporting, if the compliance procedures are different than those specified in this subpart.

(2) For each technology, technique, or process for which a determination of equivalency is requested, the application must provide a demonstration that the emission reduction achieved by the alternative means of emission limitation is at least equivalent to the emission reduction that would be achieved by complying with the relevant standards in this subpart.

(d) Any alternative means of emission limitations approved under this section shall constitute a required work practice, equipment, design, or operational standard within the meaning of section 111(h)(1) of the CAA.

■ 10. Add § 60.5399a to read as follows:

§ 60.5399a What alternative fugitive emissions standards apply to the affected facility which is the collection of fugitive emissions components at a well site and the affected facility which is the collection of fugitive emissions components at a compressor station: Equivalency with state, local, and tribal programs?

This section provides alternative fugitive emissions standards based on programs under state, local, or tribal authorities for the collection of fugitive emissions components, as defined in § 60.5430a, located at well sites and compressor stations. Paragraphs (a) through (e) of this section outline the procedure for submittal and approval of alternative fugitive emissions standards. Paragraphs (f) through (n) provide approved alternative fugitive emissions standards. The terms ''fugitive emissions components'' and ''repaired'' are defined in § 60.5430a and must be applied to the alternative fugitive emissions standards in this section. The requirements for a monitoring plan as specified in § 60.5397a(c) and (d) apply to the alternative fugitive emissions standards in this section.

(a) *Alternative fugitive emissions standards.* If, in the Administrator's judgment, an alternative fugitive emissions standard will achieve a reduction in VOC emissions at least equivalent to the reductions achieved under § 60.5397a, the Administrator will publish, in the **Federal Register**, a notice permitting use of the alternative fugitive emissions standard for the purpose of compliance with § 60.5397a. The authority to approve alternative fugitive emissions standards is retained by the Administrator and shall not be delegated to States under section 111(c) of the CAA.

(b) *Notice.* Any notice under paragraph (a) of this section will be published only after notice and an opportunity for public hearing.

(c) *Evaluation guidelines.* Determination of alternative fugitive emissions standards to the design, equipment, work practice, or operational requirements of § 60.5397a will be evaluated by the following guidelines:

(1) The monitoring instrument, including the monitoring procedure;

(2) The monitoring frequency;

(3) The fugitive emissions definition;

(4) The repair requirements; and

(5) The recordkeeping and reporting requirements.

(d) *Approval of alternative fugitive emissions standard.* Any alternative fugitive emissions standard approved under this section shall:

(1) Constitute a required design, equipment, work practice, or operational standard within the meaning of section 111(h)(1) of the CAA; and

(2) Be made available for use by any owner or operator in meeting the relevant standards and requirements established for affected facilities under § 60.5397a.

(e) *Notification.* (1) An owner or operator must notify the Administrator of adoption of the alternative fugitive emissions standards within the first annual report following implementation of the alternative fugitive emissions standard, as specified in § 60.5420a(a)(3).

(2) An owner or operator implementing one of the alternative fugitive emissions standards must submit the reports specified in § 60.5420a(b)(7)(iii). An owner or operator must also maintain the records specified by the specific alternative fugitive emissions standard for a period of at least 5 years.

(f) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site or a compressor station in the State of California.* An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a well site or a compressor station in the State of California may elect to reduce VOC emissions through compliance with the monitoring, repair, and recordkeeping requirements in the California Code of Regulations, title 17, sections 95665–95667, effective January 1, 2020, as an alternative to complying with the requirements in § 60.5397a(f)(1) and (2), (g)(1) through (4), (h), and (i). The information specified in § 60.5420a(b)(7)(iii)(A) and the information specified in either § 60.5420a(b)(7)(iii)(B) or (C) may be provided as an alternative to the requirements in § 60.5397a(j).

(g) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site or a compressor station in the State of Colorado.* An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a well site or a compressor station in the State of Colorado may elect to comply with the monitoring, repair, and recordkeeping requirements in Colorado Regulation 7, Part D, section I.L or II.E, effective February 14, 2020, for well sites and compressor stations, as an alternative to complying with the requirements in § 60.5397a(f)(1) and (2), (g)(1) through (4), (h), and (i), provided the monitoring instrument used is an optical gas imaging or a Method 21 instrument (see appendix A–7 of this part). Monitoring must be conducted on at least a semiannual basis for well sites and compressor stations. If using the alternative in this paragraph (g), the information specified in § 60.5420a(b)(7)(iii)(A) and (C) must be provided in lieu of the requirements in § 60.5397a(j).

(h) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site in the State of Ohio.* An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a well site in the State of Ohio may elect to comply with the monitoring, repair, and recordkeeping requirements in Ohio General Permits 12.1, Section C.5 and 12.2, Section C.5, effective April 14, 2014, as an alternative to complying with the requirements in § 60.5397a(f)(1), (g)(1), (3), and (4), (h), and (i), provided the monitoring instrument used is optical gas imaging or a Method 21 instrument (see appendix A–7 of this part) with a leak definition and reading of 500 ppm or greater. Monitoring must be conducted on at least a semiannual basis and skip periods cannot be applied. The information specified in § 60.5420a(b)(7)(iii)(A) and the information specified in either § 60.5420a(b)(7)(iii)(B) or (C) may be provided as an alternative to the requirements in § 60.5397a(j).

(i) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a compressor station in the State of Ohio.* An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a compressor station in the State of Ohio may elect to comply with the monitoring, repair, and recordkeeping requirements in Ohio General Permit 18.1, effective February 7, 2017, as an alternative to complying with the requirements in § 60.5397a(f)(2), (g)(2) through (4), (h), and (i), provided the monitoring instrument used is optical gas imaging or a Method 21 instrument (see appendix A–7 of this part) with a leak definition and reading of 500 ppm or greater. Monitoring must be conducted on at least a semiannual basis and skip periods cannot be applied. The information specified in § 60.5420a(b)(7)(iii)(A) and the information specified in either § 60.5420a(b)(7)(iii)(B) or (C) may be provided as an alternative to the requirements in § 60.5397a(j).

(j) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site in the State of Pennsylvania.* An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a well site in the State of Pennsylvania may elect to comply with the monitoring, repair, and recordkeeping requirements in Pennsylvania General Permit 5A, section G, effective August 8, 2018, as an alternative to complying with the requirements in § 60.5397a(f)(2), (g)(2) through (4), (h), and (i), provided the monitoring instrument used is an optical gas imaging or a Method 21 instrument (see appendix A–7 of this part). The information specified in § 60.5420a(b)(7)(iii)(A) and the information specified in either § 60.5420a(b)(7)(iii)(B) or (C) may be provided as an alternative to the requirements in § 60.5397a(j).

(k) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a compressor station in the State of Pennsylvania.* An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a compressor station in the State of Pennsylvania may elect to comply with the monitoring, repair, and recordkeeping requirements in Pennsylvania General Permit 5, section G, effective August 8, 2018, as an alternative to complying with the requirements in § 60.5397a(f)(2), (g)(2) through (4), (h), and (i), provided the monitoring instrument used is an optical gas imaging or a Method 21 instrument (see appendix A–7 of this part). The information specified in § 60.5420a(b)(7)(iii)(A) and the information specified in either § 60.5420a(b)(7)(iii)(B) or (C) may be provided as an alternative to the requirements in § 60.5397a(j).

(l) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site in the State of Texas.* An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a well site in the State of Texas may elect to comply with the monitoring, repair, and recordkeeping requirements in the Air Quality Standard Permit for Oil and Gas Handling and Production Facilities, section (e)(6), effective November 8, 2012, or at 30 Texas Administrative Code section 116.620, effective September 4, 2000, as an alternative to complying with the requirements in § 60.5397a(f)(2), (g)(2) through (4), (h), and (i), provided the monitoring instrument used is optical gas imaging or a Method 21 instrument (see appendix A–7 of this part) with a leak definition and reading of 500 ppm or greater. Monitoring must be conducted on at least a semiannual basis and skip periods may not be applied. If using the requirement in this paragraph (l), the information specified in § 60.5420a(b)(7)(iii)(A) and (C) must be provided in lieu of the requirements in § 60.5397a(j).

(m) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a compressor station in the State of Texas.* An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a compressor in the State of Texas may elect to comply with the monitoring, repair, and recordkeeping requirements in the Air Quality Standard Permit for Oil and Gas Handling and Production Facilities, section (e)(6), effective November 8, 2012, or at 30 Texas Administrative Code section 116.620, effective September 4, 2000, as an alternative to complying with the requirements in § 60.5397a(f)(2), (g)(2) through (4), (h), and (i), provided the monitoring instrument used is optical gas imaging or a Method 21 instrument (see appendix A–7 of this part) with a leak definition and reading of 500 ppm or greater. Monitoring must be conducted on at least a semiannual basis and skip periods may not be applied. If using the alternative in this paragraph (m), the information specified in § 60.5420a(b)(7)(iii)(A) and (C) must be provided in lieu of the requirements in § 60.5397a(j).

(n) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site in the State of Utah.* An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, and is required to control emissions in accordance with Utah Administrative Code R307–506 and R307–507, located at a well site in the State of Utah may elect to comply with the monitoring, repair, and recordkeeping requirements in the Utah Administrative Code R307–509, effective March 2, 2018, as an alternative to complying with the requirements in § 60.5397a(f)(2), (g)(2) through (4), (h), and (i). If using the alternative in this paragraph (n), the information specified in § 60.5420a(b)(7)(iii)(A) and (C) must be provided in lieu of the requirements in § 60.5397a(j).

■ 11. Section 60.5400a is amended by revising the introductory text and paragraph (a) to read as follows:

§ 60.5400a What equipment leak VOC standards apply to affected facilities at an onshore natural gas processing plant?

This section applies to the group of all equipment, except compressors, within a process unit located at an onshore natural gas processing plant.

(a) You must comply with the requirements of §§ 60.482–1a(a), (b), (d), and (e), 60.482–2a, and 60.482–4a through 60.482–11a, except as provided in § 60.5401a, as soon as practicable but no later than 180 days after the initial startup of the process unit.

* * * * *

■ 12. Section 60.5401a is amended by revising paragraphs (e) and (g) to read as follows:

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

* * * * *

(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 monitoring requirements of §§ 60.482–2a(a)(1), 60.482–7a(a), and 60.482–11a(a) and paragraph (b)(1) of this section.

* * * * *

(g) An owner or operator may use the following provisions instead of § 60.485a(b)(2): A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A–7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in § 60.486a(e)(8). For each scale, divide the arithmetic difference of the most recent calibration and the post-test calibration response by the corresponding calibration gas value, and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the most recent calibration response, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the most recent calibration response, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

■ 13. Section 60.5405a is amended by revising the section heading to read as follows:

§ 60.5405a What standards apply to sweetening unit affected facilities?

* * * * *

■ 14. Section 60.5406a is amended by revising the section heading to read as follows:

§ 60.5406a What test methods and procedures must I use for my sweetening unit affected facilities?

* * * * *

■ 15. Section 60.5407a is amended by revising the section heading and paragraph (a) introductory text to read as follows:

§ 60.5407a What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities?

(a) If your sweetening unit affected facility is subject to the provisions of § 60.5405a(a) or (b) you must install, calibrate, maintain, and operate monitoring devices or perform measurements to determine the following operations information on a daily basis:

* * * * *

■ 16. Section 60.5410a is amended by:

■ a. Revising the section heading, introductory text, and paragraphs (c)(1) and (e)(2) through (5);

■ b. Removing paragraph (e)(8);

■ c. Revising paragraphs (g) introductory text, (g)(3), (h), (j) introductory text, and (j)(1); and

■ d. Adding paragraph (k).

The revisions and addition read as follows:

§ 60.5410a How do I demonstrate initial compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, collection of fugitive emissions components at a compressor station, and equipment leaks at onshore natural gas processing plants and sweetening unit affected facilities?

You must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (k) of this section. Except as otherwise provided in this section, the initial compliance period begins on August 2, 2016, or upon initial startup, whichever is later, and ends no later than 1 year after the initial startup date for your affected facility or no later than 1 year after August 2, 2016. The initial compliance period may be less than 1 full year.

* * * * *

(c) * * *

(1) If complying with § 60.5385a(a)(1) or (2), during the initial compliance period, you must continuously monitor the number of hours of operation or track the number of months since initial startup, since August 2, 2016, or since the last rod packing replacement, whichever is latest.

* * * * *

(e) * * *

(2) If you own or operate a pneumatic pump affected facility located at a well site, you must reduce emissions in accordance with § 60.5393a(b)(1) or (2), and you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of § 60.5411a(d) and (e).

(3) If you own or operate a pneumatic pump affected facility located at a well site and there is no control device or process available on site, you must submit the certification in § 60.5420a(b)(8)(i)(A).

(4) If you own or operate a pneumatic pump affected facility located at a well

site, and you are unable to route to an existing control device or to a process due to technical infeasibility, you must submit the certification in § 60.5420a(b)(8)(i)(B).

(5) If you own or operate a pneumatic pump affected facility located at a well site and you reduce emissions in accordance with § 60.5393a(b)(4), you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of § 60.5411a(d) and (e).

* * * * *

(g) For sweetening unit affected facilities, initial compliance is demonstrated according to paragraphs (g)(1) through (3) of this section.

* * * * *

(3) You must submit the results of paragraphs (g)(1) and (2) of this section in the initial annual report submitted for your sweetening unit affected facilities.

(h) For each storage vessel affected facility you must comply with paragraphs (h)(1) through (6) of this section. Except as otherwise provided in this paragraph (h), you must demonstrate initial compliance by August 2, 2016, or within 60 days after startup, whichever is later.

(1) You must determine the potential VOC emission rate as specified in § 60.5365a(e).

(2) You must reduce VOC emissions in accordance with § 60.5395a(a).

(3) If you use a control device to reduce emissions, you must equip the storage vessel with a cover that meets the requirements of § 60.5411a(b) and is connected through a closed vent system that meets the requirements of § 60.5411a(c) and (d) to a control device that meets the conditions specified in § 60.5412a(d) within 60 days after startup for storage vessels constructed, modified, or reconstructed at well sites with no other wells in production, or upon startup for storage vessels constructed, modified, or reconstructed at well sites with one or more wells already in production.

(4) You must conduct an initial performance test as required in § 60.5413a within 180 days after initial startup or within 180 days of August 2, 2016, whichever is later, and you must comply with the continuous compliance requirements in § 60.5415a(e).

(5) You must submit the information required for your storage vessel affected facility in your initial annual report as specified in § 60.5420a(b)(1) and (6).

(6) You must maintain the records required for your storage vessel affected facility, as specified in § 60.5420a(c)(5) through (8), (12) through (14), and (17), as applicable, for each storage vessel affected facility.

* * * * *

(j) To achieve initial compliance with the fugitive emission standards for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station you must comply with paragraphs (j)(1) through (5) of this section.

(1) You must develop a fugitive emissions monitoring plan as required in § 60.5397a(b), (c), and (d).

* * * * *

(k) To demonstrate initial compliance with the requirement to maintain the total well site production at or below 15 boe per day based on a rolling 12-month average, as specified in § 60.5397a(a)(2), you must comply with paragraphs (k)(1) through (3) of this section.

(1) You must demonstrate that the total daily combined oil and natural gas production for all wells at the well site is at or below 15 boe per day, based on a 12-month average from the previous 12 months of operation, according to paragraphs (k)(1)(i) through (iii) of this section within 45 days of the end of each month. The rolling 12-month average of the total well site production determined according to paragraph (k)(1)(iii) of this section must be at or below 15 boe per day.

(i) Determine the daily combined oil and natural gas production for each individual well at the well site for the month. To convert gas production to equivalent barrels of oil, divide the cubic feet of gas produced by 6,000.

(ii) Sum the daily production for each individual well at the well site to determine the total well site production and divide by the number of days in the month. This is the average daily total well site production for the month.

(iii) Use the result determined in paragraph (k)(1)(ii) of this section and average with the daily total well site production values determined for each of the preceding 11 months to calculate the rolling 12-month average of the total well site production.

(2) You must maintain records as specified in § 60.5420a(c)(15)(ii).

(3) You must submit compliance information in the initial and subsequent annual reports as specified in § 60.5420a(b)(7)(i)(C) and (b)(7)(iv).

■ 17. Section 60.5411a is amended by revising the introductory text and paragraphs (a) introductory text, (a)(1), (c)(1) and (2), (d)(1), and (e) to read as follows:

§ 60.5411a What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing emissions from centrifugal compressor wet seal fluid degassing systems, reciprocating compressors, pneumatic pumps and storage vessels?

You must meet the applicable requirements of this section for each cover and closed vent system used to comply with the emission standards for your centrifugal compressor wet seal degassing systems, reciprocating compressors, pneumatic pumps, and storage vessels.

(a) Closed vent system requirements for reciprocating compressors and centrifugal compressor wet seal degassing systems.

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the reciprocating compressor rod packing emissions collection system to a process. You must design the closed vent system to route all gases, vapors, and fumes emitted from the centrifugal compressor wet seal fluid degassing system to a process or a control device that meets the requirements specified in § 60.5412a(a) through (c).

* * * * *

(c) * * *

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the storage vessel affected facility to a control device that meets the requirements specified in § 60.5412a(c) and (d), or to a process.

(2) You must design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual, and auditory inspections or optical gas imaging inspections as specified in § 60.5416a(c).

* * * * *

(d) * * *

(1) You must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all emissions from the affected facility are routed to the control device and that the control device is of sufficient design and capacity to accommodate all emissions from the affected facility, and have it certified by a qualified professional engineer or an in-house engineer with expertise on the design and operation of the closed vent system in accordance with paragraphs (d)(1)(i) and (ii) of this section.

(i) You must provide the following certification, signed and dated by a qualified professional engineer or an in-house engineer: ''I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted and this report was prepared pursuant to the requirements of subpart OOOOa of 40 CFR part 60. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete.''

(ii) The assessment shall be prepared under the direction or supervision of a qualified professional engineer or an in-house engineer who signs the certification in paragraph (d)(1)(i) of this section.

* * * * *

(e) Closed vent system requirements for pneumatic pump affected facilities using a control device or routing emissions to a process.

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the pneumatic pump to a control device or a process.

(2) You must design and operate a closed vent system with no detectable emissions, as demonstrated by § 60.5416a(b), olfactory, visual, and auditory inspections or optical gas imaging inspections as specified in § 60.5416a(d).

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

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

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to § 60.5420a(c)(8).

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

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

■ 18. Section 60.5412a is amended by revising paragraphs (a)(1) introductory text, (a)(1)(iv), (c) introductory text, (d)(1)(iv) introductory text, and (d)(1)(iv)(D) to read as follows:

§ 60.5412a What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my centrifugal compressor, and storage vessel affected facilities?

* * * * *

(a) * * *

(1) Each combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iv) of this section. If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

* * * * *

(iv) You must introduce the vent stream with the primary fuel or use the vent stream as the primary fuel in a boiler or process heater.

* * * * *

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) or (d)(2) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (c)(1) and (2) of this section.

* * * * *

(d) * * *

(1) * * *

(iv) Each enclosed combustion control device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (d)(1)(iv)(A) through (D) of this section. If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

* * * * *

(D) You must introduce the vent stream with the primary fuel or use the vent stream as the primary fuel in a boiler or process heater.

* * * * *

■ 19. Section 60.5413a is amended by revising paragraphs (d)(5)(i) introductory text, (d)(9)(iii), and (d)(12) introductory text to read as follows:

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

* * * * *

(d) * * *

(5) * * *

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

* * * * *

(9) * * *

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

* * * * *

(12) The owner or operator of a combustion control device model tested under this paragraph (d)(12) must submit the information listed in paragraphs (d)(12)(i) through (vi) of this section for each test run in the test report required by this section in accordance with § 60.5420a(b)(10). Owners or operators who claim that any of the performance test information being submitted is confidential business information (CBI) must submit a complete file including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to Attn: CBI Document Control Officer; Office of Air Quality Planning and Standards (OAQPS), Room 521; 109 T.W. Alexander Drive; Research Triangle Park, NC 27711. The same file with the CBI omitted must be submitted to *Oil_and_Gas_PT@EPA.GOV.*

* * * * *

■ 20. Section 60.5415a is amended by:

■ a. Revising the section heading and paragraphs (b) introductory text and (b)(3);

■ b. Removing paragraph (b)(4);

■ c. Revising paragraphs (c)(1), (g) introductory text, (h) introductory text, and (h)(2); and

■ d. Adding paragraphs (i) and (j).

The revisions and additions read as follows:

§ 60.5415a How do I demonstrate continuous compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, and collection of fugitive emissions components at a compressor station affected facilities, equipment leaks at onshore natural gas processing plants and sweetening unit affected facilities?

* * * * *

(b) For each centrifugal compressor affected facility and each pneumatic pump affected facility, you must demonstrate continuous compliance according to paragraph (b)(3) of this section. For each centrifugal compressor affected facility, you also must demonstrate continuous compliance according to paragraphs (b)(1) and (2) of this section.

* * * * *

(3) You must submit the annual reports required by § 60.5420a(b)(1), (3), and (8) and maintain the records as specified in § 60.5420a(c)(2), (6) through (11), (16), and (17), as applicable.

* * * * *

(c) * * *

(1) You must continuously monitor the number of hours of operation for each reciprocating compressor affected facility or track the number of months since initial startup, since August 2, 2016, or since the date of the most recent reciprocating compressor rod packing replacement, whichever is latest.

* * * * *

(g) For each sweetening unit affected facility, you must demonstrate continuous compliance with the standards for SO_2 specified in § 60.5405a(b) according to paragraphs (g)(1) and (2) of this section.

* * * * *

(h) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, you must demonstrate continuous compliance with the fugitive emission standards specified in § 60.5397a(a)(1) according to paragraphs (h)(1) through (4) of this section.

* * * * *

(2) You must repair each identified source of fugitive emissions as required in § 60.5397a(h).

* * * * *

(i) For each collection of fugitive emissions components at a well site complying with § 60.5397a(a)(2), you must demonstrate continuous compliance according to paragraphs (i)(1) through (4) of this section. You must perform the calculations shown in paragraphs (i)(1) through (4) of this section within 45 days of the end of each month. The rolling 12-month average of the total well site production determined according to paragraph (i)(4) of this section must be at or below 15 boe per day.

(1) Begin with the most recent 12-month average.

(2) Determine the daily combined oil and natural gas production of each individual well at the well site for the month. To convert gas production to equivalent barrels of oil, divide the cubic feet of gas produced by 6,000.

(3) Sum the daily production for each individual well at the well site and divide by the number of days in the month. This is the average daily total well site production for the month.

(4) Use the result determined in paragraph (i)(3) of this section and average with the daily total well site production values determined for each of the preceding 11 months to calculate the rolling 12-month average of the total well site production.

(j) To demonstrate that the well site produced at or below 15 boe per day for the first 30 days after startup of production as specified in § 60.5397a(3), you must calculate the daily production for each individual well at the well site during the first 30 days of production after completing any action listed in § 60.5397a(a)(2)(i) through (v) and sum the individual well production values to obtain the total well site production. The calculation must be performed within 45 days of the end of the first 30 days of production after completing any action listed in § 60.5397a(a)(2)(i) through (v). To convert gas production to equivalent barrels of oil, divide cubic feet of gas produced by 6,000.

■ 21. Section 60.5416a is amended by revising the introductory text and paragraphs (a) introductory text, (a)(4) introductory text, (b) introductory text, (c) introductory text, (c)(1), and (c)(2) introductory text, adding paragraph (c)(2)(iv), and revising paragraph (d) to read as follows:

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

For each closed vent system or cover at your centrifugal compressor, reciprocating compressor, pneumatic pump, and storage vessel affected facilities, you must comply with the applicable requirements of paragraphs (a) through (d) 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.

* * * * *

(4) For each bypass device, except as provided for in § 60.5411a(a)(3)(ii), you must meet the requirements of paragraph (a)(4)(i) or (ii) 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 paragraph (a)(1), (2), or (3) of this section, you must meet the requirements of paragraphs (b)(1) through (13) of this section.

* * * * *

(c) *Cover and closed vent system inspections for storage vessel affected facilities.* If you install a control device or route emissions to a process, you must comply with the inspection and recordkeeping requirements for each closed vent system and cover as specified in paragraphs (c)(1) and (2) of this section. You must also comply with the requirements of paragraphs (c)(3) through (7) of this section.

(1) *Closed vent system inspections.* For each closed vent system, you must conduct an inspection as specified in paragraphs (c)(1)(i) through (iii) or paragraph (c)(1)(iv) of this section.

(i) You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(ii) Conduct olfactory, visual, and auditory inspections at least once every calendar month for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(iv) Conduct optical gas imaging inspections for any visible emissions at the same frequency as the frequency for the collection of fugitive emissions components located at the same type of site, as specified in § 60.5397a(g)(1).

(2) *Cover inspections.* For each cover, you must conduct inspections as specified in paragraphs (c)(2)(i) through (iii) or paragraph (c)(2)(iv) of this section.

* * * * *

(iv) Conduct optical gas imaging inspections for any visible emissions at the same frequency as the frequency for the collection of fugitive emissions components located at the same type of site, as specified in § 60.5397a(g)(1).

* * * * *

(d) *Closed vent system inspections for pneumatic pump affected facilities.* If you install a control device or route emissions to a process, you must comply with the inspection and recordkeeping requirements for each closed vent system as specified in paragraph (d)(1) of this section. You must also comply with the requirements of paragraphs (c)(3) through (7) of this section.

(1) For each closed vent system, you must conduct an inspection as specified in paragraphs (d)(1)(i) through (iii), paragraph (d)(1)(iv), or paragraph (d)(1)(v) of this section.

(i) You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(ii) Conduct olfactory, visual, and auditory inspections at least once every calendar month for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(iv) Conduct optical gas imaging inspections for any visible emissions at the same frequency as the frequency for the collection of fugitive components located at the same type of site, as specified in § 60.5397a(g)(1).

(v) Conduct inspections as specified in paragraphs (a)(1) and (2) of this section.

(2) [Reserved]

■ 22. Section 60.5417a is amended by revising the introductory text and paragraph (a) to read as follows:

§ 60.5417a What are the continuous control device monitoring requirements for my centrifugal compressor and storage vessel affected facilities?

You must meet the applicable requirements of this section to demonstrate continuous compliance for each control device used to meet emission standards for your storage vessel affected facility or centrifugal compressor affected facility.

(a) For each control device used to comply with the emission reduction standard for centrifugal compressor affected facilities in § 60.5380a(a)(1), you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with § 60.5412a(a)(3), you are exempt from the requirements of paragraphs (e) and (f) of this section. If you install and operate an enclosed combustion device or control device which is not specifically listed in paragraph (d) of this section, you must demonstrate continuous compliance according to paragraphs (h)(1) through (4) of this section.

* * * * *

■ 23. Revise § 60.5420a to read as follows:

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

(a) *Notifications.* You must submit the notifications according to paragraphs (a)(1) and (2) of this section if you own or operate one or more of the affected facilities specified in § 60.5365a that was constructed, modified, or reconstructed during the reporting period.

(1) If you own or operate an affected facility that is the group of all equipment within a process unit at an onshore natural gas processing plant, or a sweetening unit, you must submit the notifications required in §§ 60.7(a)(1), (3), and (4) and 60.15(d). If you own or operate a well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, or collection of fugitive emissions components at a compressor station, you are not required to submit the notifications required in §§ 60.7(a)(1), (3), and (4) and 60.15(d).

(2)(i) If you own or operate a well affected facility, you must submit a notification to the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the United States Well Number; the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. You may submit the notification in writing or in electronic format.

(ii) If you are subject to state regulations that require advance notification of well completions and you have met those notification requirements, then you are considered to have met the advance notification requirements of paragraph (a)(2)(i) of this section.

(3) An owner or operator electing to comply with the provisions of § 60.5399a shall notify the Administrator of the alternative fugitive emissions standard selected within the annual report, as specified in paragraph (b)(7) of this section.

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (8) and (12) of this section and performance test reports as specified in paragraph (b)(9) or (10) of this section, if applicable. You must submit annual reports following the procedure specified in paragraph (b)(11) of this section. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to § 60.5410a. Subsequent annual reports are due no later than same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (8) and (12) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period.

(1) The general information specified in paragraphs (b)(1)(i) through (iv) of this section is required for all reports.

(i) The company name, facility site name associated with the affected facility, U.S. Well ID or U.S. Well ID associated with the affected facility, if applicable, and address of the affected facility. If an address is not available for the site, include a description of the site location and provide the latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) An identification of each affected facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

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

(2) For each well affected facility that is subject to § 60.5375a(a) or (f), the records of each well completion operation conducted during the reporting period, including the information specified in paragraphs (b)(2)(i) through (xiv) of this section, if applicable. In lieu of submitting the records specified in paragraphs (b)(2)(i) through (xiv) of this section, the owner or operator may submit a list of each well completion with hydraulic fracturing completed during the reporting period, and the digital photograph required by paragraph (c)(1)(v) of this section for each well completion. For each well affected facility that routes flowback entirely through one or more production separators, only the records specified in paragraphs (b)(2)(i) through (iv) and (vi) of this section are required to be reported. For periods where salable gas is unable to be separated, the records specified in paragraphs (b)(2)(iv) and (viii) through (xii) of this section must also be reported, as applicable. For each well affected facility that is subject to § 60.5375a(g), the record specified in paragraph (b)(2)(xv) of this section is required to be reported.

(i) Well Completion ID.

(ii) Latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983.

(iii) U.S. Well ID.

(iv) The date and time of the onset of flowback following hydraulic fracturing or refracturing or identification that the well immediately starts production.

(v) The date and time of each attempt to direct flowback to a separator as required in § 60.5375a(a)(1)(ii).

(vi) The date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production.

(vii) The duration (in hours) of flowback.

(viii) The duration (in hours) of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve).

(ix) The duration (in hours) of combustion.

(x) The duration (in hours) of venting.

(xi) The specific reasons for venting in lieu of capture or combustion.

(xii) For any deviations recorded as specified in paragraph (c)(1)(ii) of this section, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(xiii) For each well affected facility subject to § 60.5375a(f), a record of the well type (*i.e.,* wildcat well, delineation well, or low pressure well (as defined § 60.5430a)) and supporting inputs and calculations, if applicable.

(xiv) For each well affected facility for which you claim an exception under § 60.5375a(a)(3), the specific exception claimed and reasons why the well meets the claimed exception.

(xv) For each well affected facility with less than 300 scf of gas per stock tank barrel of oil produced, the supporting analysis that was performed in order the make that claim, including but not limited to, GOR values for established leases and data from wells in the same basin and field.

(3) For each centrifugal compressor affected facility, the information specified in paragraphs (b)(3)(i) through (v) of this section.

(i) An identification of each centrifugal compressor using a wet seal system constructed, modified, or reconstructed during the reporting period.

(ii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(2) of this section, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(iii) If required to comply with § 60.5380a(a)(2), the information in paragraphs (b)(3)(iii)(A) through (C) of this section.

(A) Dates of each inspection required under § 60.5416a(a) and (b);

(B) Each defect or leak identified during each inspection, date of repair or the date of anticipated repair if the repair is delayed; and

(C) Date and time of each bypass alarm or each instance the key is checked out if you are subject to the bypass requirements of § 60.5416a(a)(4).

(iv) If complying with § 60.5380a(a)(1) with a control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and (e), the information in paragraphs (b)(3)(iv)(A) through (D) of this section.

(A) Identification of the compressor with the control device.

(B) Make, model, and date of purchase of the control device.

(C) For each instance where the inlet gas flow rate exceeds the manufacturer's listed maximum gas flow rate, where there is no indication of the presence of a pilot flame, or where visible emissions exceeded 1 minute in any 15-minute period, include the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(D) For each visible emissions test following return to operation from a maintenance or repair activity, the date of the visible emissions test, the length of the test, and the amount of time for which visible emissions were present.

(v) If complying with § 60.5380a(a)(1) with a control device not tested under § 60.5413a(d), identification of the compressor with the tested control device, the date the performance test was conducted, and pollutant(s) tested. Submit the performance test report following the procedures specified in paragraph (b)(9) of this section.

(4) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(4)(i) through (iii) of this section.

(i) The cumulative number of hours of operation or the number of months since initial startup, since August 2, 2016, or since the previous reciprocating compressor rod packing replacement, whichever is latest. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

(ii) If applicable, for each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(3)(iii) of this section, the date and time the deviation began, duration of the deviation and a description of the deviation.

(iii) If required to comply with § 60.5385a(a)(3), the information in paragraphs (b)(4)(iii)(A) through (C) of this section.

(A) Dates of each inspection required under § 60.5416a(a) and (b);

(B) Each defect or leak identified during each inspection, and date of repair or date of anticipated repair if repair is delayed; and

(C) Date and time of each bypass alarm or each instance the key is checked out if you are subject to the bypass requirements of § 60.5416a(a)(4).

(5) For each pneumatic controller affected facility, the information specified in paragraphs (b)(5)(i) through (iii) of this section.

(i) An identification of each pneumatic controller constructed, modified, or reconstructed during the reporting period, including the month and year of installation, reconstruction or modification and identification information that allows traceability to the records required in paragraph (c)(4)(iii) or (iv) of this section.

(ii) If applicable, reason why the use of pneumatic controller affected facilities with a natural gas bleed rate greater than the applicable standard are required.

(iii) For each instance where the pneumatic controller was not operated in compliance with the requirements specified in § 60.5390a, a description of the deviation, the date and time the deviation began, and the duration of the deviation.

(6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) through (ix) of this section.

(i) An identification, including the location, of each storage vessel affected facility for which construction, modification, or reconstruction commenced during the reporting period. The location of the storage vessel shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) Documentation of the VOC emission rate determination according to § 60.5365a(e)(1) for each storage vessel that became an affected facility during the reporting period or is returned to service during the reporting period.

(iii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(5) of this section, the date and time the deviation began, duration of the deviation and a description of the deviation.

(iv) A statement that you have met the requirements specified in § 60.5410a(h)(2) and (3).

(v) For each storage vessel constructed, modified, reconstructed, or returned to service during the reporting period complying with § 60.5395a(a)(2) with a control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and (e), the information in paragraphs (b)(6)(v)(A) through (D) of this section.

(A) Identification of the storage vessel with the control device.

(B) Make, model, and date of purchase of the control device.

(C) For each instance where the inlet gas flow rate exceeds the manufacturer's listed maximum gas flow rate, where there is no indication of the presence of a pilot flame, or where visible emissions exceeded 1 minute in any 15-minute period, include the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(D) For each visible emissions test following return to operation from a maintenance or repair activity, the date of the visible emissions test, the length of the test, and the amount of time for which visible emissions were present.

(vi) If complying with § 60.5395a(a)(2) with a control device not tested under § 60.5413a(d), identification of the storage vessel with the tested control device, the date the performance test was conducted, and pollutant(s) tested. Submit the performance test report following the procedures specified in paragraph (b)(9) of this section.

(vii) If required to comply with § 60.5395a(b)(1), the information in paragraphs (b)(6)(vii)(A) through (C) of this section.

(A) Dates of each inspection required under § 60.5416a(c);

(B) Each defect or leak identified during each inspection, and date of repair or date of anticipated repair if repair is delayed; and

(C) Date and time of each bypass alarm or each instance the key is checked out if you are subject to the bypass requirements of § 60.5416a(c)(3).

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

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

(7) For the collection of fugitive emissions components at each well site and the collection of fugitive emissions components at each compressor station, report the information specified in paragraphs (b)(7)(i) through (iii) of this section, as applicable.

(i)(A) Designation of the type of site (*i.e.,* well site or compressor station) at which the collection of fugitive emissions components is located.

(B) For each collection of fugitive emissions components at a well site that became an affected facility during the reporting period, you must include the date of the startup of production or the date of the first day of production after modification. For each collection of fugitive emissions components at a compressor station that became an affected facility during the reporting period, you must include the date of startup or the date of modification.

(C) For each collection of fugitive emissions components at a well site that meets the conditions specified in either § 60.5397a(a)(1)(i) or (ii), you must specify the well site is a low production well site and submit the total production for the well site.

(D) For each collection of fugitive emissions components at a well site where during the reporting period you complete the removal of all major production and processing equipment such that the well site contains only one or more wellheads, you must include the date of the change to status as a wellhead only well site.

(E) For each collection of fugitive emissions components at a well site where you previously reported under paragraph (b)(7)(i)(C) of this section the removal of all major production and processing equipment and during the reporting period major production and processing equipment is added back to the well site, the date that the first piece of major production and processing equipment is added back to the well site.

(ii) For each fugitive emissions monitoring survey performed during the annual reporting period, the information specified in paragraphs (b)(7)(ii)(A) through (G) of this section.

(A) Date of the survey.

(B) Monitoring instrument used.

(C) Any deviations from the monitoring plan elements under § 60.5397a(c)(1), (2), and (7) and (c)(8)(i) or a statement that there were no deviations from these elements of the monitoring plan.

(D) Number and type of components for which fugitive emissions were detected.

(E) Number and type of fugitive emissions components that were not repaired as required in § 60.5397a(h).

(F) Number and type of fugitive emission components (including designation as difficult-to-monitor or unsafe-to-monitor, if applicable) on delay of repair and explanation for each delay of repair.

(G) Date of planned shutdown(s) that occurred during the reporting period if there are any components that have been placed on delay of repair.

(iii) For each collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station complying with an alternative fugitive emissions standard under § 60.5399a, in lieu of the information specified in paragraphs (b)(7)(i) and (ii) of this section, you must provide the information specified in paragraphs (b)(7)(iii)(A) through (C) of this section.

(A) The alternative standard with which you are complying.

(B) The site-specific reports specified by the specific alternative fugitive emissions standard, submitted in the format in which they were submitted to the state, local, or tribal authority. If the report is in hard copy, you must scan the document and submit it as an electronic attachment to the annual report required in paragraph (b) of this section.

(C) If the report specified by the specific alternative fugitive emissions standard is not site-specific, you must submit the information specified in paragraphs (b)(7)(i) and (ii) of this section for each individual site complying with the alternative standard.

(8) For each pneumatic pump affected facility, the information specified in paragraphs (b)(8)(i) through (iv) of this section.

(i) For each pneumatic pump that is constructed, modified or reconstructed during the reporting period, you must provide certification that the pneumatic pump meets one of the conditions described in paragraph (b)(8)(i)(A), (B), or (C) of this section.

(A) No control device or process is available on site.

(B) A control device or process is available on site and the owner or operator has determined in accordance with § 60.5393a(b)(5) that it is technically infeasible to capture and route the emissions to the control device or process.

(C) Emissions from the pneumatic pump are routed to a control device or process. If the control device is designed to achieve less than 95 percent emissions reduction, specify the percent emissions reductions the control device is designed to achieve.

(ii) For any pneumatic pump affected facility which has been previously reported as required under paragraph (b)(8)(i) of this section and for which a change in the reported condition has occurred during the reporting period, provide the identification of the pneumatic pump affected facility and the date it was previously reported and a certification that the pneumatic pump meets one of the conditions described in paragraph (b)(8)(ii)(A), (B), (C), or (D) of this section.

(A) A control device has been added to the location and the pneumatic pump now reports according to paragraph (b)(8)(i)(C) of this section.

(B) A control device has been added to the location and the pneumatic pump affected facility now reports according to paragraph (b)(8)(i)(B) of this section.

(C) A control device or process has been removed from the location or otherwise is no longer available and the pneumatic pump affected facility now report according to paragraph (b)(8)(i)(A) of this section.

(D) A control device or process has been removed from the location or is otherwise no longer available and the owner or operator has determined in accordance with § 60.5393a(b)(5) through an engineering evaluation that it is technically infeasible to capture and route the emissions to another control device or process.

(iii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(16)(ii) of this section, the date and time the deviation began, duration of the deviation, and a description of the deviation.

(iv) If required to comply with § 60.5393a(b), the information in paragraphs (b)(8)(iv)(A) through (C) of this section.

(A) Dates of each inspection required under § 60.5416a(d);

(B) Each defect or leak identified during each inspection, and date of repair or date of anticipated repair if repair is delayed; and

(C) Date and time of each bypass alarm or each instance the key is checked out if you are subject to the bypass requirements of § 60.5416a(c)(3).

(9) Within 60 days after the date of completing each performance test (see § 60.8) required by this subpart, except testing conducted by the manufacturer as specified in § 60.5413a(d), you must submit the results of the performance test following the procedure specified in either paragraph (b)(9)(i) or (ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test, you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), except as outlined in this paragraph (b)(9)(i). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as confidential business information (CBI). Anything submitted using CEDRI cannot later be claimed CBI. Performance test data must be submitted in a file format generated through the use of the EPA's ERT or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim, you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph (b)(9)(i). All CBI claims must be asserted at the time of submission. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in § 60.4.

(10) For combustion control devices tested by the manufacturer in accordance with § 60.5413a(d), an electronic copy of the performance test results required by § 60.5413a(d) shall be submitted via email to *Oil_and_Gas_PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following website: *epa.gov/airquality/oilandgas/.*

(11) You must submit reports to the EPA via CEDRI, except as outlined in this paragraph (b)(11). (CEDRI can be accessed through the EPA's CDX (*https://cdx.epa.gov/*).) The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Anything submitted using CEDRI cannot later be claimed CBI. You must use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri/*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in § 60.4. Once the form has been available in CEDRI for at least 90 calendar days, you must begin submitting all subsequent reports via CEDRI. The reports must be submitted by the

deadlines specified in this subpart, regardless of the method in which the reports are submitted. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim, submit a complete report generated using the appropriate form in CEDRI or an alternate electronic file consistent with the XML schema listed on the EPA's CEDRI website, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage medium to the EPA. The electronic medium shall be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Fuels and Incineration Group, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted shall be submitted to the EPA via CEDRI. All CBI claims must be asserted at the time of submission. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(12) You must submit the certification signed by the qualified professional engineer or in-house engineer according to § 60.5411a(d) for each closed vent system routing to a control device or process.

(13) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with the reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (b)(13)(i) through (vii) of this section.

(i) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(ii) The outage must have occurred within the period of time beginning 5 business days prior to the date that the submission is due.

(iii) The outage may be planned or unplanned.

(iv) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or caused a delay in reporting.

(v) You must provide to the Administrator a written description identifying:

(A) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to the EPA system outage;

(C) Measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(vi) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(vii) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(14) If you are required to electronically submit a report through CEDRI in the EPA's CDX, the owner or operator may assert a claim of force majeure for failure to timely comply with the reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (b)(14)(i) through (v) of this section.

(i) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning 5 business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(ii) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or caused a delay in reporting.

(iii) You must provide to the Administrator:

(A) A written description of the force majeure event;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(C) Measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(iv) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(v) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

(c) *Recordkeeping requirements.* You must maintain the records identified as specified in § 60.7(f) and in paragraphs (c)(1) through (18) of this section. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years. Any records required to be maintained by this subpart that are submitted electronically via the EPA's CDX may be maintained in electronic format.

(1) The records for each well affected facility as specified in paragraphs (c)(1)(i) through (vii) of this section, as applicable. For each well affected facility for which you make a claim that the well affected facility is not subject to the requirements for well completions pursuant to § 60.5375a(g), you must maintain the record in paragraph (c)(1)(vi) of this section, only. For each well affected facility that routes flowback entirely through one or more production separators that are designed to accommodate flowback, only records of the United States Well Number, the latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983, the Well Completion ID, and the date and time of startup of production are required. For periods where salable gas is unable to be separated, records of the date and time of onset of flowback, the duration and disposition of recovery, the duration of combustion and venting (if applicable), reasons for venting (if applicable), and deviations are required.

(i) Records identifying each well completion operation for each well affected facility.

(ii) Records of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in § 60.5375a, including the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(iii) You must maintain the records specified in paragraphs (c)(1)(iii)(A) through (C) of this section.

(A) For each well affected facility required to comply with the requirements of § 60.5375a(a), you must record: The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time of each attempt to direct flowback to a separator as required in § 60.5375a(a)(1)(ii); the date and time of each occurrence of returning to the initial flowback stage under § 60.5375a(a)(1)(i); and the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours. In addition, for wells where it is technically infeasible to route the recovered gas as specified in § 60.5375a(a)(1)(ii), you must record the reasons for the claim of technical infeasibility with respect to all four options provided in § 60.5375a(a)(1)(ii).

(B) For each well affected facility required to comply with the requirements of § 60.5375a(f), you must record: Latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours.

(C) For each well affected facility for which you make a claim that it meets the criteria of § 60.5375a(a)(1)(iii)(A), you must maintain the following:

(*1*) The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours.

(*2*) If applicable, records that the conditions of § 60.5375a(a)(1)(iii)(A) are no longer met and that the well completion operation has been stopped and a separator installed. The records shall include the date and time the well completion operation was stopped and the date and time the separator was installed.

(*3*) A record of the claim signed by the certifying official that no liquids collection is at the well site. The claim must include a certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(iv) For each well affected facility for which you claim an exception under § 60.5375a(a)(3), you must record: The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the specific exception claimed; the starting date and ending date for the period the well operated under the exception; and an explanation of why the well meets the claimed exception.

(v) For each well affected facility required to comply with both § 60.5375a(a)(1) and (3), if you are using a digital photograph in lieu of the records required in paragraphs (c)(1)(i) through (iv) of this section, you must retain the records of the digital photograph as specified in § 60.5410a(a)(4).

(vi) For each well affected facility for which you make a claim that the well affected facility is not subject to the well completion standards according to § 60.5375a(g), you must maintain:

(A) A record of the analysis that was performed in order the make that claim, including but not limited to, GOR values for established leases and data from wells in the same basin and field;

(B) the latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number;

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

(vii) For each well affected facility subject to § 60.5375a(f), a record of the well type (*i.e.,* wildcat well, delineation well, or low pressure well (as defined § 60.5430a)) and supporting inputs and calculations, if applicable.

(2) For each centrifugal compressor affected facility, you must maintain records of deviations in cases where the centrifugal compressor was not operated in compliance with the requirements specified in § 60.5380a, including a description of each deviation, the date and time each deviation began and the duration of each deviation. Except as specified in paragraph (c)(2)(viii) of this section, you must maintain the records in paragraphs (c)(2)(i) through (vii) of this section for each control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and (e) and used to comply with § 60.5380a(a)(1) for each centrifugal compressor.

(i) Make, model, and serial number of purchased device.

(ii) Date of purchase.

(iii) Copy of purchase order.

(iv) Location of the centrifugal compressor and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(v) Inlet gas flow rate.

(vi) Records of continuous compliance requirements in § 60.5413a(e) as specified in paragraphs (c)(2)(vi)(A) through (E) of this section.

(A) Records that the pilot flame is present at all times of operation.

(B) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15-minute period.

(C) Records of the maintenance and repair log.

(D) Records of the visible emissions test following return to operation from a maintenance or repair activity, including the date of the visible emissions test, the length of the test, and the amount of time for which visible emissions were present.

(E) Records of the manufacturer's written operating instructions, procedures, and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(vii) Records of deviations for instances where the inlet gas flow rate exceeds the manufacturer's listed maximum gas flow rate, where there is no indication of the presence of a pilot flame, or where visible emissions exceeded 1 minute in any 15-minute period, including a description of the deviation, the date and time the deviation began, and the duration of the deviation.

(viii) As an alternative to the requirements of paragraph (c)(2)(iv) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the centrifugal compressor and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the centrifugal compressor and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(3) For each reciprocating compressor affected facility, you must maintain the records in paragraphs (c)(3)(i) through (iii) of this section.

(i) Records of the cumulative number of hours of operation or number of months since initial startup, since August 2, 2016, or since the previous replacement of the reciprocating compressor rod packing, whichever is latest. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

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

(iii) Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in § 60.5385a, including the date and time the deviation began, duration of the deviation, and a description of the deviation.

(4) For each pneumatic controller affected facility, you must maintain the records identified in paragraphs (c)(4)(i) through (v) of this section, as applicable.

(i) Records of the month and year of installation, reconstruction, or modification, location in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983, identification information that allows traceability to the records required in paragraph (c)(4)(iii) or (iv) of this section and manufacturer specifications for each pneumatic controller constructed, modified, or reconstructed.

(ii) Records of the demonstration that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than the applicable standard are required and the reasons why.

(iii) If the pneumatic controller is not located at a natural gas processing plant, records of the manufacturer's specifications indicating that the controller is designed such that natural gas bleed rate is less than or equal to 6 standard cubic feet per hour.

(iv) If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.

(v) For each instance where the pneumatic controller was not operated in compliance with the requirements specified in § 60.5390a, a description of the deviation, the date and time the deviation began, and the duration of the deviation.

(5) For each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) through (vii) of this section.

(i) If required to reduce emissions by complying with § 60.5395a(a)(2), the records specified in §§ 60.5420a(c)(6) through (8) and 60.5416a(c)(6)(ii) and (c)(7)(ii). You must maintain the records in paragraph (c)(5)(vi) of this section for each control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and (e) and used to comply with § 60.5395a(a)(2) for each storage vessel.

(ii) Records of each VOC emissions determination for each storage vessel affected facility made under § 60.5365a(e) including identification of the model or calculation methodology used to calculate the VOC emission rate.

(iii) For each instance where the storage vessel was not operated in compliance with the requirements specified in §§ 60.5395a, 60.5411a, 60.5412a, and 60.5413a, as applicable, a description of the deviation, the date and time each deviation began, and the duration of the deviation.

(iv) For storage vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), records indicating the number of consecutive days that the vessel is located at a site in the crude oil and natural gas production source category. If a storage vessel is removed from a site and, within 30 days, is either returned to the site or replaced by another storage vessel at the site to serve the same or similar function, then the entire period since the original storage vessel was first located at the site, including the days when the storage vessel was removed, will be added to the count towards the number of consecutive days.

(v) You must maintain records of the identification and location in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983 of each storage vessel affected facility.

(vi) Except as specified in paragraph (c)(5)(vi)(G) of this section, you must maintain the records specified in paragraphs (c)(5)(vi)(A) through (H) of this section for each control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and (e) and used to comply with § 60.5395a(a)(2) for each storage vessel.

(A) Make, model, and serial number of purchased device.

(B) Date of purchase.

(C) Copy of purchase order.

(D) Location of the control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(E) Inlet gas flow rate.

(F) Records of continuous compliance requirements in § 60.5413a(e) as specified in paragraphs (c)(5)(vi)(F)(*1*) through (*5*) of this section.

(*1*) Records that the pilot flame is present at all times of operation.

(*2*) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15-minute period.

(*3*) Records of the maintenance and repair log.

(*4*) Records of the visible emissions test following return to operation from a maintenance or repair activity, including the date of the visible emissions test, the length of the test, and the amount of time for which visible emissions were present.

(*5*) Records of the manufacturer's written operating instructions, procedures, and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(G) Records of deviations for instances where the inlet gas flow rate exceeds the manufacturer's listed maximum gas flow rate, where there is no indication of the presence of a pilot flame, or where visible emissions exceeded 1 minute in any 15-minute period, including a description of the deviation, the date and time the deviation began, and the duration of the deviation.

(H) As an alternative to the requirements of paragraph (c)(5)(vi)(D) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the storage vessel and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the storage vessel and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(vii) Records of the date that each storage vessel affected facility is removed from service and returned to service, as applicable.

(6) Records of each closed vent system inspection required under § 60.5416a(a)(1) and (2) and (b) for centrifugal compressors and reciprocating compressors, § 60.5416a(c)(1) for storage vessels, or § 60.5416a(e) for pneumatic pumps as required in paragraphs (c)(6)(i) through (iii) of this section.

(i) A record of each closed vent system inspection or no detectable emissions monitoring survey. You must include an identification number for each closed vent system (or other unique identification description selected by you) and the date of the inspection.

(ii) For each defect or leak detected during inspections required by § 60.5416a(a)(1) and (2), (b), (c)(1), or (d), you must record the location of the defect or leak, a description of the defect or the maximum concentration reading obtained if using Method 21 of appendix A–7 of this part, the date of detection, and the date the repair to correct the defect or leak is completed.

(iii) If repair of the defect is delayed as described in § 60.5416a(b)(10), you must record the reason for the delay and the date you expect to complete the repair.

(7) A record of each cover inspection required under § 60.5416a(a)(3) for centrifugal or reciprocating compressors or § 60.5416a(c)(2) for storage vessels as required in paragraphs (c)(7)(i) through (iii) of this section.

(i) A record of each cover inspection. You must include an identification number for each cover (or other unique identification description selected by you) and the date of the inspection.

(ii) For each defect detected during inspections required by § 60.5416a(a)(3) or (c)(2), you must record the location of the defect, a description of the defect, the date of detection, the corrective action taken the repair the defect, and the date the repair to correct the defect is completed.

(iii) If repair of the defect is delayed as described in § 60.5416a(b)(10) or (c)(5), you must record the reason for the delay and the date you expect to complete the repair.

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

(9) [Reserved]

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

(11) For each centrifugal compressor affected facility subject to the control device requirements of § 60.5412a(a), (b), and (c), records of minimum and maximum operating parameter values, continuous parameter monitoring system data, calculated averages of continuous parameter monitoring system data, results of all compliance calculations, and results of all inspections.

(12) For each carbon adsorber installed on storage vessel affected facilities, records of the schedule for carbon replacement (as determined by the design analysis requirements of § 60.5412a(d)(2)) and records of each carbon replacement as specified in § 60.5412a(c)(1).

(13) For each storage vessel affected facility subject to the control device requirements of § 60.5412a(c) and (d), you must maintain records of the inspections, including any corrective actions taken, the manufacturers' operating instructions, procedures and maintenance schedule as specified in § 60.5417a(h)(3). You must maintain records of EPA Method 22 of appendix A–7 of this part, section 11 results, which include: Company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22–1 in EPA Method 22 of appendix A–7 of this part. Manufacturer's operating instructions, procedures and maintenance schedule must be available for inspection.

(14) A log of records as specified in § 60.5412a(d)(1)(iii), for all inspection, repair, and maintenance activities for each control device failing the visible emissions test.

(15) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, maintain the records identified in paragraphs (c)(15)(i) through (viii) of this section.

(i) The date of the startup of production or the date of the first day of production after modification for each collection of fugitive emissions components at a well site and the date of startup or the date of modification for each collection of fugitive emissions components at a compressor station.

(ii) For each collection of fugitive emissions components at a well site complying with § 60.5397a(a)(2), you must maintain records of the daily production and calculations demonstrating that the rolling 12-month average is at or below 15 boe per day no later than 12 months before complying with § 60.5397a(a)(2).

(iii) For each collection of fugitive emissions components at a well site complying with § 60.5397a(a)(3)(i), you must keep records of daily production and calculations for the first 30 days after completion of any action listed in § 60.5397a(a)(2)(i) through (v) demonstrating that total production from the well site is at or below 15 boe per day, or maintain records demonstrating the rolling 12-month average total production for the well site is at or below 15 boe per day.

(iv) For each collection of fugitive emissions components at a well site complying with § 60.5397a(a)(3)(ii), you must keep the records specified in paragraphs (c)(15)(i), (vi), and (vii) of this section.

(v) For each collection of fugitive emissions components at a well site where you complete the removal of all major production and processing equipment such that the well site contains only one or more wellheads, record the date the well site completes the removal of all major production and processing equipment from the well site, and, if the well site is still producing, record the well ID or separate tank battery ID receiving the production from the well site. If major production and processing equipment is subsequently added back to the well site, record the date that the first piece of major production and processing equipment is added back to the well site.

(vi) The fugitive emissions monitoring plan as required in § 60.5397a(b), (c), and (d).

(vii) The records of each monitoring survey as specified in paragraphs (c)(15)(vii)(A) through (I) of this section.

(A) Date of the survey.

(B) Beginning and end time of the survey.

(C) Name of operator(s), training, and experience of the operator(s) performing the survey.

(D) Monitoring instrument used.

(E) Fugitive emissions component identification when Method 21 of appendix A–7 of this part is used to perform the monitoring survey.

(F) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey. For compressor stations, operating mode of each compressor (*i.e.,* operating, standby pressurized, and not operating-depressurized modes) at the station at the time of the survey.

(G) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(H) Records of calibrations for the instrument used during the monitoring survey.

(I) Documentation of each fugitive emission detected during the monitoring survey, including the information specified in paragraphs (c)(15)(vii)(I)(*1*) through (*8*) of this section.

(*1*) Location of each fugitive emission identified.

(*2*) Type of fugitive emissions component, including designation as difficult-to-monitor or unsafe-to-monitor, if applicable.

(*3*) If Method 21 of appendix A–7 of this part is used for detection, record the component ID and instrument reading.

(*4*) For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph or video must be taken of that component or the component must be tagged for identification purposes. The digital photograph must include the date that the photograph was taken and must clearly identify the component by location within the site (*e.g.,* the latitude and longitude of the component or by other descriptive landmarks visible in the picture). The digital photograph or identification (*e.g.,* tag) may be removed after the repair is completed, including verification of repair with the resurvey.

(*5*) The date of first attempt at repair of the fugitive emissions component(s).

(*6*) The date of successful repair of the fugitive emissions component, including the resurvey to verify repair and instrument used for the resurvey.

(*7*) Identification of each fugitive emission component placed on delay of repair and explanation for each delay of repair

(*8*) Date of planned shutdowns that occur while there are any components that have been placed on delay of repair.

(viii) For each collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station complying with an alternative means of emissions limitation under § 60.5399a, you must maintain the records specified by the specific alternative fugitive emissions standard for a period of at least 5 years.

(16) For each pneumatic pump affected facility, you must maintain the records identified in paragraphs (c)(16)(i) through (v) of this section.

(i) Records of the date, location, and manufacturer specifications for each pneumatic pump constructed, modified, or reconstructed.

(ii) Records of deviations in cases where the pneumatic pump was not operated in compliance with the requirements specified in § 60.5393a, including the date and time the deviation began, duration of the deviation, and a description of the deviation.

(iii) Records on the control device used for control of emissions from a pneumatic pump including the installation date, and manufacturer's specifications. If the control device is designed to achieve less than 95-percent emission reduction, maintain records of the design evaluation or manufacturer's specifications which indicate the percentage reduction the control device is designed to achieve.

(iv) Records substantiating a claim according to § 60.5393a(b)(5) that it is technically infeasible to capture and route emissions from a pneumatic pump to a control device or process; including the certification according to § 60.5393a(b)(5)(ii) and the records of the engineering assessment of technical infeasibility performed according to § 60.5393a(b)(5)(iii).

(v) You must retain copies of all certifications, engineering assessments, and related records for a period of five years and make them available if directed by the implementing agency.

(17) For each closed vent system routing to a control device or process, the records of the assessment conducted according to § 60.5411a(d):

(i) A copy of the assessment conducted according to § 60.5411a(d)(1);

(ii) A copy of the certification according to § 60.5411a(d)(1)(i); and

(iii) The owner or operator shall retain copies of all certifications, assessments, and any related records for a period of 5 years, and make them available if directed by the delegated authority.

(18) A copy of each performance test submitted under paragraph (b)(9) of this section.

■ 24. Section 60.5422a is amended by revising paragraphs (a), (b), and (c) introductory text to read as follows:

§ 60.5422a What are my additional reporting requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of § 60.487a(a), (b)(1) through (3) and (5), and (c)(2)(i) through (iv) and (vii) through (viii). You must submit semiannual reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI website (*https://www3.epa.gov/ttn/chief/cedri/*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, submit the report to the Administrator at the appropriate address listed in § 60.4. Once the form has been available in CEDRI for at least 90 days, you must begin submitting all subsequent reports via CEDRI. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(b) An owner or operator must include the following information in the initial semiannual report in addition to the information required in § 60.487a(b)(1) through (3) and (5): Number of pressure relief devices subject to the requirements of § 60.5401a(b) except for those pressure relief devices designated for no detectable emissions under the provisions of § 60.482–4a(a) and those pressure relief devices complying with § 60.482–4a(c).

(c) An owner or operator must include the information specified in paragraphs (c)(1) and (2) of this section in all semiannual reports in addition to the information required in § 60.487a(c)(2)(i) through (iv) and (vii) through (viii):

* * * * *

■ 25. Section 60.5423a is amended by revising the section heading and paragraph (b) introductory text and adding paragraph (b)(3) to read as follows:

§ 60.5423a What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities?

* * * * *

(b) You must submit a report of excess emissions to the Administrator in your annual report if you had excess emissions during the reporting period. The procedures for submitting annual reports are located in § 60.5420a(b). For the purpose of these reports, excess emissions are defined as specified in paragraphs (b)(1) and (2) of this section. The report must contain the information specified in paragraph (b)(3) of this section.

* * * * *

(3) For each period of excess emissions during the reporting period, include the following information in your report:

(i) The date and time of commencement and completion of each period of excess emissions;

(ii) The required minimum efficiency (Z) and the actual average sulfur emissions reduction (R) for periods defined in paragraph (b)(1) of this section; and

(iii) The appropriate operating temperature and the actual average temperature of the gases leaving the combustion zone for periods defined in paragraph (b)(2) of this section.

* * * * *

■ 26. Section 60.5430a is amended by:

■ a. Revising the definitions for ''Capital expenditure'' and ''Certifying official'';

■ b. Adding in alphabetical order the definitions for ''Coil tubing cleanout,'' ''Custody meter,'' ''Custody meter assembly,'' and ''First attempt at repair'';

■ c. Revising the definitions for ''Flowback'' and ''Fugitive emissions component'';

■ d. Removing the definitions for ''Gas processing plant process unit'' and ''Greenfield site'';

■ e. Revising the definition of ''Low pressure well'';

■ f. Adding in alphabetical order the definition for ''Major production and processing equipment'';

■ g. Revising the definition for ''Maximum average daily throughput'';

■ h. Adding in alphabetical order the definitions for ''Plug drill-out,'' ''Repaired,'' and ''Screenout'';

■ i. Revising the definition for ''Startup of production'';

■ j. Adding in alphabetical order the definitions for ''UIC Class I oilfield disposal well'' and ''UIC Class II oilfield disposal well'';

■ k. Revising the definition for ''Well site''; and

■ l. Adding in alphabetical order the definition for ''Wellhead only well site''.

The revisions and additions read as follows:

§ 60.5430a What definitions apply to this subpart?

* * * * *

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(1) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where:

(i) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation: $A = Y \times (B \div 100)$;

(ii) The percent Y is determined from the following equation: Y = (CPI of date of construction/most recently available CPI of date of project), where the ''CPI–U, U.S. city average, all items'' must be used for each CPI value; and

(iii) The applicable basic annual asset guideline repair allowance, B, is 4.5.

* * * * *

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 with an affected facility subject to this subpart 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 CAA or the regulations promulgated thereunder are concerned; or

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

Coil tubing cleanout means the process where an operator runs a string of coil tubing to the packed proppant within a well and jets the well to dislodge the proppant and provide sufficient lift energy to flow it to the surface. Coil tubing cleanout includes mechanical methods to remove solids and/or debris from a wellbore.

* * * * *

Custody meter means the meter where natural gas or hydrocarbon liquids are measured for sales, transfers, and/or royalty determination.

Custody meter assembly means an assembly of fugitive emissions components, including the custody meter, valves, flanges, and connectors necessary for the proper operation of the custody meter.

* * * * *

First attempt at repair means, for the purposes of fugitive emissions components, an action taken for the purpose of stopping or reducing fugitive emissions to the atmosphere. First attempts at repair include, but are not limited to, the following practices where practicable and appropriate: Tightening bonnet bolts; replacing bonnet bolts; tightening packing gland nuts; or injecting lubricant into lubricated packing.

* * * * *

Flowback means the process of allowing fluids and entrained solids to flow from a well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The term flowback also means the fluids and entrained solids that emerge from a well during the flowback process. The flowback period begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage. Screenouts, coil tubing cleanouts, and plug drill-outs are not considered part of the flowback process.

Fugitive emissions component means any component that has the potential to emit fugitive emissions of VOC at a well site or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to § 60.5411 or § 60.5411a, thief hatches or other openings on a controlled storage vessel not subject to § 60.5395 or § 60.5395a, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the device's vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

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Low pressure well means a well that satisfies at least one of the following conditions:

(1) The static pressure at the wellhead following fracturing but prior to the onset of flowback is less than the flow line pressure;

(2) The pressure of flowback fluid immediately before it enters the flow line, as determined under § 60.5432a, is less than the flow line pressure; or

(3) Flowback of the fracture fluids will not occur without the use of artificial lift equipment.

Major production and processing equipment means reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, and storage vessels collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water, for the purpose of determining whether a well site is a wellhead only well site.

Maximum average daily throughput means the following:

(1) For storage vessels that commenced construction, reconstruction, or modification after September 18, 2015, and on and before November 16, 2020, *maximum average daily throughput* means the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods.

(2) For storage vessels that commenced construction, reconstruction, or modification after November 16, 2020, *maximum average daily throughput* means the earliest calculation of daily average throughput, determined as described in paragraph (3) or (4) of this definition, to an individual storage vessel over the days that production is routed to that storage vessel during the 30-day PTE evaluation period employing generally accepted methods specified in § 60.5365a(e)(1).

(3) If throughput to the individual storage vessel is measured on a daily basis (*e.g.,* via level gauge automation or daily manual gauging), the maximum average daily throughput is the average of all daily throughputs for days on which throughput was routed to that storage vessel during the 30-day evaluation period; or

(4) If throughput to the individual storage vessel is not measured on a daily basis (*e.g.,* via manual gauging at the start and end of loadouts), the maximum average daily throughput is the highest, of the average daily throughputs, determined for any production period to that storage vessel during the 30-day evaluation period, as determined by averaging total throughput to that storage vessel over each production period. A production period begins when production begins to be routed to a storage vessel and ends either when throughput is routed away from that storage vessel or when a loadout occurs from that storage vessel, whichever happens first. Regardless of the determination methodology, operators must not include days during which throughput is not routed to an individual storage vessel when calculating maximum average daily throughput for that storage vessel.

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Plug drill-out means the removal of a plug (or plugs) that was used to isolate different sections of the well.

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Repaired means, for the purposes of fugitive emissions components, that fugitive emissions components are adjusted, replaced, or otherwise altered, in order to eliminate fugitive emissions as defined in § 60.5397a and resurveyed as specified in § 60.5397a(h)(4) and it is verified that emissions from the fugitive emissions components are below the applicable fugitive emissions definition.

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Screenout means an attempt to clear proppant from the wellbore to dislodge the proppant out of the well.

* * * * *

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, except as otherwise provided in this definition. For the purposes of the fugitive monitoring requirements of § 60.5397a, *startup of production* means the beginning of the continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate, or produced water.

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UIC Class I oilfield disposal well means a well with a UIC Class I permit that meets the definition in 40 CFR 144.6(a)(2) and receives eligible fluids from oil and natural gas exploration and production operations.

UIC Class II oilfield disposal well means a well with a UIC Class II permit where wastewater resulting from oil and natural gas production operations is injected into underground porous rock formations not productive of oil or gas, and sealed above and below by unbroken, impermeable strata.

* * * * *

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For purposes of the fugitive emissions standards at § 60.5397a, well site also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (*e.g.,* centralized tank batteries). Also, for the purposes of the fugitive emissions standards at § 60.5397a, a well site does not include:

(1) UIC Class II oilfield disposal wells and disposal facilities;

(2) UIC Class I oilfield disposal wells; and

(3) The flange immediately upstream of the custody meter assembly and equipment, including fugitive emissions components, located downstream of this flange.

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Wellhead only well site means, for the purposes of the fugitive emissions standards at § 60.5397a, a well site that contains one or more wellheads and no major production and processing equipment.

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■ 27. Table 3 to subpart OOOOa of part 60 is amended by revising the entries for §§ 60.8 and 60.15 to read as follows:

TABLE 3 TO SUBPART OOOOa OF PART 60—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART OOOOa

General provisions citation	Subject of citation	Applies to subpart?	Explanation
*	*	*	* * * *
§ 60.8	Performance tests	Yes	Except that the format of performance test reports is described in § 60.5420a(b). Performance testing is required for control devices used on storage vessels, centrifugal compressors, and pneumatic pumps, except that performance testing is not required for a control device used solely on pneumatic pump(s).
*	*	*	* * * *
§ 60.15	Reconstruction	Yes	Except that § 60.15(d) does not apply to wells, pneumatic controllers, pneumatic pumps, centrifugal compressors, reciprocating compressors, storage vessels, or the collection of fugitive emissions components at a well site or the collection of fugitive emissions components at a compressor station.
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